April 24, 2007

MEMORANDUM TO: Frank Gillespie, Executive Director
Advisory Committee on Reactor Safeguards

FROM: Pao-Tsin Kuo, Director **/RA by Samson Lee for/**
Division of License Renewal
Office of Nuclear Reactor Regulation

SUBJECT: RESPONSE TO CONCERNS RELATED TO THE STAFF REVIEW OF THE OYSTER CREEK LICENSE RENEWAL APPLICATION

The purpose of this letter is to respond, as requested by the Advisory Committee on Reactor Safeguards (ACRS), to concerns raised by Mr. Richard Webster, Staff Attorney, for the Rutgers Environmental Law Clinic, concerning the Nuclear Regulatory Commission's review of the Oyster Creek License Renewal Application. Mr. Webster made presentations at the ACRS Plant License Renewal Subcommittee meeting on January 18, 2007, and the ACRS meeting on February 1, 2007. In letters to the ACRS dated January 16, 2007, and January 31, 2007, Mr. Webster raised concerns about the proposed license renewal and referenced, among other things, the January 2007, Sandia National Laboratories (SNL) structural analysis of the Oyster Creek shell.

The attached enclosure responds to Mr. Webster's concerns related to:

1. Drywell Corrosion Acceptance Criteria and Margins
2. General Electric (GE) and SNL Analyses
3. Torus Corrosion Inspections
4. Possible Stress Corrosion Cracking in the Drywell Liner
5. Statistical Analysis of Oyster Creek Drywell Thickness Data

Should you have any questions, please contact me at 301- 415-1183, or via e-mail at ptk@nrc.gov.

Docket No. 50-219

Enclosure:
As stated

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NRC Staff Response to Mr. Webster's Concerns

Mr. Richard Webster, Staff Attorney for the Rutgers Environmental Law Clinic, made presentations at the Advisory Committee on Reactor Safeguards (ACRS) License Renewal Subcommittee meeting on January 18, 2007, and the ACRS meeting on February 1, 2007. He represents six groups that are interveners in the proceeding on the Oyster Creek license renewal application. The following are NRC staff responses to Mr. Webster's concerns presented during the January 18, 2007, ACRS Plant License Renewal Subcommittee meeting and in letters to the ACRS dated January 16, 2007, and January 31, 2007.

1. **Drywell Shell Corrosion Acceptance Criteria and Margins**

In his January 16, 2007, letter to the ACRS, Mr. Webster provided a preview of the material he planned to present at the January 18, 2007, ACRS Subcommittee meeting. During the Subcommittee meeting he presented slides and discussed his concerns related to corrosion of the drywell shell. The concerns expressed by Mr. Webster have been grouped in three general categories.

a. Drywell Ultrasonic Test (UT) Measurements

- AmerGen failed to adequately measure the extent of corroded areas. (Ltr 1/16/07)
- AmerGen failed to take into account the October 2006 outage measurement results. (Ltr 1/16/07)
- Contiguous drywell shell areas of 0.536 inches thickness measuring more than one square foot probably existed in 1992 and have probably expanded since then. (Ltr 1/16/07)
- There is uncertainty in measurements and corrosion rates. (Slide 1/18/07)
- The margin in the embedded region is unknown. (Slide 1/18/07)
- No measurements were taken in the embedded region. (Transcript (Tr.) 312)
- It is questionable whether all areas thinner than 0.736" have been identified since UT grid measurements are averaged. (Tr. 321-322)
- The applicant's statistics are questionable. (Tr. 325)
- The 2006 external UT measurement results are difficult to follow. (Tr. 330)
- It is questionable whether the applicant used a measurement technique that had no systematic error. (Tr. 333)
- It is possible that external corrosion is occurring despite preventive measures taken or that there is internal corrosion. (Tr. 335)
- Areas up to four square foot were thinner than 0.736 inches even in 1992, and have since probably expanded either due to systematic measurement error in 1992 or corrosion. (Tr. 336)

b. Margins relating to drywell shell thickness above ASME Code criteria

- Margins for both the sand bed and embedded regions need to be identified and quantified. (Slide 1/18/07)
- Margins in the sand bed region range from 0.040" to zero. (Slide 1/18/07)
- There is a significant probability of no margin in the sand bed region. (Slide 1/18/07) (Tr. 347)

ENCLOSURE

c. The visual assessment of the coating alone is inadequate. Better detection of corrosive conditions and faster response are needed. (Tr. 312)

<u>Staff Response to (a) Drywell Ultrasonic Test (UT) Measurements</u>:

Aging management programs require ultrasonic test (UT) measurements of the drywell shell to monitor corrosion rates and verify compliance with ASME Code criteria. As UT probes and UT measurement techniques changed between 1992 and 2006, inconsistencies in the UT measurements may have been introduced. AmerGen's analysis [AmerGen's letter dated June 20, 2006, ML061740573] determined that UT measurement errors could have been caused by a number of reasons, including that caused by the drywell surface roughness and UT probe location repeatability. However, the applicant stated that the potential variables will be considered in the analysis of data during future UT measurements. In its letter, the applicant asserted that future UT measurements will be compared against the previous measurements, and any anomaly, similar to that in 1996 data, will be identified and corrective actions taken. The staff recognizes that the UT measurements may have included such errors, and therefore indicated that the applicant should identify the sources of these errors and minimize the uncertainties associated with the measured results (Safety Evaluation Report (SER) Section 4.7.2, dated March 30, 2007).

By letter dated April 24, 1992, the NRC accepted the results from the General Electric (GE) analysis model used for Oyster Creek drywell shell which showed that the corroded drywell meets ASME Code Section III requirements. The GE analysis assumed a uniform shell thickness of 0.736 in. over the entire sand bed region. UT measurements in Bays 1, 11, 13, 17, and 19 indicate locations where the shell thicknesses were less than 0.736 in. The applicant reviewed these areas using certain ASME Code provisions and determined that (1) a shell thickness of 0.536 in. would be acceptable, as long as such thin areas are no larger than one square foot, and (2) a shell thickness as low as 0.49 in. would be acceptable at isolated locations as long as such pits are located in areas having a diameter of less than 2.5 in. In the June 20, 2006 letter, the applicant clarified that the mean value of each UT measurement grid was compared to the required minimum thickness criterion of 0.736 in., and the individual readings were compared to the minimum required criterion of 0.49 in. As part of the response to a number of questions from the NRC audit team related to the drywell shell degradation, the applicant stated that there were 20 UT measurements in the entire sand bed region that have thicknesses less than 0.736 in. These thickness measurements conservatively cover an area of 0.68 square feet and have an average thickness of 0.703 in. Thus, there is no evidence that an area of up to 4 sq. ft. thinner than 0.736 in. has existed since 1992.

Shell thickness monitoring, including UT measurements taken during the October 2006 outage, confirm that there has been no significant corrosion (i.e., readings were within measurement uncertainty of last readings) in the sand bed region since the application of epoxy coating in the sand bed region in the early 1990's [NRC Inspection Report 05000219/2006013, dated January 17, 2007, ML070170396]. That is, external and internal readings were within measurement uncertainty of prior readings. The outage results, along with the applicant's commitments in a letter dated February 15, 2007 [ML070520252] to monitor the sand bed region every other outage, provide reasonable assurance that these localized thin areas of the shell will not result in a large contiguous area of uniformly reduced thickness.

Regarding the corrosion in the embedded (concrete) portion of the drywell shell, the staff requested information to support the applicant's statement that the shell below the concrete bed having a design thickness of 1.154 in. will not be reduced below the average thickness of the shell in the sand bed area, and that the area below the drywell shell skirt will not be significantly affected by corrosion. During the October 2006 outage, the applicant took a total of 294 UT measurements from Bay 5 trench and 290 measurements from Bay 17 trench [AmGen Letter dated December 3, 2006, ML063390664]. Some of these measurements were taken in the embedded shell area in Bay 5. These measurements, taken for the first time since the plant was constructed in 1969, indicated an average thickness in the embedded shell to be 1.113 in. versus a nominal plate thickness of 1.154 in. Statements that any corrosion in the embedded region will not result in areas thinner than the sand bed region are also based on the literature search regarding the corrosion of carbon steel in the alkaline concrete environment. For the inside portion of the drywell shell embedded in concrete, it appears that the drywell shell is not subjected to a corrosive environment. The most likely source of water inside the drywell during operation is condensate water, which does not contain corrosive materials [NRC Inspection Report dated January 17, 2007]. The staff agrees with the applicant's statement, as long as the concrete bed region is monitored for water on the bed and corrective action is taken according to the applicant's commitments [SER Appendix A, Commitment 27, Items 3, 20, and 21].

<u>Staff Response to (b) Margins relating to drywell shell thickness above ASME Code criteria:</u>

Mr. Webster refers to the margin between the average thickness of the shell and the thickness acceptance criteria. The applicant considers the existing average thickness in the sand bed region as 0.8 in. and the acceptance criterion of 0.736 in., giving a margin of 0.064 in. Based on the UT measurements taken during the October 2006 outage, Mr. Webster notes [in slides 19 to 25 of his January 2007 slides] that in many instances the margins are very slim. Under the Code, the issue of thickness margin is considered from a stress and stability standpoint. The degradation Mr. Webster refers to is located in less than 5% of the total shell area in the sand bed region. The Sandia National Laboratory (SNL) study of the Oyster Creek drywell shell applied the average thickness of each localized corroded area to the entire area of each bay. The results of Sandia's conservative approach for analyzing the shell indicate that the drywell shell can withstand the postulated loads without exceeding the ASME Section III provisions for stress and stability. In addition, the corroded areas will be monitored in accordance with the applicant's commitments [SER Appendix A, Commitment 27, Items 1 and 21].

The GE drywell structural analysis conducted in the early 1990's examined the structural integrity of the drywell shell in terms of stability using the ASME Code Case N-284, "Metal Containment Shell Buckling Design Methods, Section III, Division 1, Class MC," Section 1700. The ASME Code Case provides stability criteria for determining the structural adequacy against buckling of containment shells of various shell geometries. The analysis determined an effective factor of safety, which is defined as the allowable compressive stress divided by the calculated compressive stress. One of the data inputs into the calculation is the assumed thickness of the drywell shell.

For the load combinations containing operational loads (service level B) in the drywell sand bed region, the ASME Code Case N-284, Section-1400 requires a safety factor of 2. The safety factor is utilized to account for the uncertainties associated with loading, material properties, fabrication, and analysis approximations. The UT measurements taken during the October 2006 refueling outage confirmed that the drywell shell meets the ASME Code criterion, and that the drywell shell thickness was greater than the thickness assumed in the GE analysis. The ASME Code compliance satisfies the NRC guidance for structural integrity of the drywell shell [NRC Standard Review Plan, Section 3.8.2, and Regulatory Guide 1.57].

The applicant has committed [SER Appendix A, Commitment 27] to perform UT inspections of the drywell shell in the sand bed region every other refueling outage. If the UT measurements deviate from previous measurements, the applicant has committed to perform and provide to the NRC an engineering analysis and an operability determination prior to restart from the refueling outage. On the basis of recent UT measurements and the applicant's commitments, the staff concluded that the applicant has demonstrated that for the drywell corrosion concern, the effects of aging on the intended functions will be adequately managed for the period of extended operation.

<u>Staff Response to (c) Visual Assessment of Coatings:</u>

AmerGen's aging management program does not rely on visual inspections of the drywell coatings alone. The applicant committed [SER Appendix A, Commitment 27, Items 4 and 21] to perform both visual and UT inspections of the drywell every other outage.

AmerGen plans to perform the drywell exterior surface coating examinations in accordance with the requirements of Subsection IWE of Section XI of the ASME Code. The Code requires that "[w]hen a containment vessel or liner is painted or coated to protect surfaces from corrosion, preservice and inservice visual examination shall be performed without the removal of the paint or coating." AmerGen has also committed to follow the provisions of Generic Aging Lessons Learned (GALL) Report, AMP (Aging Management Program) XI.S8, "Protective Coating and Maintenance Program," for monitoring the epoxy coating integrity on the exterior of the drywell shell in the sand pocket area, and for the interior surface of the Oyster Creek torus [SER p. 3-163]. The AMP recommends that the coating be monitored in accordance with the provisions of ASTM D 5163-96, "Standard Guide for Establishing Procedure to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant." The implementation of these provisions in examining the coated surfaces ensures that any defects or damage in the coating will be identified and corrective actions taken to establish the integrity of the coating. With the applicant's commitment to perform the examination of these coatings in accordance with these standards, the staff finds the protective coating monitoring and maintenance program acceptable because it ensures that the requirements of ASME Code IWE related to coatings inspection will be implemented during the period of extended operation [SER p.3-166].

2. General Electric (GE) and SNL Analyses

In his January 16 and January 31, 2007, letters to the ACRS, and during his January 18, 2007, presentation to the ACRS Subcommittee, Mr. Webster identified concerns related to the GE structural analyses performed in the early 1990's and the Sandia National Laboratories (SNL) structural analysis issued on January 12, 2007 (ML070120395). Mr. Webster's concerns are summarized in bullets below and the staff response follows.

- It is not clear that the General Electric (GE) structural integrity analysis is reliable. (Tr. 326)

- The GE study used a 36 degree symmetric model, which couldn't predict the lowest mode of buckling. (Tr. 314)
- The GE analysis cannot model the first 9 modes of buckling. (Ltr. 1/31/07)
- The SNL analysis does not predict the current condition of the drywell. (Tr. 316)
- The GE structural integrity analysis used an erroneous capacity reduction factor. (Ltr 1/16/07)
- No justification has been given for use of two thin areas in the SNL model or why the SNL model would be bounding. (Tr. 330)
- The GE predicted stresses at the bottom of the sand bed area under accident conditions are large and exceed the assumed allowable stresses. (Ltr 1/16/07)
- The SNL analysis shows the drywell does not meet the safety factor of 2 requirement because buckling could occur in upper regions of the drywell at stresses corresponding to a safety factor of 1.95. (Ltr 1/16/07)
- The recent modeling by SNL invalidated AmerGen's current approach to aging management of the drywell shell. (Ltr. 1/31/07)
- It is not clear that the GE structural integrity analysis is reliable. (Tr. 326)

Staff Response

Background:

The GE analysis, which the staff reviewed and approved in 1992, is part of the Oyster Creek current licensing basis. In its Statement of Considerations [60 FR 22464, May 8, 1995], the Commission stated that for license renewal, "plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term." Consequently, the NRC staff used the GE analysis modeling, assumptions, and results in its review of the drywell aging management program. The staff's safety evaluation report dated April 24, 1992, forms part of Oyster Creek's current licensing basis.

On the basis of its review of the Oyster Creek license renewal application, the October 2006 results indicating lack of significant corrosion and the applicant's commitments to enhance the aging management programs associated with the drywell shell, the staff determined in the SER, issued in March 2007, that there is reasonable assurance that the drywell would be able to perform its intended functions during the period of extended operation. An analysis was performed by Sandia National Laboratory regarding the drywell shell during the staff review for the SER, and is discussed below.

The SNL analysis does not invalidate the GE analysis, which is part of the current licensing basis for Oyster Creek and continues to form the basis for acceptance in accordance with the ASME Code. The staff reviewed and approved the GE analysis in 1992, with the assistance of Brookhaven National Laboratory (BNL), and found it acceptable provided the licensee performs UT thickness measurements to confirm that the thickness of corroded areas are as projected and that corroded areas are localized. Both the GE and Sandia analyses showed that the drywell meets ASME Code requirements for stress and stability.

Comparison of Sandia Analysis and GE Analysis:

The 3-D SNL analysis incorporates structural parameters and boundary conditions that were approximated in the GE analysis. The GE analysis was performed within the computational capability available at that time. The GE Analysis Report 9-4, "An ASME Section VIII Evaluation of Oyster Creek Drywell, for without sand case, Part 2 Stability Analysis," (November 1990), indicates GE computed four buckling modes in the eigenvalue buckling analysis and found no buckling in areas outside of the sand bed region. The SNL analysis, which included degraded shell conditions, predicted that the middle spherical areas showed certain signs of buckling in the sand bed region. In a complex structure like the Oyster Creek drywell shell, various buckling modes can occur at different locations. However, the first buckling mode was determined by GE to occur within the sand bed near Bays 13 and 15. GE calculated the dominant buckling load for the drywell liner, and found that the first buckling mode was limiting. Both analyses demonstrated that the drywell shell met the minimum ASME Code requirements for buckling.

The SNL analysis was not an attempt to replicate the GE structural analysis. The SNL analysis used information from the GE analysis including load combinations, seismic loading, and other loads, but made assumptions, for example, about modeling vent lines, spacing of beam seats, and the coefficient of thermal expansion, since the GE analysis does not include these details. A list of assumptions is contained in Chapter 6 of the SNL analysis.

The SNL analysis involved, in part:

- Using the conservatively biased average thicknesses in each bay (derived from the GPU's 1992 UT measurements), and assuming the lowest recorded UT measurements in Bays 1 and 13 extended over two total areas of almost 4 sq. ft., to analyze whether the degraded drywell shell can withstand the postulated loadings without exceeding the relevant ASME acceptance criteria. These assumptions bounded corroded areas where UT measurements identified shell thicknesses less than 0.736 in. Since the UT measurements taken during the October 2006 outage did not show significant difference from the 1990s UT measurements, the staff believes that the analysis bounds the current condition of the drywell shell.

- Assessing the average minimum thickness required to meet the ASME criteria. These analyses were performed for one postulated loading combination, i.e. the combination containing the loads imposed during refueling activities combined with hypothetical external pressure of 2 psi, and seismic load.

- Performing an eigenvalue extraction to assess the frequency differences that can occur due to the degraded drywell shell and to assess if the use of the static coefficients for seismic loading was justifiable for degraded shell.

The first part of the analysis indicated that the degraded Oyster Creek drywell shell can withstand the plant specific postulated loadings without exceeding the relevant ASME Code criteria for stresses and stability (i.e., buckling). For the refueling load case, the buckling analysis utilized the basic capacity reduction factor, and arrived at the safety factor of 2.15 (> 2.0). The analysis supported the staff's judgment that the degraded drywell shell can withstand the postulated loadings without exceeding the ASME Code acceptance criteria.

The eigenvalue extraction evaluation indicated that the frequency differences were minimal and therefore the use of the static coefficients for seismic loading was justified for the degraded shell.

The SNL analysis evaluates the minimum thickness that is needed to satisfy the ASME Code required safety factor of 2.0 for the refueling load case. SNL determined that the average shell thickness required would be 0.844 in., which was calculated using a capacity reduction factor of 0.207, which was lower than that used by the GE analysis.
Capacity Reduction Factor:

The GE analysis used a modified capacity reduction factor of 0.326 for the refueling loading case, and determined that the use of the minimum average shell thickness of 0.736 in. is valid. The calculation of the modified capacity reduction factor is based on the provision in Paragraph-1500 of the ASME Code Case N-284 which states in part, “The influence of internal pressure on a shell structure may reduce the initial imperfections and therefore higher values of capacity reduction factor may be acceptable.” Internal pressure induces tensile stresses in a spherical shell. Likewise, the gravity load during a refueling outage also induces a tensile hoop stress in the shell. The effect of internal pressure on buckling of cylindrical shells under axial loads was studied by the author of Code Case N-284, who developed a modified capacity reduction factor that accounted for the effect of the internal pressure. Based on available data, the author also concluded that this capacity reduction factor is also applicable to spherical shells with internal pressure as well as spherical shells where a tensile hoop stress is developed as a result of gravity loading. GE interpreted this to be applicable in accordance with Paragraph-1500 of the Code Case if the capacity reduction factor is determined by using an equivalent pressure, corresponding to the known tensile hoop stress. In addition, inclusion of hoop tension was subsequently included in ASME Code Section VIII Code Case 2286, 1998.

In its 1992 Safety Evaluation, the staff accepted the use of GE’s modified capacity reduction factor as being consistent with ASME Code Case N-284. Based on the review for computing the modified capacity reduction factor in the GE’s 1992 analysis, the staff again concluded in SER section 4.7.2 that the use of the modified capacity reduction factor is acceptable.

Evaluation of UT Measurements and Stresses:

On the basis of individual UT measurements on the outside of the drywell shell in the sand bed region, the SNL analysis utilized an average thickness of the UT results in the most degraded area in each of the 10 bays. The SNL analysis assumed about a 4 sq. ft. (18" x 30") localized area of 0.705 in. thickness in Bay 1 and 0.618 in. thickness in Bay 13, to conservatively bound the thickness measurements in the most corroded bays. Even though the UT measurements taken in the localized areas varied from 0.965 in. to 0.618 in., the SNL analysis, in general, assumed that the thickness of the localized area of each bay was equal to the lowest UT measurements in each bay. These assumptions were not realistic, but conservative and bounding.

Stresses that potentially exceed the allowable stress under accident conditions are for the meridional and circumferential primary plus secondary stresses at the bottom of the lower sphere. These values exceed the assumed allowable even for the case with no degradation. The ASME Code does not require an evaluation for primary plus secondary stresses, such as thermal effects, for Level C loading. This approach is consistent with the Standard Review Plan, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” (SRP) Section 3.8.2 (NUREG-0800) and Regulatory Guide 1.57, “Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components.”

In the SNL structural analysis, the buckling at the upper beam seat for the refueling load case with degradation does not meet the required factor of safety of 2. The potential constraint provided by the attached beam was not included in this analysis. As SNL did not have the beam constraint information, the SNL model distributed the load for the beam seats evenly among the 20 seats for both the upper and lower seats. Since the GE analysis included these beam constraints in its analysis, the analysis showed the first buckling mode in the sand bed area. The staff believes that the consideration of these beam seat constraints in SNL analysis would not have resulted in the earlier buckling mode in this area.

Future Analysis:

During the February 1, 2007, ACRS meeting and in a letter dated February 15, 2007, AmerGen stated that it will perform a 3-D (dimensional) finite element analysis of the Oyster Creek drywell prior to the period of extended operation. Consistent with an ACRS recommendation contained in the ACRS report to the NRC Chairman dated February 8, 2007, if the license is renewed, the NRC staff will require the applicant to submit this new analysis of the drywell shell prior to entering the period of extended operations.

3. Torus Corrosion Inspections

By letter dated January 16, 2007, Mr. Webster states that AmerGen is attempting to age manage a corroding safety-critical component through a combination of visual inspections of a protective coating and occasional UT measurements of identified degraded areas.

In his letter dated January 16, 2007 and at the January 18, 2007, ACRS Subcommittee meeting, Mr. Webster expressed concern about the May 1, 2006 torus commitments and the applicant’s failure to implement commitments associated with inspections for water. (Tr. 341)

Staff Response

Staff evaluation of aging management of the torus is discussed in detail in the staff's Audit Report dated August 18, 2006, and in the March 30, 2007 SER, Sections 3.0.3.1.8, 3.0.3.2.22, and 3.5. The staff found the applicant’s aging management program consistent with GALL AMP XI. S8, “Protective Coating Monitoring and Maintenance Program,” with enhancements. The staff determined that the applicant’s program would ensure that the requirements of ASME Code IWE related to coatings inspection will be implemented during the period of extended operation.

The applicant committed in a letter dated May 1, 2006 to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the corrective action process for further evaluation. This commitment was eliminated in a letter from AmerGen dated June 23, 2006 (ML061800302) and was replaced by another commitment in a letter dated July 7, 2006 (ML061940020) [SER Appendix A, Commitment 27, Item 6]. The applicant committed to visually inspect the coating in all 20 bays of the suppression chamber (torus) every other refueling outage during the period of extended operation in accordance with ASME Section XI, Subsection IWE, per the applicant’s Protective Coatings Program.

These improvements were incorporated into the inspection implementing documents prior to the October 2006 inspections, as noted in the staff's inspection report. NRC inspectors conducted an inspection of the Oyster Creek October 2006 refueling outage. The team documented its findings in Inspection Report 05000219/20006013, dated January 17, 2007 [ML070170396]. The inspection team reviewed supporting documentation (AmerGen Specification SP-1302-52-120 Revision 3, August 9, 2006) and interviewed applicant personnel to confirm the adequacy of the license renewal conclusions from the visual inspections conducted of the torus. The inspection team noted that commitments for the torus were met. The visual test inspection procedures contained appropriate criteria for reporting non-conforming conditions and for dispositioning non-conforming conditions. On the basis of the inspection findings (IR 05000219/20006013 p.5), the staff determined that commitment 2 for the torus identified in the applicant's letter dated July 7, 2006, had been completed.

Based on the staff's understanding of (1) the current condition of the torus, (2) the applicant's plan to refine the pit depth acceptance criteria, and (3) the scope of the coating inspection conducted every 4 years, the staff concluded that the applicant's AMP for the suppression chamber (torus) provides reasonable assurance that the effects of aging will be adequately managed during the period of extended operation [SER p. 3-130].

The applicant committed [SER Appendix A, Commitment 27 and 33] to perform UT and visual inspections of interior surfaces of the torus shell and vent system every other refueling outage. Based on the results of the inspections performed from 1993 to 2006, the applicant concluded that the torus shell thickness has remained virtually unchanged from its as-built wall thickness of 0.385 inches following the repair and recoating efforts performed in 1984. Five isolated pits, ranging from 0.042 to 0.068 inches in depth, are monitored and trended during each inspection. The applicant also credits the water chemistry program to manage aging of the torus. On the basis of the commitments, the staff determined in the safety evaluation report that these programs provide reasonable assurance that the torus corrosion is adequately managed during the period of extended operations.

As noted in SER Page 4-44, during a March 2006 inspection walkdown of the torus, the applicant found water in three 5-gallon containers that were used to collect water leakage from the sand bed drains. Two of the 3 containers were found nearly full. The third container was approximately half full. Inspection of the drain lines showed that the lines were dry and that water in the containers was not due to a water leakage. The containers were closed to prevent an overflow and there was no water ponding found on the floor. As documented in the staff's Inspection Report 05000219/2006007 dated, September 21, 2006 [ML062650059], as long as the coating of the exterior surface of the former sand bed area is maintained, any amount of water can be present and have no effect on the corrosion rate. The thickness of the cylindrical portion of the liner is managed using ultrasonic testing and this program will capture any changes in corrosion rate due to water in the liner gap. The staff also noted that AmerGen has taken corrective actions to ensure, in the future, the drains are monitored, and that strippable coating is applied.

Following the ACRS meeting on February 1, 2007, Mr. Webster wrote letters dated March 2, 2007 and March 20, 2007, to NRC concerning water found in drywell sand bed area drain bottles. During the aging management program audit from January 23-27, 2006, the applicant provided the staff information concerning the collected water. The applicant issued a report, in accordance with its corrective action process, to investigate the source of water and evaluate its impact on the drywell shell. The staff considered this operating experience during its review of the license renewal application [SER Section 4.7.2.2]. The NRC is preparing a separate response to Mr. Webster's March 2 and March 20, 2007, letters.

4. Possible Stress Corrosion Cracking in the Oyster Creek Drywell Shell

Dr. Rudolf H. Hausler states in an attachment to Mr. Webster's letter of January 16, 2007, that a case can be made that all the conditions for stress corrosion cracking (SCC) are present or potentially present in the drywell liner.

<u>Staff Response</u>

Staff guidance is provided in NUREG-1800, Rev. 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," and NUREG-1801, Rev. 1, "Generic Aging Lessons Learned (GALL) Report." The staff guidance does not identify an aging effect/aging mechanism for cracking due to SCC for carbon steel.

However, the staff guidance identifies SCC as an aging mechanism for stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds, and recommends further evaluation by the applicant for additional examinations/evaluations. The staff reviewed the applicant's evaluations in Section 3.5.2.2, Subsection "Cracking Due to Stress Corrosion Cracking (SCC)," of the SER, dated March 30, 2007

> SCC is an aging mechanism that requires the simultaneous action of a corrosive environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements eliminates susceptibility to SCC. Stainless steel elements of primary containment and the containment vacuum breakers system, including dissimilar welds, are susceptible to SCC. However these elements are located inside the containment drywell or outside the drywell in the reactor building and are not subject to a corrosive environment as discussed below. The drywell is made inert with nitrogen to render the primary containment atmosphere non-flammable by maintaining the oxygen content below 4 percent by volume during normal operation. The normal operating average temperature inside the drywell is less than 139°F and the relative humidity range is 20 to 40 percent. The reactor building normal operating temperature range is 65°F to 92°F except in the trunnion room where the temperature can reach 140°F. The relative humidity is 100 percent maximum. Both the containment atmosphere and indoor air environments are non-corrosive (chlorides <150 ppb, sulfates <100 ppb, and fluorides <150 ppb). Thus, SCC is not expected to occur in the containment penetration bellows, penetration sleeves, and containment vacuum breakers expansion joints, piping and piping components, and dissimilar metal welds. A review of plant operating experience identified no cracking of the components and primary containment leakage has not been identified as a concern. Therefore, the existing 10 CFR Part 50, Appendix J Program leak tests and the ASME Section XI, Subsection IWE Program are adequate to detect cracking. Observed conditions with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs are described in SER Section 3.0.

On the basis of its review, the staff determined that the license renewal application is consistent with the GALL Report and that the applicant has demonstrated that SCC will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

5. Statistical Analysis of Oyster Creek Drywell Thickness Data

In his January 31, 2007 letter, Mr. Webster stated that a November 9, 2006, AmerGen's analysis, which was attached to his letter, confirmed that the shell in the sand bed region is now thinner than was measured in 1992.

Staff Response:

During the February 1, 2007, ACRS meeting, the applicant explained that the analysis that Mr. Webster attached to his letter was an internal draft study intended to identify areas of increased corrosion in the sand bed area. The draft study used statistical analysis to compare UT measurements taken in 1992 and 2006. The applicant stated that subsequent analysis, completed in January 2007, concluded that there was no increase in corrosion, and determined that the thinner UT measurements resulted from different techniques used to obtain UT measurements between 1992 and 2006 (Tr. 261). This analysis was Exhibit 4 to a March 5, 2007 pleading filed by AmerGen in the license renewal proceeding.

Letter to F. Gillespie, from P.T. Kuo, dated April 24, 2007

SUBJECT: RESPONSE TO CONCERNS RELATED TO THE STAFF REVIEW OF THE OYSTER CREEK LICENSE RENEWAL APPLICATION

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