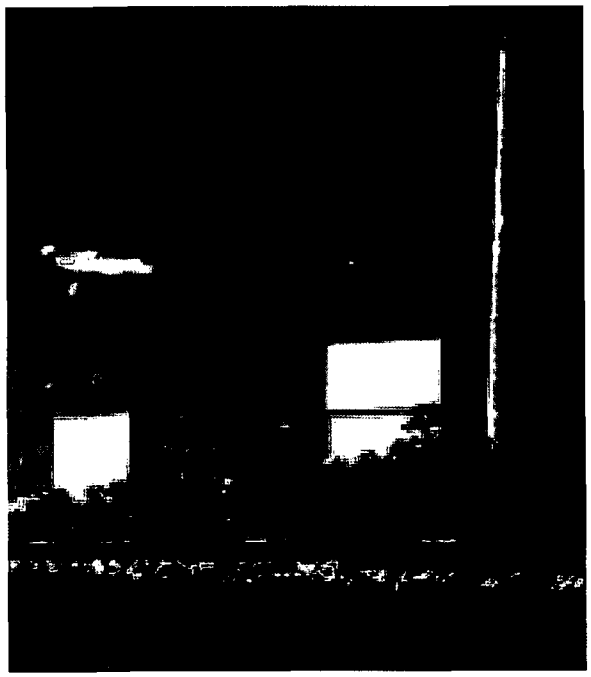
Oyster Creek License Renewal Project

Drywell Monitoring Program



Information for ACRS Subcommittee

Reference Material

Volume 4

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10 CFR 50
10 CFR 51
10 CFR 54

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April 7, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Response to NRC Request for Additional Information, dated March 10, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)

Reference: "Request for Additional Information for the Review of the Oyster Creek Nuclear Generating Station, License Renewal Application (TAC No. MC7624)," dated March 10, 2006

In the referenced letter, the NRC requested additional information related to Section 4.7 of the Oyster Creek Generating Station License Renewal Application (LRA). Enclosed are the responses to this request for additional information.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 04-07-2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosure: Response to 03/xx/06 Request for Additional Information

cc: Regional Administrator, USNRC Region I, w/o Enclosure
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosure
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosure
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosure
USNRC Senior Resident Inspector, OCGS, w/o Enclosure
Bureau of Nuclear Engineering, NJDEP, w/Enclosure
File No. 05040

Enclosure

Response to 3/10/06 Request for Additional Information
Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

RAI 4.7.2-1
RAI 4.7.2-2
RAI 4.7.2-3
RAI 4.7.2-4
RAI 4.7.2-5

RAI 4.7.2-1

Based on the monitoring of the drywell thickness to date, the applicant is requested to provide the following information:

(a) For the drywell corrosion existing during the late 1980s, and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done and the areas considered for identifying the areas of corrosion have been adequate.

(b) Provide a summary of the factors considered in establishing the minimum required drywell thicknesses at various elevations of the drywell.

(c) LRA Reference 4.8-21 discusses pros and cons of various methods of mitigating the drywell shell corrosion. Provide a summary of the actual mitigating actions taken and their effectiveness.

(d) Provide a comparative graph (or chart) showing the drywell thickness based on the assumed corrosion rate and that actually found after the mitigating actions were implemented.

Response:

(a) Oyster creek employed a robust process that establishes confidence in the adequacy of the nature and location of sampling done and the areas considered for identifying the areas of corrosion have been adequate. Elements of the process evolved over several years and were defined in several technical documents submitted to the NRC in 1990 (see attachment 1). A summary of this process is provided below.

Inspections using UT thickness measurements were conducted during refueling outages and outages of opportunity between 1986 and 1989 to establish and characterize the extent of corrosion of the drywell shell. The initial UT measurements were not based on a sampling process. Instead the measurements were taken in areas that correspond to locations where water leakage was observed from the sand bed region drains. The UT measurements were then expanded around the drywell perimeter and vertically to establish locations affected by corrosion. Approximately 1000 ultrasonic (UT) thickness measurements were taken to identify thinnest areas. In addition, core samples of the drywell shell were taken at seven locations, believed to be representative of general wastage, to confirm UT results (Ref. 1). Based on the results of these inspections, elevations 11'-3", 50'-2", and 87'-5" were identified for monitoring. Elevation 11'-3", which corresponds to the sand bed region, showed the highest corrosion rate in 1987 (up to 39.1 +/-3.4 mils per year) based on 1986, and 1987 UT measurements. The high rate of corrosion in the sand bed region prompted corrective action of a physical nature that involved removal of the sand. As a result, corrosion of the drywell shell in the sand bed region was addressed differently than the upper region of the drywell.

Corrosion in the sand bed region

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

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

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

Corrosion of the upper region, above the sand bed region

Based on the results of approximately 1000 UT measurements, Oyster Creek continued to monitor elevations 50'-2", and 87'-5" in the regions above the sand bed region. A third elevation, 51'-10", was added to the scope of inspection after it was determined that the supplied plate thickness is slightly less than the adjacent 50'-2". For each elevation, UT measurements spaced approximately 1" within a 6"x6" array were taken from inside the drywell around the entire perimeter of each elevation. Engineering evaluation of the UT results concluded that monitoring of 12 locations would represent the drywell shell condition and provide reasonable assurance that significant corrosion would be detected prior to a loss of an intended function. This is because the 12 locations were selected considering the degree of drywell shell thinning and the minimum required thickness to

satisfy ASME stress requirements. The locations are, 7 locations 50'-2", 3 locations at elevation 87'-5", and 2 locations at elevation 51'-10". These locations are inspected from the inside of the drywell shell on a frequency of every other refueling outage.

In response to NRC Staff concern regarding whether the inspected locations represent the condition of the entire drywell, in 1990 GPU prepared a new random UT inspection plan (also known as augmented inspection) designed to address the concern. The plan was based on a non-parametric statistical approach using attribute sampling that assumes no prior knowledge of the distribution of corrosion above the sand bed region. It consisted of random UT testing of 57 plates using the 6"x6" grid. Acceptance criteria are that the mean and local thickness of the shell equals or exceeds the required minimum thickness plus a corrosion allowance necessary in order to reach the next inspection.

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

The augmented inspection plan, the original inspection plan, and justification for sampling techniques and statistical methodology were submitted to the NRC on November 26, 1990. In its Safety Evaluation dated November 1, 1995, the Staff noted that the licensee provided a table of UT measurement results from the 15th refueling outage inspection. This table shows the locations of the measurements, the nominal as-constructed thickness, the minimum as-measured thickness, the ASME Code required thickness and the corrosion margin available at the time. The Staff found the current program, based on the submitted information acceptable. The Staff also noted in the Safety Evaluation that since water leaking from the pools above the reactor cavity has been the cause of corrosion, the licensee should make a commitment to the effect that an additional inspection of the drywell will be performed about 3 months after discovery of significant water leakage onto the outside of the drywell shell. Oyster Creek is committed to inspect the drains for leakage during refueling outages and during plant operation. The source of water leakage will be investigated and appropriate corrective actions taken, including an evaluation of the drywell shell to ensure drywell integrity. A review of plant documentation did not provide objective evidence that the commitment has been implemented since 1998. Issue Report #348545 was issued in accordance with Oyster Creek corrective action process to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future.

During a recent walkdown of the torus by the system engineer, water was found in three 5-gallon containers that are installed to collect water leakage from the sand bed drains. Two of the 3 containers were found nearly full. The third container was approximately half full. Inspection of the drain lines shows that the lines are currently dry and that water in the containers is not due to a current water leakage.

The containers are closed such that their overflow is unlikely as confirmed by no water

ponding on the floor. Thus it is concluded with reasonable assurance that the volume of water is limited to what is contained in the containers. This small amount of water is not expected to have significant impact on the drywell shell and on the coating of the shell since the coating is designed for submerged environment. Furthermore, inspection of sand bed region coating conducted in 2004 did not indicate coating degradation or indications of drywell shell corrosion. Similarly, UT examinations on the upper region of the drywell showed a decrease in the corrosion rate since the previous inspection in 2000. Thus, the small volume of water found in the bottles should not have created an environment that would result in significant corrosion to the drywell shell. Issue Report #00470325 was issued, in accordance with Oyster Creek corrective action process, to investigate the source of water and evaluate its impact on the drywell shell.

Based on the discussion above and as indicated in the tables supplied in response to item d) below, Oyster Creek concluded that drywell corrosion is effectively managed both during the current and proposed renewed terms of plant operation. The monitored locations under the current term were subject to extensive UT measurements conducted over several years. NRC Staff found the sampling methodology to identify these locations, and the results of inspections, acceptable for the current term. The same locations will be inspected during the extended period of operation.

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

Water intrusion into the gap between the drywell shell and the drywell shield wall was identified as the cause for corrosion. Corrective actions have been taken to mitigate corrosion in the sand bed region and in the upper region of the drywell. Corrosion of the drywell shell in the sand bed region has been arrested. These actions also have effectively reduced the rate of corrosion to a negligible amount in the upper region as demonstrated by UT thickness measurements (see Table-1, and Table-2). Oyster Creek and its consultants performed stress and buckling analyses considering all design basis loads and load combinations. The results of these analyses indicate that buckling controls the minimum drywell shell thicknesses in the sand bed region while areas above the sand bed region are controlled by accident pressure membrane stresses. In both cases, the minimum measured drywell shell thickness satisfies ASME Section III requirements.

(b) The factors considered in establishing the minimum required drywell thickness at various elevations of the drywell are described in detail in engineering analyses documented in two GE Reports, Index No. 9-1, 9-2, and 9-3, 9-4. Report Index No. 9-1, 9-2 was generated for the drywell condition with sand in the sand bed region and Report Index No. 9-3, 9-4 is for the drywell condition without sand in the sand bed region (see Attachment 2 &3) The two reports were transmitted to the NRC Staff in December 1990 and in 1991 respectively. Report Index No. 9-3, 9-4 was revised later to correct errors identified during an internal audit and was resubmitted to the Staff in January 1992. Analysis described in Report Index No. 9-3, 9-4 (i.e., without sand) is the current

applicable analysis to the drywell.

The analysis is based on the original Code of record, ASME Code, Section VIII, and Code Cases 1270N-5, 1271, and 1272N-5. The Code and the Code Cases do not provide specific guidance in two areas. The first relates to the size of a region of increased membrane stress due to thickness reductions from local or general corrosion effects, and the second pertains to the allowable stresses for Service Level C or post-accident conditions. In the first case, guidance was sought from ASME Section III, NE-3213.10. For Service Level C or post-accident conditions, the Standard Review Plan was used as guidance to develop the allowable stresses.

The analysis is based on a 36-degrees section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the vent bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis considered drywell geometry and materials, thickness reduction from corrosion, test loads, normal operating loads, design basis accident loads, seismic loads, refueling loads, and design basis load combinations. Pressure and temperature were in accordance with approved Technical Specification Amendment No. 165, which established a revised design bases accident pressure of 44 psig and accident temperature of 292°F. The results of the analysis show that the minimum required ASME Code thickness of the drywell shell above the sand bed region is controlled by membrane stresses and the minimum drywell shell thickness in the sand bed region is controlled by buckling. The minimum required ASME Code thicknesses above the sand bed region are shown in Table-1.

For the sand bed region, the analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches. This thickness satisfies ASME Code requirements and considered the minimum required thickness.

As described above, the buckling analysis was performed assuming a uniform general thickness of the sand bed region of 0.736 inches. However the UT measurements identified isolated, localized areas where the drywell shell thickness is less than 0.736 inches. Acceptance for these areas was based on engineering calculation C-1302-187-5320-024.

The calculation uses a Local Wall Acceptance Criteria". This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick so long as the small 12" by 12" area is at least 0.536" thick. However the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, the minimum required linear distances between a 12" by 12" area thinner than 0.736" but thicker than 0.536" and another 12" by 12" area thinner than 0.736" but thicker than 0.536" were not provided.

The actual data for two bays (13 and 1) shows that there are more than one 12" by 12" areas thinner than 0.736" but thicker than 0.536". Also the actual data for two bays

shows that there are more than one 2 ½'" diameter areas thinner than 0.736" but thicker than 0.490". Acceptance is based on the following evaluation.

The effect of these very local wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load.

To begin the discussion we will describe the buckling of a simply supported cylindrical shell under the influence of lateral pressure and axial load. As described in chapter 11 of the Theory of Elastic Stability, Second Edition, by Timoshenko and Gere, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin walled cylindrical shell both the length and radius would be essentially constants and if the thickness was changed locally the change would have to be significant and continuous over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This approach can be easily extrapolated to any shell of revolution that would experience both an axial load and lateral pressure as in the case of the drywell. This local lobe buckling is demonstrated in The GE Letter Report "Sandbed Local Thinning and Raising the Fixity Height Analysis" where a 12 x 12 square inch section of the drywell sand bed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell. Therefore, to influence the buckling of a shell the very local areas of reduced thickness would have to be contiguous and of the same thickness. This is also consistent with Code Case 284 in Section –1700 which indicates that the average stress values in the shell should be used for calculating the buckling stress. Therefore, an acceptable distance between areas of reduced thickness is not required for an acceptable buckling analysis except that the area of reduced thickness is small enough not to influence a buckling lobe of the shell. The very local areas of thickness are dispersed over a wide area with varying thickness and as such will have a negligible effect on the buckling response of the drywell. In addition, these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region which is located at the midpoint between two vents.

The acceptance criteria for the thickness of 0.49 inches confined to an area less than 2½ inches in diameter experiencing primary membrane + bending stresses is based on ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE-3213.2 and NE-3213.10. In particular NE-3213.10 limits the meridional distance between openings without reinforcement to 2.5 x (square root of Rt) . Also Paragraph NE-3335.1 only applies to openings in shells that are closer than two times their average diameter.

The implications of these paragraphs are that shell failures at these locations from primary stresses produced by pressure cannot occur provided openings in shells have

sufficient reinforcement. The current design pressure of 44 psig for drywell requires a thickness of 0.479 inches in the sand bed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sand bed region exceed the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph are not required for the very local wall thickness evaluation presented in Revision 0 of Calculation C-1302-187-5320-024.

Reviewing the stability analyses provided in both the GE Report 9-4 and the GE Letter Report Sand bed Local Thinning and Raising the Fixity Height Analysis and recognizing that the plate elements in the sand bed region of the model are 3" x 3" it is clear that the circumferential buckling lobes for the drywell are substantially larger than the 2 ½ inch diameter very local wall areas. This combined with the local reinforcement surrounding these local areas indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from the GE Letter Report that a uniform reduction in thickness of 27% to 0.536" over a one square foot area would only create a 9.5% reduction in the load factor and theoretical buckling stress for the whole drywell resulting in the largest reduction possible. In addition, to the reported result for the 27% reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5% over a one square foot area which only reduced the load factor and theoretical buckling stress by 3.5% for the whole drywell resulting in the largest reduction possible. To bring these results into perspective a review of the NDE reports indicate there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch thickness used in GE Report 9-4 which cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Therefore, to effectively change the buckling margins on the drywell shell in the sand bed region a reduced thickness would have to cover approximately one square foot of shell area at a location in the shell that is most susceptible to buckling with a reduction in thickness greater than 25%. This leads to the conclusion that the buckling of the shell is unaffected by the distance between the very local wall thicknesses, in fact these local areas could be contiguous provided their total area did not exceed one square foot and their average thickness was greater than the thickness analyzed in the GE Letter Report and provided the methodology of Code Case N284 was employed to determine the allowable buckling load for the drywell. Furthermore, all of these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffing effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

In summary the minimum required drywell shell thickness is based on analysis conducted in accordance with ASME Code. Factors considered include drywell geometry, material of construction, reduced wall thickness due to corrosion, and applicable design basis loads and load combinations. Accident pressure and temperature are 44 psig and 292°F respectively in accordance with approved Technical Specification Amendment No. 165.

The minimum required thicknesses of the drywell shell above the sand bed region, shown in Table-1, are controlled by membrane stresses. The minimum required general

drywell shell thickness in the sand bed region of 0.736" is controlled by buckling. Localized areas in the sand bed region where the thickness is less than 0.736" are evaluated against a local thickness acceptance criteria (0.49") developed based on ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. Application of these Code Sections is justified as discussed above and specific buckling sensitivity analysis results support the conclusion that, on an average wall thickness basis, buckling of the shell is unaffected by local wall thickness areas as these are distributed over the sand bed region.

(c) The mitigating actions taken to address drywell corrosion include,

- Cleared the former sand bed region drains to improve drainage
- Replaced reactor cavity steel trough drain gasket, which was found to be leaking (see Fig. 1 & Fig.-2).
- Removed water from the sand bed region
- Installed a cathodic protection system in bays with greatest wall thinning in early 1989. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and was removed from service in 1992
- Removed sand in the sand bed region to break up the galvanic cell
- Removed corrosion products from the external side of the shell in the sand bed region
- Upon sand removal, the sand bed concrete floor was found cratered and unfinished. The concrete floor was repaired, finished and coated to permit proper drainage of the sand bed region.
- Applied a silicone seal at the juncture of the drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the embedded drywell shell in concrete.
- Applied a multi-layered epoxy protective coating to the exterior surfaces of the drywell shell in the sand bed region (*i.e.*, one pre-primer coat, and two top coats).
- Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner. This I limits water intrusion into the gap between the drywell shell and the drywell shield wall.
- Confirmed that the reactor cavity concrete trough drains are not clogged (see fig – 2

These mitigating features have been in place since 1992[1]. The most effective feature is the removal of sand in the sand bed region to break up the galvanic cell, which significantly reduced the rate of corrosion in that region. The sand bed region coating is

1 Note: The strippable coating of the reactor cavity wall was not applied during 1994 and 1996 refueling outages.

effective because it is protecting the underlying drywell shell from ongoing corrosion as confirmed by comparison of UT measurements taken in 1992, 1994, and 1996 (see Table-2 below). The other features, except for cathodic protection, are also effective because their implementation limited water intrusion into the gap between the drywell shell and the drywell shield wall thus reducing the rate of corrosion in the upper region of the drywell. A comparison of UT measurements taken in 1992, 1994, 1996, 2000, and 2004 on the upper region of the drywell shell shows that either the corrosion is no longer occurring, or negligible considering UT instruments accuracy (see Table-1 below).

As stated previously the cathodic protection system was installed in bays with greatest wall thinning in early 1989. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and removed from service in 1992.

(d) The following tables provide historical UT thickness measurements, the minimum required thickness, and the nominal thickness of the drywell shell.

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Monitored Elevation	Location	Minimum Required Thickness, inches [5]	Average Measured Thickness [1,2,4], inches											Projected Lower 95% Confidence Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	
Elevation 50' 2"		0.541"												
	Bay 5–D12					0.743 0.745 0.746	0.742 0.745 0.748	0.747 0.747		0.741	0.748	0.741	0.743	No Ongoing Corrosion
	Bay 5– 5H					0.761 0.761	0.755 0.758 0.760	0.759 0.759		0.754	0.757	0.754	0.756	0.738
	Bay 5– 5L					0.706 0.703	0.703 0.705 0.706	0.703 0.707		0.702	0.705	0.706	0.701	No Ongoing Corrosion
	Bay 13–31H					0.762 0.779	0.760 0.758 0.765	0.765 0.763		0.759	0.766	0.762	0.758	No Ongoing Corrosion
	Bay 13–31L					0.687 0.684	0.689 0.678 0.688	0.685 0.688		0.683	0.690	0.682	0.693	No Ongoing Corrosion
	Bay 15–23H					0.758 0.764	0.762 0.762 0.765	0.767 0.763		0.758	0.760	0.758	0.757	0.738
	Bay 15–23L					0.726 0.728	0.726 0.729 0.725	0.726 0.724		0.728	0.724	0.729	0.727	No Ongoing Corrosion

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Monitored Elevation	Location	Minimum Required Thickness, inches [5]	Average Measured Thickness [1,2,4], inches											Projected Lower 95% Confidence Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	
Elevation 51' 10"		0.541"												
	Bay 13–32H					0.716	0.715 0.715 0.720	0.717 0.717		0.714	0.715	0.715	0.713	No Ongoing Corrosion
	Bay 13–32L					0.686	0.683 0.683 0.682	0.683 0.676		0.680	0.684	0.679	0.687	No Ongoing Corrosion
Elevation 60' 10"		0.518"												
	Bay 1–50-22								0.693	0.711	0.693	0.689	0.689	No Ongoing Corrosion
Elevation 87' 5"		0.452"												
	Bay 9–20		0.619	0.622 0.620	0.619	0.620	0.614 0.612	0.629 0.614		0.613	0.613	0.604	0.612	0.604.
	Bay 13–28		0.643	0.641 0.642	0.645	0.643	0.635 0.629	0.641 0.637		0.640	0.636	0.635	0.640	No Ongoing Corrosion
	Bay 15–31		0.638	0.636 0.636	0.638	0.642	0.628 0.627	0.631 0.630		0.633	0.632	0.628	0.630	0.615

Notes:

1. The average thickness is based on 49 Ultrasonic Testing (UT) measurements performed at each location

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

2. Multiple inspections were performed in the years 1988, 1990, 1991, and 1992.
3. The 1993 elevation 60' 10" Bay 5-22 inspection was performed on January 6, 1993. All other locations were inspected in December 1992.
4. Accuracy of Ultrasonic Testing Equipment is plus or minus 0.010 inches.
5. Reference SE-000243-002.

Conclusion:

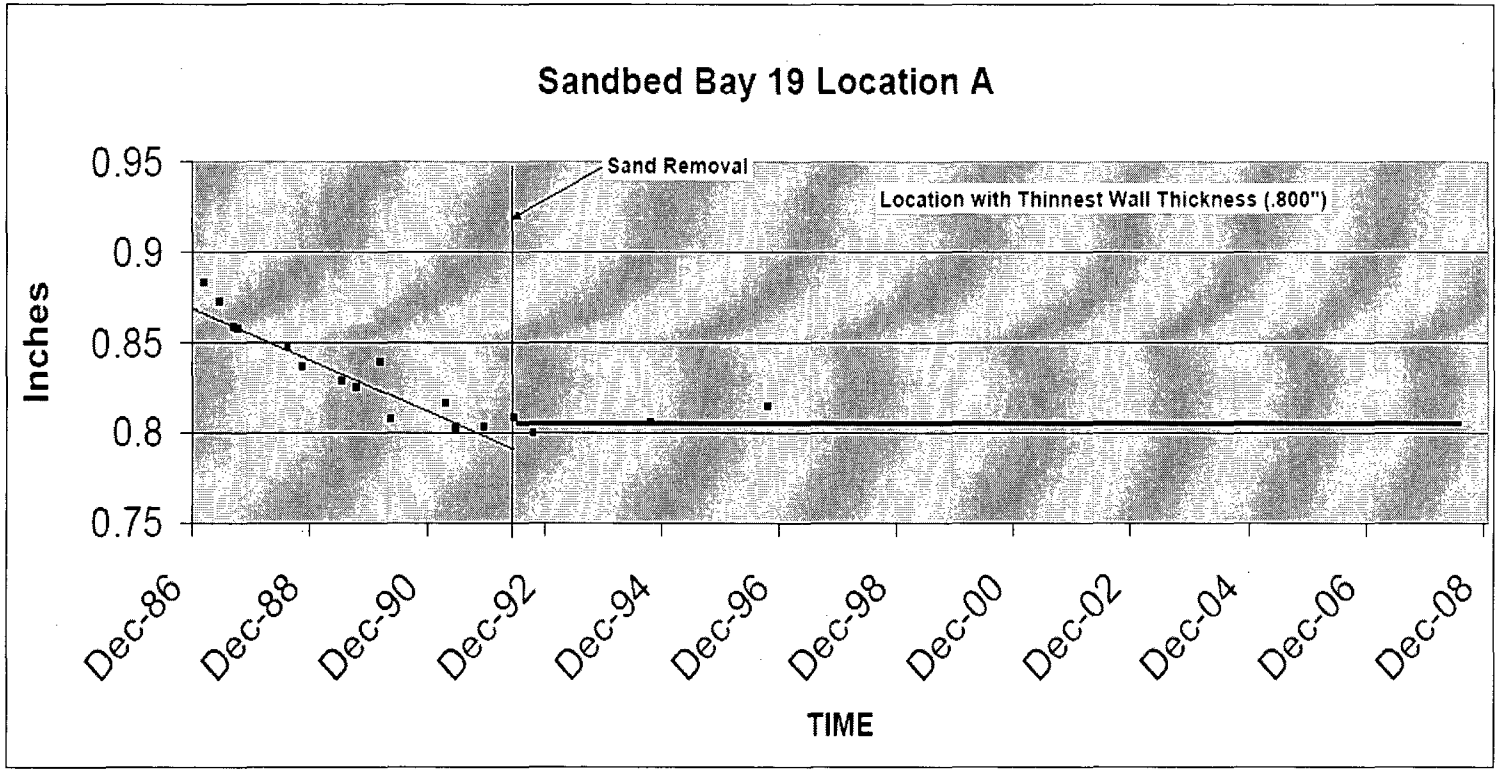
Summary of Corrosion Rates of UT measurements taken through year 2004

- There is no ongoing corrosion at two elevations (51' 10" and 60' 10")
- Based on statistical analysis, one location at elevation 50' 2" is undergoing a minor corrosion rate of 0.0003 inches per year,
- Based on statistical analysis, two locations at elevation 87' 5" are undergoing minor corrosion rates of 0.0005 and 0.00075 inches per year

Table –2 UT Thickness measurements for the Sand Bed Region of the Drywell Shell

Location Bay	Sub Location	Dec 1986	Feb 1987	Apr 1987	May 1987	Aug 1987	Sep 1987	Jul 1988	Oct 1988	Jun 1989	Sep 1989	Feb 1990	Apr 1990	Mar 1991	May 1991	Nov 1991	May 1992	Sep 1992	Sep 1994	Sep 1996
1D									1.115										1.101	1.1514
3D									1.178										1.184	1.181
5D									1.174										1.168	1.173
7D									1.135										1.136	1.138
9A									1.155										1.157	1.155
9D		1.072							1.021	1.054	1.020	1.026	1.022	0.993	1.008	0.992	1.000	1.004	0.992	1.008
11A				0.919	0.905	0.922	0.905	0.913	0.888	0.881	0.892	0.881	0.870	0.845	0.844	0.833	0.842	0.825	0.820	0.830
11C	Bottom				0.917	0.954	0.916	0.906	0.891	0.877	0.891	0.870	0.865	0.858	0.863	0.856	0.882	0.859	0.850	0.883
	Top				1.046	1.109	1.079	1.045	1.009	1.016	1.005	0.952	0.977	0.982	1.018	0.964	1.010	0.970	0.984	1.042
13A		0.919							0.905	0.883	0.883	0.862	0.853	0.855	0.853	0.849	0.865	0.858	0.828	0.843
13C	Bottom													0.909	0.901	0.900	0.931	0.906	0.895	0.933
	Top													1.072	1.049	1.048	1.088	1.055	1.037	1.059
13D									0.962				0.932					1.001	0.959	0.990
15A									1.120										1.114	1.127
15D		1.089							1.056	1.060	1.061	1.059	1.057	1.060	1.050	1.042	1.065	1.058	1.053	1.066
17A	Bottom	0.999							0.957	0.965	0.955	0.954	0.951	0.935	0.942	0.933	0.948	0.941	0.934	0.997
	Top	0.999							1.133	1.130	1.131	1.128	1.128	1.131	1.129	1.123	1.125	1.125	1.129	1.144
17D			0.922		0.895	0.891	0.895	0.878	0.862	0.857	0.847	0.836	0.829	0.825	0.829	0.822	0.823	0.817	0.810	0.845
17/19	Top								0.982	1.019	1.131	0.990	0.986	0.975	0.969	0.954	0.972	0.976	0.963	0.967
	Bottom								1.004	0.999	0.955	1.010	1.006	0.987	0.982	0.971	0.990	0.989	0.975	0.991
19A			0.884		0.873	0.859	0.858	0.849	0.837	0.829	0.825	0.840	0.808	0.817	0.803	0.803	0.809	0.800	0.806	0.815
19B					0.898	0.892	0.888	0.864	0.857	0.826	0.845	0.812	0.837	0.853	0.844	0.846	0.847	0.840	0.824	0.837
19C					0.901	0.888	0.888	0.873	0.856	0.845	0.845	0.831	0.825	0.843	0.823	0.822	0.832	0.819	0.820	0.848

Fig. – 3 Corrosion Trend in Sand Bed Region Bay with highest Drywell Shell Wall Thinning



Based on Calculation C-1302-187-5300-021

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.015	0.7911	05/01/92	0.8071	1.154"	0.736"

Dates	Dec-86	Feb-87	Apr-87	May-87	Aug-87	Sep-87	Jul-88	Oct-88	Jun-89	Sep-89	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
19A		0.88364		0.87293	0.8586	0.85829	0.8486	0.8369	0.8288	0.8254	0.8399	0.8076	0.8167	0.8028	0.8032	0.8091	0.8002	0.806	0.815

RAI 4.7.2-2

A number of Mark I containments have experienced corrosion inside their drywells at the junction of the bottom concrete floor and the steel shell. The applicant is requested to provide information regarding corrosion of the drywell shell at this location or any other location of the drywell inside surfaces.

Response:

Oyster Creek has not experienced corrosion on the inside surfaces of the drywell shell including the junction of the bottom concrete floor and the steel shell. The inside of the drywell is coated with Carbo-Zink 11 over an SSPC-SP6/SP5, commercial abrasive blast surface preparation to a dry film thickness of 3-6 mils]

Visual inspections conducted in accordance with ASME Section XI, Subsection IWE have not identified recordable corrosion at the junction of the bottom concrete floor and the steel shell or any other location inside the drywell. Minor surface rust has been noted in some areas where the coating is damaged or removed for UT measurements. The minor surface rust is limited to isolated areas and does not impact the intended function of the drywell.

RAI 4.7.2-3

Leakage from the refueling seal has been identified as one of the reasons for accumulation of water and contamination of the sand-pocket area. The refueling water passes through the gap between the shield concrete and the drywell shell in the long length of inaccessible areas. As there is a potential for corrosion in this area, Subsection IWE of the ASME code would require augmented inspection of this area. The applicant is requested to provide a summary of inspections performed (visual and NDE) and mitigating actions taken to prevent water leaks from the refueling seal components.

Response:

The refueling seals at Oyster Creek consist of stainless steel bellows. In mid to late 1980's GPU conducted extensive visual and NDE inspections to determine the source of water intrusion into the seismic gap between the drywell concrete shield wall and the drywell shell, and its accumulation in the sand bed region. The inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested using helium (external) and air (internal) without any indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in a concrete trough below the bellows. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the seismic gap (see Fig.-2). The drain line has been checked before refueling outages to confirm it is not blocked.

The only other seal is the gasket for the reactor cavity steel trough drain line (see Fig.-2). This gasket was replaced after the tests showed that it was leaking (see Fig. –2). However the gasket leak was ruled out as the primary source of water observed in the sand bed drains

because there is no clear leakage path to the seismic gap. Minor gasket leak would be collected in the concrete trough below the gasket and would be removed by the drain line similar to leaks from the refueling bellows.

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

Oyster Creek is currently committed to monitor the sand bed region drains for water leakage. A review of plant documentation did not provide objective evidence that the commitment has been implemented since 1998. Issue Report #348545 was issued in accordance with Oyster Creek corrective action process to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future, including during the period of extended operation.

Oyster Creek is committed to performing augmented inspections of the drywell in accordance with ASME Section XI, Subsection IWE. These inspections consist of UT examinations of the upper region of the drywell and visual examination of the protective coating on the exterior of the drywell shell in the sand bed region. The visual inspection of the coating will be supplemented by UT measurements from inside the drywell once prior to entering the period of operation, and every 10 years thereafter during the period of extended operation. With regards to previously performed visual and NDE inspections, refer to RAI 4.7.2-1(a).

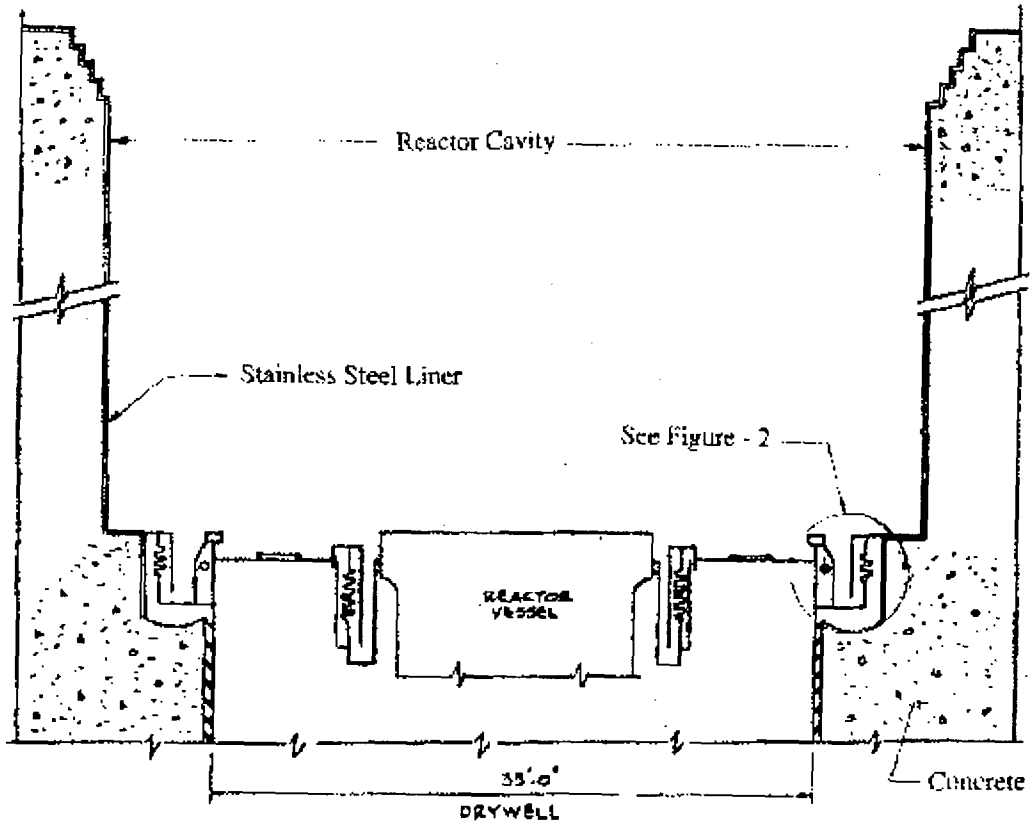


Figure 1 - Drywell and Reactor Cavity Section

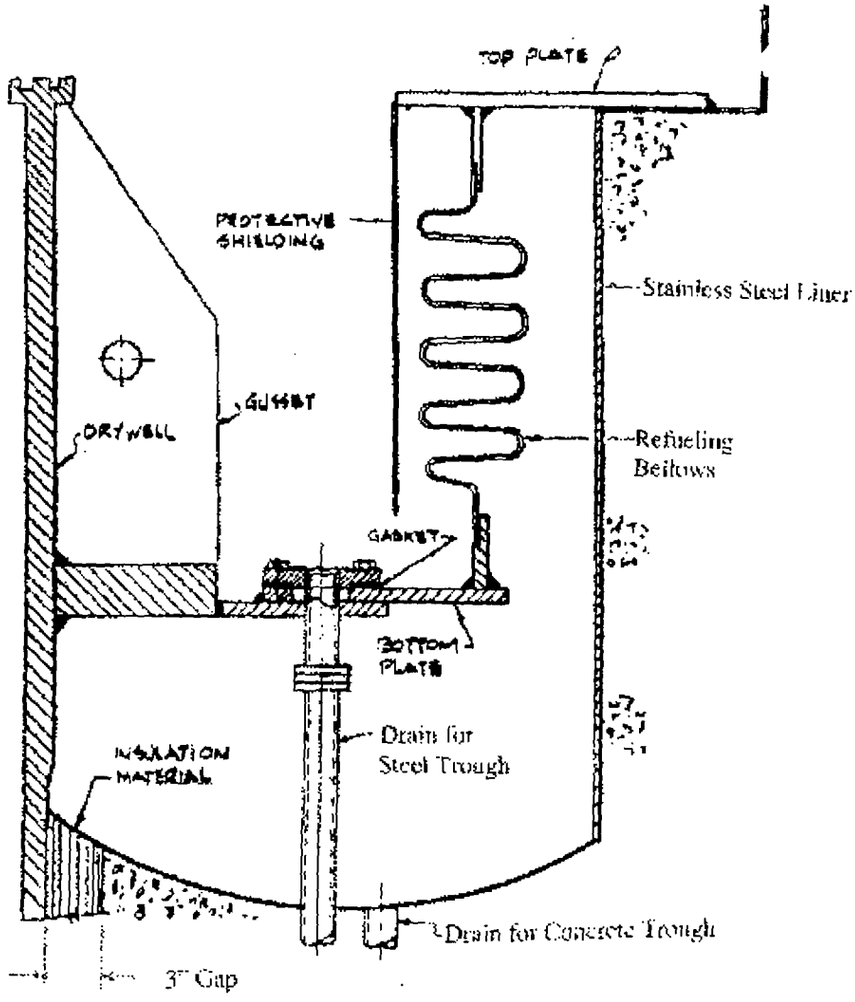


Figure 2 - Drywell to Reactor Cavity Seal Detail

RAI 4.7.2-4

Industry wide operating experience indicated a number of incidences of torus corrosion in Mark I containments. Neither LRA Table 3.5.2.1.1 nor AMP B.1.27 describes operating experience related to corrosion of the torus. The staff request the applicant to provide a summary of the results of IWE inspections performed on the torus, and a description of torus condition.

Response:

A review of industry operating experience has confirmed that corrosion has occurred in containment shells. NRC Information Notice (INs) 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. A review of plant operating experience at Oyster Creek shows that corrosion degradation has occurred in the suppression chamber (torus) and vent system. The Oyster Creek ASME Section XI, Subsection IWE aging management program, and the Protective Coating Monitoring and Maintenance Program, have identified and are managing the degradation.

Background/Chronology:

The Oyster Creek torus was designed without a corrosion allowance (0.385" nominal thickness). Prior to construction of the torus, the carbon steel segments were given a shop coat of red lead primer and transported to the site. After assembly, the structure was touched up with a red lead primer coating and a phenolic epoxy "belly-band" coating was applied at the liquid-vapor interface. Inspections of the torus interior from original startup through 1977 showed that the red lead primer on the torus shell in the vapor space region was in satisfactory condition. However, inspections conducted during the 7th refueling outage (1977) showed extensive pinpoint rusting under the red lead primer in the area above the epoxy belly-band coating. Pitting of local areas was also observed below the epoxy belly-band coating. In both cases, the corrosion was attributed to contaminants in the torus water. The pinpoint rusting above the epoxy coating was the result of an actual water/vapor interface located above the belly-band. This was corrected by broadening the belly-band coating by 10 inches. The identified pitting was weld repaired and a fresh coat of red lead primer was applied where needed.

As a result of the 1977 inspection, it was determined that the red lead primer coating had a limited ability to protect the carbon steel against corrosion attack. In addition to the lead primer, sodium chromate had been utilized in the torus water as a corrosion inhibitor. In a 1981 report prepared by the GPU Nuclear Materials Technology Section, it was recommended that all torus water impurities, including chromates due to the uncertainty of their behavior on reactor core austenitic steels following a safety injection, be removed and an epoxy coating be applied to the immersion and vapor phase regions of the torus to mitigate corrosion.

During the 10th refueling outage (1983-84), Mark I Containment modifications were made to the Oyster Creek Torus. During this outage, the torus interior surfaces, the interior of the vent system up to the drywell and all external surfaces of the vent system were grit blasted to SSPC-10 or SSPC-5 at 1 1/2 - 3 mils profile. Inspections revealed pitting corrosion on the inside

surface of the torus shell below the waterline. No visible corrosion was observed on the portion of the shell above the waterline. The corroded areas and depths of corrosion were documented for each bay. Repair criteria were developed to provide margin based on Mark I program stress analysis results. No credit was taken for other potential sources of margin (e.g., actual material properties of the plate, actual plate thickness, and permissible ASME Code undertolerance on plate thickness). A repair criterion based on acceptable metal loss due to pitting corrosion was established. Weld repair was performed if the average effective metal loss due to pitting corrosion exceeded these depths. Thus, these metal losses represent the maximum allowable metal loss that may have been left in the torus shell following the 1983 inspections and repairs:

Torus Shell Region	Acceptable Metal Loss Due to Pitting Corrosion (inch)
General Shell	0.040
Within 1" of Ring Girder	0.050
1"-8" Away from Ring Girder	0.080
Within 1" of Saddle Weld	0.035
1"-8" Away from Saddle Weld	0.090

Pitted surfaces of the immersed torus shell requiring repair were repaired by weld overlay. Pitted surfaces where repair was not required were filled with Mobil 46-X-16 Epoxy prior to recoating. Surfaces in the vent system thinned by corrosion were repaired by weld overlay. Rough areas of the torus shell were blended by grinding. The immersion portion of the torus shell, the interior of the downcomer and the entire interior surfaces of the vent system were given 3 coats of Mobil 78 Hi-Build Epoxy (DFT-16 mils). The vapor phase portion of the torus shell, exterior of the vent header and vent lines portions inside the torus were given two coats of Mobil 78-Hi Build epoxy (DFT-10 mils). Following coating application, the entire torus interior was heat cured at 108°F for 48 hours. Demineralized water was put back in the torus. No coating was applied to the exterior surface of the torus shell at that time.

During the 11th refueling outage (1986), a Material Nonconformance Report (MNCR 86-285) identified general corrosion on the outside surface of the torus shell. Wall thickness measurements were taken to determine the metal loss due to the observed corrosion. The corrosion was categorized as uniform and superficial with no evidence of rust scale. No appreciable metal loss was associated with this condition (i.e., the loss was estimated to be no more than 2 mils). Also in 1986, analysis MPR-953, "Torus Shell Thickness Margin" was performed to determine a corrosion allowance for the torus shell based on the as-left condition of the torus following the 1983 shell repairs. The scope of the analyses included:

- Review of Mark I containment torus stress analysis results to determine the minimum thickness for which the torus shell would meet ASME Code allowable stress values. This included formally documenting the analyses and corrosion allowance criteria used.

- Review of manufacturers' material certificates to determine actual plate thickness and strength.

- Determination of underthickness tolerance permitted by the ASME Code.

- Review of the 1983 GPUN torus inspection reports to determine the maximum depths of pitting corrosion which were not weld repaired.

Torus shell thickness margins were determined based on calculated stresses, actual material properties, actual plate thicknesses, and ASME Code permitted undertolerance. It was concluded that the calculated stress margin alone exceeded the maximum corrosion depth left in the torus shell for all regions of the torus and that the difference between the stress margin and maximum corrosion depth could be considered a corrosion allowance. The following table summarizes the results of the analysis.

Torus Shell Location	Thickness Margin Based on Mark I Program Stress Requirements (inch)	Material Property Margin (inch)	Plate Thickness Margin (inch)	ASME Code Undertolerance (inch)	Maximum Depth of Corrosion Left in Torus Shell After 1983 Repairs (inch)
General Shell	0.060	0.013	0	0.010	0.040
Within 1" of SRV Supporting Ring Girders	0.061	0.013	0	0.010	0.050
Within 1" of Non-SRV Supporting Ring Girders	0.079	0.013	0	0.010	0.050
Between 1"-8" Away From All Ring Girders	0.103	0.013	0	0.010	0.040
Within 1" of Saddle Flange	0.060	0.013	0	0.010	0.035
Between 1"-8" Away From Saddle Flange	0.151	0.013	0	0.010	0.040
Within 1" of Torus Straps	0.057	0.013	0	0.010	0.040
Remaining Portion of Shell Between Torus Straps	0.060	0.013	0	0.010	0.040

In 1988, a coating system consisting of two (2) coats was applied to the outside surface of the torus shell. The first coat was a penetrating primer (1-1/2 to 2 mils DFT) designed to impregnate and tie up loose rust (Devoe-Napko Pre-Pime 467 Rust Penetrating Sealer No. 467-K-9920). The second coat was Chemfast 100 primer (3 to 10 mils DFT) manufactured by Devoe-Napko Corporation.

To assure coating integrity, periodic inspections of the torus interior have been performed since the coating was first applied in 1983. A review of past inspections of the torus shell and the vent system indicates that the majority of the problems found have been attributed to blistering of the coating and localized pitting. The following provides an "Executive" level summary of the results of these inspections:

- 11th refueling outage (1986): The inspection consisted of a visual examination of the vapor space region and shell surface at the water line. No coating damage or evidence of corrosion was observed.

- 12th refueling outage (1988-1989): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. The coating in the vapor space was in excellent shape. No tests were performed to quantify the condition of the coating in this area. The inspection focused on the immersion region using divers qualified to perform detailed coating and corrosion assessment. The inspection revealed a blistering condition in the coating at the torus invert and areas of minor mechanical damage. It was determined that the blistering condition occurred where the 46-X-16 epoxy filler had been used to fill pits that did not require weld repair prior to torus coating in 1983. These blisters were observed on all the 20 bays to a varying degree. It was suspected that the 46-X-16 material never achieved full cure and was softened by immersion in the torus and by reaction with the solvents contained in the Mobil 78 topcoats.

  The three most severely blistered bays (bays 6, 7, and 9) were identified for future inspections. Three one foot square test patches were established in bays 6 and 7. The test patches were outlined with the Brutem 15 repair coating. The size and degree of frequency of the blisters within each test patch were recorded as a baseline for comparison against future inspection results.

  Adhesion tests using a vacuum box were conducted on blisters, and elcometer (an instrument used to measure coating adhesion in psi) and putty knife adhesion tests were conducted on the unblemished coating. Results were evaluated and maintained for future comparison.

  Corrosion attack under nonfractured blisters was minimal and limited to surface discoloration. A portion of the fractured blisters examined exhibited small (less than 1/32" dia.) pits on the substrate. Loss of base metal in the affected areas was no greater than 0.002". One area inspected in bay 5 revealed deep pitting in the range of 15 to 50 mils in depth. However, the general condition of the steel did not show signs of recent corrosion. The steel surface was shiny with evidence of the previous surface prep observable. Some of the deepest pits held residue of the 46-X-16 epoxy filler. It was concluded that the pitting observed was documented and coated over during the coating operation in 1984. Fractured blisters exposing substrate were repaired using Brutem 15.

  Four (4) UT shell thickness readings were taken adjacent to a 0.058" pit located in bay 10. The minimum shell thickness recorded was 0.387".

Minor mechanical damage (e.g., abrasion) was also observed. Areas exhibiting pitting were limited to mechanical damage that completely exposed the substrate. These areas were repaired using Brutem 15. The maximum pit depth measured at the areas of mechanical damage was 30 mils.

- 13th refueling outage (1991): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. The objective of the inspection was to assess the coating condition by repeating the same series of tests performed in bays 6, 7, and 9 during the 12th refueling outage. The three one foot square test patches in bays 6 and 7 were also inspected. The inspection was expanded to include visual examination of the vent header system and inspection of blistered coating near the torus invert in bays 5, 10, and 11.

  All the adhesion tests conducted in the12th refueling outage were repeated to allow for direct correlation between the two sets of data. It was concluded that the adhesion qualities measured in the 12th refueling outage did not change.

  The blistered condition found in the 12th refueling outage was stable (blister count data of the test patches indicated no significant change had occurred between the 12th and 13th refueling outages). The inspection of the substrate under intact blisters after removal of the blister cap identified slight discoloration and pitting with pit depths of less than 0.001". Light wire brushing by hand easily removed the magnetite deposit leaving bright metal prior to coating repair. Visual observations and pit depth measurements indicated that corrosion underneath broken blisters was also minimal. The substrate beneath fractured blisters exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

  Pit depth readings and/or ultrasonic thickness measurements were taken in bays 5, 6, 7, 9, 10, and 11. No pitting in excess of 0.030" was identified in bays 9, 10, and 11. Several pits in the range of 0.010" to 0.041" were observed in bay 5. UT shell thickness readings taken in bay 5 near pitted areas ranged from 0.390" to 0.400". Several pits in the range of 0.003" to 0.050" were observed in bay 6. UT shell thickness readings taken in bay 6 near pitted areas ranged from 0.380" to 0.400". Several pits in the range of 0.014" to 0.035" were observed in bay 7. UT shell thickness readings taken in bay 7 near pitted areas ranged from 0.400" to 0.420". It was noted that the deepest pits in these bays held residue of 46-X-16 indicating that these pits were evaluated as acceptable and coated over as part of the torus coating effort in 1984.

  In the vent header system, the general condition of the coating appeared good. Blistering, pinpoint rusting, and mechanical damage to the coating was minimal. Visual observation and pit depth measurements showed minor pitting corrosion (less than 0.010") on substrate in the immersion area. Blister caps were removed from sample intact blisters in the immersion area. The exposed substrate exhibited no sign of corrosion attack.

  The coating areas repaired with underwater epoxy (Brutem 15) during the previous (12th) refueling outage appeared in excellent condition.

- 14th refueling outage (1992-1993): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. Inspections were performed in the immersion portion of torus bays 1 through 10, in the torus vapor space, and in the vent header to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. Inspection activities included qualitative visual inspection of the submerged portion of the torus in all ten bays, and, in the vapor region and vent header to document the location and extent of coating defects and resultant corrosion. Qualitative inspections included the evaluation of blisters. Inspection activities also involved quantitative inspections including depth measurements of pitting corrosion in selected bays, the evaluation of test patches established during the 12th refueling outage, vacuum box testing of areas, peel tests, adhesion tests, and removal of blister caps with the evaluation of substrate.

  In the immersion region of the torus, blister count and quantity of fractured blisters had "moderately" increased. Coating adhesion and integrity were comparable to previous inspections. The removal of intact blister caps indicated that the coating system was still providing an effective corrosion barrier. A total of three quantitative pit depth measurements were taken. Three pits were identified with total metal loss values of 0.0215 (bay 6), 0.0325 (bay 7), and 0.0685 (bay 2) inches. Wall thickness measurements immediately adjacent to these areas revealed adequate remaining wall thickness (0.38" to 0.40"), which indicated that these areas are extremely localized in nature. All pits were repaired using UT #15 epoxy coating.

  In the vapor region, no blistering or pitting corrosion was identified. In the vent header, the majority of the blisters identified were in the lower areas of the caps at the intersection of the vent header and vent line where water was present. Defects identified were minor in nature and distribution.

The above summary of inspections performed through the 14th refueling outage was provided to the NRC in a revised response to an RAI associated with TSCR No. 216 (Technical Specification Change Request to increase the Electromagnetic Relief Valves (EMRV) setpoints). In that response, GPUN concluded that, based on the coating inspections performed to date, "the torus shell thickness is virtually unchanged since the repair and coating effort in 1983." Additionally, no new pitting or general corrosion was found during the subsequent inspections performed since 1983, and, data collected to date provided a high confidence level that the coating material was adequately adhering to the shell and providing corrosion protection. In the NRC SER related to Amendment No. 177, the staff found the explanations provided to be acceptable provided GPUN continue its coatings monitoring and maintenance program.

GPUN's 1994 submittal of TSCR No. 216 to increase the setpoint values of the EMRVs required an evaluation of the torus shell for the consequent increase in the EMRV loads. This evaluation revised the Mark I thickness margin due to the increase in EMRV loads. The following table summarizes the results of the reanalysis.

Torus Shell Location	Thickness Margin Based on Mark I Program Stress Requirements (inch)	Revised Mark I Thickness Margin Due to Increase in EMRV Loads (inch)
General Shell	0.060	0.047
Within 1" of SRV Supporting Ring Girders	0.061	0.048
Within 1" of Non-SRV Supporting Ring Girders	0.079	0.067
Between 1"-8" Away From All Ring Girders	0.103	0.092
Within 1" of Saddle Flange	0.060	0.047
Between 1"-8" Away From Saddle Flange	0.151	0.142
Within 1" of Torus Straps	0.057	0.044
Remaining Portion of Shell Between Torus Straps	0.060	0.047

- 15th refueling outage (1994): No underwater coating inspections performed.

- 16th refueling outage (1996): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. A detailed qualitative inspection of the torus shell and internals was performed in bays 6, 7, 9 and 11 through 20 to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. Overall, no significant failure or problems concerning the integrity of the coating system in the immersion region were identified. Coating defects identified included blistering, rust stains, isolated areas of pinpoint rusting and mechanical damage of the coating. Immersion region coating repairs were performed as required using UT #15 epoxy coating.

  Inspection activities in the immersion region also involved quantitative inspections including the evaluation of test patches established during the 12th refueling outage, vacuum box testing, peel tests, adhesion tests (also performed for vapor space region), and removal of blister caps with the evaluation of substrate. Blister count and quantity of fractured blisters had moderately increased. Coating system adhesion and integrity were comparable to previous inspections. Removal of blister caps indicated the coating system was still providing an effective corrosion barrier. There were no areas of pitting corrosion identified. UT wall thickness measurements taken in bay 6 indicated that the measured thickness of 0.394 to 0.404" exceeded the nominal thickness of 0.385".

Inspections performed in the vent header and vapor space region of the torus yielded no significant findings. Coating defects identified included blistering (vent header only), rust stains, isolated areas of pinpoint rusting and mechanical damage of the coating. Minor coating repair was performed in the vent header and at adhesion test areas of the vapor space region.

Repairs made with Brutem-15 and UT#15 during previous outages continued to perform well with no indications of failure or weakness. No rework was required on previous repair areas.

Based on the results of the inspections performed during the outage and comparison to previous outage findings, it was concluded that periodic maintenance using underwater coating inspection and repairs was providing proper and adequate protection to the torus coating system.

- 17th refueling outage (1998): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. Outage scope included ECCS pump suction strainer replacement. A qualitative visual inspection of the torus shell was performed in all 20 bays to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. As reported during previous inspections, dense blistering was present on the lower pressure boundary invert. It was noted that little growth in the size or population density of the blisters had occurred over the past 10 years. Broken blisters were the most commonly occurring coating deficiency identified which resulted in corrosion. A total of 223 broken blisters were found throughout the immersion area (mostly attributed to underwater radiation survey probes used during ECCS suction strainer replacement activities). Areas of minor mechanical damage were also identified. There were no areas of pitting corrosion identified. Underwater coating repairs using UT#15 epoxy coating were performed on 100% of the coating deficiencies that resulted in corrosion on the torus shell immersion area.

  Based on the results of the inspections performed during the outage and comparison to previous outage findings, it was concluded that periodic maintenance using underwater coating inspection and repairs was providing proper and adequate protection to the torus coating system.

- 18th refueling outage (2000): No underwater coating inspections performed.

- 19th refueling outage (2002): Inspection was performed by Underwater Construction Corporation. A qualitative visual inspection of the immersed torus shell, torus vapor space, and vent header was performed in all bays to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. Qualitative and quantitative pit assessment was performed to assess corrosion rates and to document any pit that exceeded the pre-established pit depth criteria.

Coating deficiencies in the vapor space and vent header were minor. Isolated areas of mechanical damage, pinpoint rusting, and minor pitting corrosion were identified. The maximum pit depth in the vapor space was less than 0.005". Pit depths in the vent header ranged from 0.001" to 0.010". The overall condition of the vapor space and vent header coating was judged to be "good to excellent".

Coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001".

Several blistered areas included pitting damage where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate. Other coating deficiencies identified consisted primarily of spot rust, pinpoint rusting, and minor mechanical damage. Qualitative assessment of a sample of the pitting corrosion on exposed base metal indicated that pit depths overall did not exceed 0.050". Selected areas of exposed base metal representing worst case pitting corrosion were repaired using UT#15 epoxy coating.

Three quantitative pit depth measurements were taken in several locations in bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to represent typical conditions found on the shell. The identified pits where the blisters were fractured indicated that the measured pit depths (less than 50 mils) were significantly less than the criteria established in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

To further characterize the changes in blister condition, a quantitative assessment was performed on the bay 6 and 7 test patches. Blister count indicated a general increase in the formation of new blisters and in the occurrence of fractured blisters. The rates of increase appear to be decreasing with the exception of new blisters recorded on the test patch vertical and horizontal bisecting centerlines which divide the test patch into four quadrants.

As a result of the 19th refueling outage coating inspection, Underwater Construction Corporation recommended that a qualitative coating and corrosion inspection be performed during the 20th refueling outage to confirm that the condition of the coating system has not changed significantly. It was also recommended that the requirements for the frequency of underwater coating inspection and repair be based on the as-found coating condition at the next inspection.

At the request of AmerGen, the results of the 19th refueling outage coating inspection were reviewed independently by industry coating expert Jon R. Cavallo of Corrosion Control Consultants and Labs, Inc. The Cavallo assessment also included the review of previous written and photographic/video records of underwater inspections of the torus immersion region back to 1988. It was concluded that:

- the coating system continues to perform its design function to protect the underlying carbon steel substrate from corrosion,
- the amount and condition of coating blisters in the Mobil 78 Hi-Build coating material applied in 1984 over the Mobil 46-X-16 epoxy filler have remained stable since discovered in 1988,
- the coating blisters in the Mobil 78 Hi-Build coating material applied in 1984 over the Mobil 46-X-16 epoxy filler do not appear to fracture spontaneously; rather, the coating blisters fracture when mechanically stressed during desludging and other maintenance operations,
- the small areas of carbon steel substrate exposed by mechanical damage to the coating system or fracture of coating blisters corrode at a very low rate (less than 5 mpy), and,
- the repair of torus coating damage which exposes bare steel substrate can be postponed until two refueling outages (21st refueling outage).

- 20th refueling outage (2004): Based on the review of inspection data by AmerGen, and, based on the independent review of the inspection data by an industry coatings expert, no underwater coating inspections were required.
- 21st refueling outage (2006): Underwater coating inspections scheduled.

Current Torus Condition:

The current torus condition has been determined based on UT thickness measurements and pit depth measurements taken over past inspections:

	Minimum Uniform Thickness	
	Measured	Allowable (nominal 0.385" less Mark I thickness margin revised for EMRVs)
General Shell	0.343"	0.338"
Shell ~ ring girders	0.345"	0.337"
Shell ~ saddle flange	0.345"	0.338"

Shell ~ Torus straps	0.345"	0.341"

Where local pitting corrosion measurements are less than the uniform thickness requirements, local area thickness acceptance criteria has been applied.

- Criteria was established in 2002 for local thickness acceptance criteria from nominal 0.385" for the torus shell area:
  - Isolated Pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center to center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated.
  - Multiple Pits that can be encompassed by a 2-1/2" diameter circle are limited to a maximum pit depth of 0.141" provided the center to center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or recoated.
- Pitting corrosion less than or equal to 0.040" is acceptable without any size restriction since it satisfies minimum uniform thickness requirements.
- Existing pitting corrosion depths that have exceeded 0.040" were evaluated for acceptability and include:
  - 1 pit of 0.042" in Bay 1 meets local pit depth criteria (2002)
  - 1 pit of 0.0685" in Bay 2 meets local pit depth criteria (1992)
  - 2 pits of 0.050" in Bay 6 greater than 20" apart meets local pit depth criteria (1991)
  - 1 pit of 0.058" in Bay 10 meets local pit depth criteria (1988)

Conclusion:

- The Torus has been inspected, evaluated, repaired, and continuously monitored to manage the identified shell corrosion discovered in the 1970's.
- Numerous engineering evaluations and calculations exist to demonstrate that the torus thickness is meeting current design and licensing basis requirements.
- The Torus shell deficiencies are related to:

- Problems with the original coating specification (use of redlead primer)
- Improper curing of the improved replacement coating from 1983.

- The blisters will typically remain intact unless broken by mechanical force or agitation.

- Structural Integrity of the Torus will not be adversely impacted if the pit dimensions remain within established acceptance criteria and the coating on top of the localized pit is properly repaired in a timely manner.

- Proper maintenance of the coating performed every other refueling outage will ensure that there are no aging effects / mechanisms associated with the structural integrity of the Torus.

RAI 4.7.2-5

Drywell corrosion is a safety concern; therefore, the staff believes that the updated final safety analysis report (UFSAR) supplement should, at a minimum, briefly describe the quantitative aspect of the drywell corrosion, and applicant's assertions to maintain it above a certain thickness to ensure that the containment could performs its intended function during the period of extended operation. The TLAA and Subsection IWE of the ASME code are the procedures by which it will maintain the containment functionality. The staff requests the applicant to address this matter.

Response:

UFSAR Section 3.8.2.8, Drywell Corrosion, provides historical information on drywell corrosion and corrective actions taken to control it. The section also describes aging management activities that are implemented during the current term consistent with existing NRC commitments. The section is revised periodically to include, by reference, the results of quantitative engineering analyses, the UT measurements in the upper regions of the drywell, and inspection of the coating of the drywell shell in the sand bed region.

Appendix A.1.27 ASME Section XI, Subsection IWE, and A.5 license renewal commitment list, item number 27, which are included in the application will be incorporated in the UFSAR as a supplement. However, both Appendix A and A.5 commitment list do not include additional commitments to the NRC Staff on drywell corrosion for the period of extended operation. The A.5 commitment list will be revised to include details of these additional commitments and will be the basis for the drywell corrosion aging management program during the period of extended operation. The revised A.5 commitment list and Appendix A.1.27 will be incorporated in the UFSAR. The supplement therefore will include elements of the drywell corrosion aging management program in sufficient detail to ensure that program commitments are documented in the UFSAR.

References:

1. Letter from J. A. Zwolinski (NRC) to P. B. Fiedler (GPU), Interim Operation for Cycle 12 following corrosion of the outer surface of the drywell shell, dated December 29, 1986.
2. Letter from J. C. DeVine (GPU) to U.S. NRC, Oyster Creek Drywell Containment, dated May 26, 1992.
3. Oyster Creek UFSAR Section 3.8.2.8, Drywell Corrosion
4. Meeting Minutes of November 13, 1987, Meeting with GPU Nuclear Corporation to Discuss Matters Related to Oyster Creek Drywell Corrosion.
5. TDR No. 1027, Design of UT Inspection Plan for the Drywell Containment Using Statistical Interference Methods.
6. Letter from J.C. Devine, Jr. (GPU) to U. S. NRC, Oyster Creek Drywell Containment, dated November 26, 1990.

ATTACHMENT 1

(GPU Letter to NRC dated November 26, 1990)

ATTACHMENT 2

(GPU Letter to NRC dated March 4, 1991)

ATTACHMENT 3

(GPU Letter to NRC dated January 16, 1992)

NRC Information Request Form

Item No	*Date Received:*	*Source*
AMR-164	10/31/2005	AMR Audit
Topic:	*Status:*	Closed

Inaccessible Portion of the Drywell Shell

Document References:
3.5.2.2.1

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

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

Assigned To: Ouaou, Ahmed

Response:

The embedded portion of the drywell shell is exempt from visual examination in accordance with IWE-1232. Pressure testing in accordance with 10 CFR Part 50 Appendix J, Type A test, is credited for managing aging effects of inaccessible portions of the drywell shell consistent with NUREG-1801.

NUREG-1801 Vol. 2 Item Number II.B1.1-2, Aging Management Program (AMPs) column states that loss of material due to corrosion is not significant if the following conditions are satisfied:

"Concrete meeting the specifications of ACI 318 or 349 and the guidance of 201.2R was used for containment shell or liner. The concrete is monitored to ensure that it is free of cracks that provide path for water seepage to the surface of the containment shell or liner. The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements. Water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

If any of the above conditions cannot be satisfied, then a plant-specific aging management program for corrosion is necessary."

AMR results concluded that Oyster Creek satisfies the above requirements and a plant-specific aging management program is not required for corrosion of the embedded drywell shell. The Oyster Creek concrete meets the requirements of ACI 318 and the guidance of ACI 201.2R. The drywell concrete floor will be monitored for cracks under the Structures Monitoring aging management program (B.1.31). Oyster Creek design does not include a moisture barrier. However the design provides a

NRC Information Request Form

9" high curb (min) around the entire drywell floor (except at the two trenches discussed below) to prevent any water accumulated on the floor from being in contact with the drywell shell. The curb is considered part of the drywell concrete floor and inspected for cracking under the Structures Monitoring Program (B.1.31). The drywell floor is designed to slope away from the drywell shell towards the drywell sump for proper drainage. The sump level is monitored in the main control room in accordance with Technical Specifications, and actions are taken to ensure Technical Specifications limits are not violated. Should the sump fill and overflow leak rate cannot be monitored and a plant shutdown will be required to regain leak rate monitoring capability and determine the source of the leak.

During the investigative period to determine the extent of corrosion in the exterior surfaces of the sand bed region, two trenches were excavated in the drywell concrete floor. The purpose of the trenches was to expose the embedded drywell shell so that UT thickness measurements can be taken from inside the drywell in the sand bed region. Visual inspection and UT measurements did not identify corrosion as a concern on the exposed embedded drywell shell inside the drywell within the excavated trenches. The two trenches were sealed with an elastomer to prevent water intrusion into the embedded shell.

Prior to entering the period of extended operation a one-time visual inspection of the embedded drywell shell, within the two trenches, will be performed by removing the sealant and exposing the embedded shell. If visual inspection reveals corrosion that could impact drywell integrity, corrective actions will be initiated in accordance with the corrective action process to ensure that the drywell remains capable of performing its intended function. Following these inspections, the trenches will be resealed to continue protecting the embedded shell.

The inaccessible drywell shell in the sand bed region became accessible after removal of sand in 1992. The interface of the shell and the sand bed floor was cleaned, coated, and sealed with silicon sealant. The periodic coating inspection has not identified any coating degradation at the shell/concrete interface that would indicate that corrosion is occurring in the embedded portion of the shell.

Clarified the commitment for inspecting the embedded shell inside the drywell. (AMO 4/1/06)

Supplemental Information - 04/19/2006

As discussed above, Oyster Creek committed to perform one-time visual inspection of the embedded drywell shell, within the two trenches, by removing the sealant and exposing the embedded shell. Inspection and acceptance criteria will be in accordance with IWE. In addition, one-time UT measurements will be taken and corrective actions will be initiated in accordance with the corrective action process to ensure that the drywell remains capable of performing its intended function.

LRCR #: 229 ***LRA A.5 Commitment #:***

IR#:

NRC Information Request Form

Approvals:

Prepared By:	Ouaou, Ahmed	4/19/2006
Reviewed By:	Muggleston, Kevin	4/19/2006
Approved By:	Warfel, Don	4/19/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No	*Date Received:*	*Source*
amr-164	9/20/2005	S&S Meth Audit

Topic: *Status:* Closed

Scoping Methodology for NSR/SR piping

Document References:

NRC Representative Tingen, Steve

AmerGen (Took Issue): Ouaou, Ahme

Question

The scoping methodology for non-safety related piping attached to safety related piping (10 CFR 54.4 a(2)) identifies 6 criteria that can be used to establish an anchor. Provide a count of how many cases as associated with each criterion. The count need not be exact. Specifically,

1. Number of three mutually perpendicular restraints
2. Number of major equipment (pumps, heat exchangers..)
3. Number of penetrations
4. Number of Underground (buried)
5. Number of flexible hoses or joints
6. Number of cases for end of the piping run

Assigned To: Ouaou, Ahmed

Response:

The number of non-safety related piping to safety related piping interfaces & credited supports is summarized below. The information was given to Steve Tingen in a table format identified by applicable LR drawing.

1. Number of three mutually perpendicular restraints = 9
2. Number of major equipment (pumps, heat exchangers..) = 24
3. Number of penetrations = 13
4. Number of underground (buried) = 0
5. Number of flexible hoses or joints = 5
6. Number of cases for end of the piping run = 67

LRCR #: *LRA A.5 Commitment #:*

IR#: 05

Approvals:

Prepared By: 9/22/2005

NRC Information Request Form

Reviewed By: Muggleston, Kevin 9/22/2005

Approved By:

NRC Acceptance (Date): 9/21/2005

NRC Information Request Form

Item No
amr-164

Date Received: 9/20/2005

Source AMR Audit

Status: Closed

Topic:
Maintenance Rule - Combustion Turbines

Document References:

NRC Representative Talbot, Frank

AmerGen (Took Issue): Warfel, Dom

Question

How is the combustion turbine treated in terms of the Maintenance Rule.

Assigned To: May, Mike

Response:

The CTs are included with SBO electrical connection equipment in the Maintenance Rule as the Station Blackout (SBO) CT and Support systems.
No additional maintenance or testing requirements for the CTs based on performance as monitored by the Maintenance Rule.
The Maintenance Rule for Station Blackout (SBO) CT and Support systems did not identify any new intended functions for the (SBO) CT system. The intended function as identified in both the LRA and in the Maintenance Rule is to perform a function that demonstrates compliance with the regulations for Station Blackout (10CFR 50.63 - Loss of all AC power).

LRCR #: *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: 9/21/2005

Reviewed By: Spamer, Deb 9/22/2005

Approved By:

NRC Acceptance (Date):

GPU NUCLEAR

CALCULATION COVER SHEET
(Ref. EP-006)

Subject: C-1302-187-8610-030	Calculation No.	Rev. No. 1	System Nos. 243	Sheet 1 of 1

1. Is this calculation within the scope of the GPUN Operational Quality Assurance Plan? (If **YES**, a verification is required unless the calculation is a non-substantive revision.) ☒ Yes ☐ No

2. Does this calculation contain assumptions / design inputs that require confirmation? (If **YES**, provide CAP or appropriate configuration control number(s)) (e.g., ECD, PFU, MD, PCR, etc.) _____ ☐ Yes ☒ No

3. Does this calculation require revision to any existing documents? (If yes, provide CAP or appropriate configuration control number(s)) _____ ☐ Yes ☒ No

4. Is this calculation performed as a design basis calculation? (If **YES**, identify design basis parameters.) (See Section 3.3) ☐ Yes ☒ No

   Parameter: _____

Referenced Calculations and Safety Evaluations (See Section 4.3.1.3)	Rev. No.
See Section 3.0 of the subject calculation	0
3.7 GPUN Calculation C-1302-187-5300-005	0
3.11 GPUN Calculation C-1302-187-5300-008	0
3.13 GPUN Calculation C-1302-187-5300-015	0
3.14 GPUN Calculation C-1302-187-5300-017	0
3.16 GPUN Calculation C-1302-187-5300-020	0
3.17 3.17 GPUN Calculation C-1302-187-5300-021	0
3.18 GPUN Calculation C-1302-187-5300-022	0
3.19 GPUN Calculation C-1302-187-5300-025	0
3.20 GPUN Calculation C-1302-187-5300-024	0
3.21 GPUN Calculation C-1302-187-5300-028	0

Comments: Only change was to add references. No need to perform design verification. Original design verification is unchanged.

APPROVALS

Originator Hassan Elrada	Date 7/12/2000
Verification Engineer/Reviewer	Date
Section Manager Nick Trikouros	Date 7/12/2000
Other Verification Engineer/Reviewer	Date
Other Verification Engineer/Reviewer	Date

N5870 (10/99)

GPU NUCLEAR	DOCUMENT NO.
	C-1302-187-8610-030

TITLE: Statistical Analysis of Drywell Thickness Data thru September 1996

REV	SUMMARY OF CHANGE	APPROVAL	DATE
1	Revised Section 3.0 to include a list of the mainframe computer files used to generate this calculations. Added references 3.22, 3.23, 3.24 and 3.25.	[illegible]	7/12/2000
		[illegible]	7/12/2000

1.0 PROBLEM STATEMENT

The basic purpose of this calculation is to update the thickness measurement analyses documented in References 3.7, 3.8, and 3.11 thru 3.21 by incorporating the measurements taken in September 1996.

Specific objectives of this calculation are:

(1) Determine the mean thickness at each of the monitored locations.

(2) Statistically analyze the thickness measurements to determine the corrosion rate at each of the monitored locations.

2.0 SUMMARY OF RESULTS

The remainder of the sand and the corrosion products were removed from the sand bed during the 14R refueling outage which commenced in November 1992. The outside surface was cleaned and coated at that time. This represents such a major change in the environment that analysis of the ongoing corrosion rates in the sand bed cannot be statistically meaningful. However, the analyses were performed as though this change had not taken place. The period covered in these analyses in the sand bed commences in February 1990 when leakage through the pool liner was significantly reduced. Only one sand bed bay indicates a significant corrosion rate. Bay 11A has a calculated rate of -6.0 ±2.0 mils per year, compared to 14.3 ±3.1 through December 1992, -12.3 ±3.0 prior to February 1990 and -10.5 ±2.2 through September 1994. The sand bed bays where measurements have been taken on a 7-point strip do not show significant corrosion rates.

Analyses of the monitored points at elevations above the sand bed do not indicate any statistically significant ongoing corrosion. The corrosion rates at these elevations are computed using all available data.

The results of the calculation are summarized in the following tables. The terms used are defined below.

(1) Best Estimate Corrosion Rate

- With three or more data points, this is the slope of the regression line.
- For only two data points, this is the slope of the steepest line which can be drawn within the ± one-sigma interval about the two measurements.

(2) 95% Upper Bound Corrosion Rate

The corrosion rate for which we have 95% confidence that it is not being exceeded. At least four data sets are required to make a meaningful estimate of this value.

(3) **Best Estimate Mean Thickness**

- When the regression is statistically significant (F-Ratio is 1.0 or greater) and the slope is negative, this is the predicted value ± standard error from the regression for the date of the last measurement.

- When the regression is not statistically significant (F-Ratio less than 1.0) and/or the slope is positive, this is the grand mean of all the data ± standard error.

- For the sand bed, this is the grand mean of all the data since 1992 ± standard error.

(4) **Measured Mean Thickness**

The mean ± standard error of the valid data points from the most recent set of measurements.

(5) **F-Ratio**

- An F-Ratio less than 1.0 occurs when the amount of corrosion which has occurred since the initial measurement is less than the random variations in the measurements and/or fewer than four measurements have been taken. In these cases, the computed corrosion rate does not necessarily reflect the actual corrosion rate, and it may be zero. However, the confidence interval about the computed corrosion rate does accurately reflect the range within which the actual corrosion rate lies at the specified confidence level.

- An F-Ratio of 1.0 or greater occurs when the amount of corrosion which has occurred since the initial measurement is significant compared to the random variations, and four or more measurements have been taken. In these cases, the computed corrosion rate more accurately reflects the actual corrosion rate, and there is a very low probability that the actual corrosion rate is zero. The higher the F-Ratio, the lower the uncertainty in the corrosion rate.

- Whereas an F-Ratio of 1.0 or greater provides confidence in the historical corrosion rate, the F-Ratio should be 4 to 5 if the corrosion rate is to be used to predict the thickness in the future. To have a high degree of confidence in the predicted thickness, the ratio should be at least 8 or 9.

(6) **N**

The number of data sets used in the analysis.

(7) **Years**

The time span between the first and last of the analyzed data sets.

2.1 Sand Bed Region 7 x 7 Grids Using Data From February 1990 through September 1996

Bay & Area	Corrosion Rate, mpy		Mean Thickness, mils		F-Ratio (5)	N(6)	Date Span yrs (7)
	Best Est.(1)	95% (2)	Best Est. (3) *	Measured (4)			
9D	-0.8 ± 1.3	-3.2	1001.2 ± 4.8	1007 ± 10.6	< 0.1	9	6.6
11A	-6.0 ± 2	-9.8	825.1 ± 2.7	829.7 ± 9.1	1.7	9	6.6
11C Top	+7.3 ± 3.3	+1.1	998.4 ± 22.1	1041.8 ± 21.4	0.9	9	6.6
11C Bot	+1.4 ± 1.9	-2.2	864.1 ± 9.8	883.0 ± 7.4	0.1	9	6.6
13A	-1.1 ± 1.1	-3.2	838.6 ± 5.5	843.4 ± 7.4	0.2	10	6.6
13D Top	-0.6 ± 3.2	-6.7	1050.5 ± 6.7	1059.3 ± 11.2	<0.1	8	6.4
13D Bot	+3.6 ± 2.5	-1.3	911.4 ± 11.2	933.0 ± 9.6	0.4	8	6.4
15D	+1.6 ± 1.3	-0.8	1058.8 ± 3.8	1065.0 ± 8.5	0.3	9	6.6
17A Top	-0.3 ± 0.6	-1.5	1132.6 ± 5.9	1144.1 ± 11.1	<0.1	9	6.6
17A Bot	+6.7 ± 2.4	+2.0	957.3 ± 19.9	996.9 ± 10.7	1.4	9	6.6
17D	+0.9 ± 1.8	-2.6	823.9 ± 10.5	844.5 ± 8.9	<0.1	9	6.6
17/19 Top	-1.6 ± 1.4	-4.3	968.9 ± 3.8	967.4 ± 6.0	0.2	9	6.6
17/19 Bot	-0.9 ± 1.5	-3.8	987.1 ± 3.5	991.4 ± 6.3	<0.1	9	6.6
19A	+0.5 ± 0.9	-1.2	807.1 ± 4.3	814.9 ± 10.0	<0.1	9	6.6
19B	-1.9 ± 1.2	-4.2	833.7 ± 4.8	837.4 ± 9.5	0.5	9	6.6
19C	+1.6 ± 1.7	-1.7	829.0 ± 9.5	848.0 ± 11.1	0.2	9	6.6

* Since 12/8/92

2.2 Sand Bed Region 1 x 7 Grids Using Data From February 1990 through September 1996

Bay & Area	Corrosion Rate, mpy		Mean Thickness, mils		F-Ratio (5)	N(6)	Date Span yrs (7)
	Best Est.(1)	95% (2)	Best Est. (3) *	Measured (4)			
1D	-3.9 ± 1.5	-7.5	1126.1 ± 14.3	1151.0 ± 16.0	0.9	5	6.5
3D	+0.7 ± 0.5	-0.6	1182.2 ± 1.1	1180.5 ± 5.5	0.2	5	6.5
5D	-1.9 ± 1.0	-4.1	1172.1 ± 2.0	1172.6 ± 2.3	0.5	5	6.5
7D	-1.3 ± 0.6	-2.6	1136.8 ± 0.4	1137.6 ± 5.9	0.9	5	6.5
9A	-1.4 ± 0.8	-3.3	1156.4 ± 0.8	1154.9 ± 4.8	0.4	5	6.5
13C	+0.6±1.1	-1.8	1147.6 ± 4.3	1154.3 ± 3.2	<0.1	5	6.5
15A	+0.9 ± 1.7	-3.1	1124.9 ± 5.6	1127.0 ± 10.8	<0.1	5	6.5

* Since 12/8/92

2.3 Elevation 50'-2" Using Data From February 1990 through September 1996

Bay & Area	Corrosion Rate, mpy		Mean Thickness, mils		F-Ratio (5)	N(6)	Date Span yrs (7)
	Best Est.(1)	95% (2)	Best Est. (3)	Measured (4)			
5D/12	+0.3 ± 0.4	-0.5	745.0 ± 0.8	747.6 ± 1.9	<0.1	10	6.6
5/5 > Mean	-0.8 ± 0.5	-1.7	758.9 ± 1.0	757.0 ± 1.7	0.6	9	6.5
5/5 ≤ Mean	-0.7 ± 0.9	-2.4	712.7 ± 1.8	710.4 ± 6.4	<0.1	9	6.5
13/31 > Mean	-0.6 ± 1.0	-2.5	765.2 ± 2.0	768.1 ± 2.8	<0.1	9	6.5
13/31 ≤ Mean	-1.8 ± 2.0	-5.5	696.4 ± 3.9	695.8 ± 8.2	0.2	9	6.5
15/23 > Mean	-0.5 ± 0.7	-1.8	763.7 ± 1.3	760.3 ± 1.3	< 0.1	9	6.5
15/23 ≤ Mean	-0.3 ± 0.7	-1.7	736.2 ± 1.4	731.6 ± 4.8	<0.1	9	6.5

2.4 Elevation 51'-10" Using Data Thru September 1996

Bay & Area	Corrosion Rate, mpy		Mean Thickness, mils		F-Ratio (5)	N(6)	Date Span yrs (7)
	Best Est.(1)	95% (2)	Best Est. (3)	Measured (4)			
13/32 ⩾ 709	-0.3 ± 0.4	-1.1	716.4 ± 0.8	715.2 ± 1.3	0.1	8	6.4
13/32 <709	-0.02 ± 0.7	-1.3	685.0 ± 1.2	687.7 ± 4.9	<0.1	8	6.4

2.5 Elevation 60'-10" Using Data Thru September 1996

Bay & Area	Corrosion Rate, mpy		Mean Thickness, mils		F-Ratio (5)	N(6)	Date Span yrs (7)
	Best Est.(1)	95% (2)	Best Est. (3)	Measured (4)			
1/50 -22	-0.5 ± 5.7	-36.3	699.1 ± 6.1	692.5 ± 3.5	< 0.1	3	3.7

2.6 Elevation 87'-5" Using Data Thru September 1996

	Best Est.(1)	95% (2)	Best Est. (3)	Measured (4)			
9/20	-0.8 ± 0.6	-1.9	617.7 ± 1.6	612.9 ± 2.2	0.5	11	8.9
13/28	-0.7 ± 0.5	-1.6	639.1 ± 1.4	636.0 ± 1.9	0.4	11	8.9
15/31	-0.8 ±0.5	-1.7	633.4 ± 1.4	631.6 ±1.9	0.6	11	8.9

2.7 Evaluation of Individual Measurements Exceeding 99%/99% Trolerance Interval

The following data points fell outside the 99%/99% tolerance interval and thus are statistically different from the mean thickness. Evaluation of the data for each of these points indicate that only two of them may be corroding more rapidly than the overall grid.

Point 9 in Bay 5, Elev 51, Area D-1 2 has an indicated corrosion rate of -2.0 ± 0.9 mpy.

Point 25 in Bay 13, Elev 86, Area 28 has an indicated corrosion rate of -3.6 ± 1.7 mpy.

Bay	Elev	Area	Point	Mils	Dev.	Sigmas
5	51	D-1 2	9	692	-54.3	-3.7
5	51	5	17	636	-102.6	-3.3
15	51	23	26	638	-111.5	-4.6
13	52	32	23	586	-113.0	-3.4
13	52	32	28	589	-110	-3.3
1	61	50-22	48	573	-117.1	-4.0
13	86	28	25	546	-83.6	-3.9
15	86	31	34	562	-66.0	-2.9
15	86	31	35	521	-107.0	-4.8

2.8 Mean Thickness of All Points in the Grid

The following table lists the mean thickness ± 1-sigma for all the valid points (including pits) in each 6"x6" grid or 7-point strip.

Bay	Elev	Area	Date	Mean Thk
1D	Sand Bed		9/96	1073.9 ± 51.0
3D	Sand Bed		9/96	1180.5 ± 5.5
5D	Sand Bed		9/96	1172.6 ± 2.2
7D	Sand Bed		9/96	1137.6 ± 5.9
9A	Sand Bed		9/96	1154.9 ± 4.8
9D	Sand Bed		9/96	1008.0 ± 10.6
11A	Sand Bed		9/96	829.7 ± 9.1
11C	Sand Bed		9/96	951.1 ± 15.1
13A	Sand Bed		9/96	843.4 ± 7.4
13C	Sand Bed		9/96	1154.3 ± 3.2
13D	Sand Bed		9/96	989.7 ± 11.6
15A	Sand Bed		9/96	1127.0 ± 10.8
15D	Sand Bed		9/96	1066.0 ± 8.5
17A	Sand Bed		9/96	1050.4 ± 15.0
17D	Sand Bed		9/96	844.5 ± 8.9
17/19	Frame		9/96	980.4 ± 4.6
19A	Sand Bed		9/96	814.9 ± 10.0
19B	Sand Bed		9/96	837. 4 ± 9.5
19C	Sand Bed		9/96	848.0 ± 11.1
5	50'-2"	D-1 2	9/96	746.3 ± 2.3
5	50'-2"	5	9/96	738.6 ± 4.6
13	50'-2"	31	9/96	743.4 ± 6.0
15	50'-2"	23	9/96	749.5 ± 3.5
13	51'-10"	32	9/96	699.0 ± 4.7
1	60'-10"	50-22	9/96	690.1 ± 4.2
9	86'	20	9/96	612.9 ± 2.2
13	86'	28	9/96	629.6 ± 3.0
15	86'	31	9/96	628.0 ± 3.2

3.0 REFERENCES

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3.2 GPUN TDR 854, Rev. 0, "Drywell Corrosion Assessment"

3.3 GPUN TDR 851, Rev. 0, "Assessment of Oyster Creek Drywell Shell"

3.4 GPUN Installation Specification IS-328227-004, Rev. 11, "Functional Requirements for Drywell Containment Vessel Thickness Examination"

3.5 Applied Regression Analysis, 2nd Edition, N.R. Draper & H. Smith, John Wiley & Sons, 1981

3.6 Statistical Concepts and Methods, G.K. Bhattacharyya & R.A. Johnson, John Wiley & sons, 1977

3.7 GPUN Calculation C-1302-187-5300-005, Rev. 0, "Statistical Analysis of Drywell Thickness Data Thru 12-31-88"

3.8 GPUN TDR 948, Rev. 1, "Statistical Analysis of Drywell Thickness Data"

3.9 Experimental Statistics, Mary Gibbons Natrella, John Wiley & Sons, 1966 Reprint. (National Bureau of Standards Handbook 91)

3.10 Fundamental Concepts in the Design of Experiments, Charles C. Hicks, Saunders College Publishing, Fort Worth, 1982

3.11 GPUN Calculation C-1302-187-5300-008, Rev. 0, "Statistical Analysis of Drywell Thickness Data thru 2-8-90"

3.12 GPUN Calculation C-1302-187-5300-011, Rev. 1, "Statistical Analysis of Drywell Thickness Data Thru 4-24-90"

3.13 GPUN Calculation C-1302-187-5300-015, Rev. 0, "Statistical Analysis of Drywell Thickness Data Thru March 1991"

3.14 GPUN Calculation C-1302-187-5300-017, Rev. 0, "Statistical Analysis of Drywell Thickness Data Thru May 1991"

3.15 GPUN Calculation C-1302-187-5300-019, Rev. 0, "Statistical Analysis of Drywell Thickness Data Thru November 1991"

3.16 GPUN Calculation C-1302-187-5300-020, Rev. 0, "OCDW Projected Thickness Using Data Thru 11/02/91"

3.17 GPUN Calculation C-1302-187-5300-021, Rev. 0, "Statistical Analysis of Drywell Thickness Data Thru May 1992"

3.18 GPUN Calculation C-1302-187-5300-022, Rev. 0, "OCDW Projected Thickness Using Data Thru 5/31/92"

3.19 GPUN Calculation C-1302-187-5300-025, Rev. 0, "Statistical Analysis of Drywell Thickness Data Thru December 1992"

3.20 GPUN Calculation C-1302-187-5300-024, Rev. 0, "OCDW Projected Thickness Using Data Thru 12/8/92"

3.21 GPUN Calculation C-1302-187-5300-028, Rev. 0, "OCDW Statistical Analysis of Drywell Thickness Data Thru September 1994"

3.22 GPUN Mainframe datafiles# Na277.DWDEC92.data; Na277.DWFEB91.data; Na277.DWMAR90.data; Na277.DWMAR91.data; Na277.DWMAY91.data; a277.DWMAY92.data; Na277.DWNOV91.data; Na277.DWSEP94.data; Na277.DWSEP96.data;

3.23 GPUN Mainframe SAS MACROs File# NA277.SAS6.MACLIB.

3.24 GPUN Mainframe SAS Library files # Na277.DWDEC92.lib; Na277.DWSEP94.lib; Na277.DWSEP96.lib;

3.25 GPUN Mainframe SAS Preograms Files # Na277.SAS. OCDW.PROGS.

4.0 ASSUMPTIONS & BASIC DATA

4.1 Background

The design of the carbon steel drywell includes a sand bed which is located around the outside circumference between elevations 8'-11-1/4" and 12'-3". Leakage was observed from the sand bed drains during the 1980, 1983 and 1986 refueling outages indicating that water had intruded into the annular region between the drywell shell and the concrete shield wall.

The drywell shell was inspected in 1986 during the 10R outage to determine if corrosion was occurring. The inspection methods, results and conclusions are documented in Ref. 3.1, 3.2, and 3.3. As a result of these inspections it was concluded that a long term monitoring program would be established. This program initially included repetitive Ultrasonic Thickness (UT) measurements in the sand bed region at a nominal elevation of 11'-3" in bays 11A, 11C, 17D, 19A, 19B, and 19C.

The continued presence of water in the sand bed raised concerns of potential corrosion at higher elevations. Therefore, UT measurements were taken at the 50'-2" and 87'-5" elevations in November 1987 during the 11R outage. As a result of these inspections, repetitive measurements in Bay 5 at elevation 50'-2" and in Bays 9, 13 and 15 at the 87'-5" elevation were added to the long term monitoring program to confirm that corrosion is not occurring at these higher elevations.

During the 12R outage, a cathodic protection system was installed in the sand bed region of Bays 11A, 11C, 17D, 19A, 19B, 19C, and at the frame between Bays 17 and 19 to minimize corrosion of the drywell. The cathodic protection system was placed in service on January 31, 1989, but proved to be ineffective and was removed from service. The long term monitoring program was also expanded during the 12R outage to include measurements in the sand bed region of Bays 1D, 3D, 5D, 7D, 9A, 13A, 13C, 13D, 15A, 15D, 17A and the sand bed region between Bays 17 and 19.

The high corrosion rate computed for Bay 13A in the sand bed region through February 1990 (Ref. 3.11) raised concerns about the corrosion rate in the sand bed region of Bay 13D. Therefore, the monitoring of this location using a 6"x6" grid was added to the long term monitoring program. In addition, a 2-inch core sample was removed in March 1990 from a location adjacent to the 6"x6" monitored grid in Bay 13A.

Measurements taken in Bay 5 Area D-12 at elevation 50'-2" through March 1990 indicated that corrosion was occurring at this location. Therefore, survey measurements were taken to determine the thinnest locations at elevation 50'-2". As a result, three new locations were added to the long term monitoring program (Bay 5 Area 5, Bay 13 Area 31, and Bay 15 Area 23).

The indication of ongoing corrosion at elevation 50'-2" raised concerns about potential corrosion of the plates immediately above which have a smaller nominal thickness. Therefore, survey measurements were taken in April 1990 at the 51'-10" elevation in all bays to determine the thinnest locations. As a result of this survey, one new location was added to the long term monitoring plan at elevation 51'-10" (Bay 13 Area 32).

A program to stop the corrosion in the sand bed region commenced on November 29, 1991 with the removal of sand from Bay 11. As of April 1, 1992, a total of 77 barrels of sand had been removed and sand removal was stopped on that date.

The remaining sand was removed during the 14R Refueling Outage which commenced on November 28, 1992. During the 14R Outage, the oxide scale in the sandbed region was removed, and the surface was cleaned and coated to prevent additional corrosion.

Some measurements in the long term monitoring program are taken at each outage of opportunity, while others are taken during each refueling outage. The functional requirements for these inspections are documented in Ref. 3.4. The purpose of the UT measurements is to determine the corrosion rate and monitor it over time.

4.2 Selection of Areas to be Monitored

A program was initiated during the 11R outage to characterize the corrosion and to determine its extent. The details of this inspection program are documented in Ref. 3.3. The greatest corrosion was found via UT measurements in the sand bed region at the lowest accessible locations. Where thinning was detected, additional measurements were made in a cross pattern at the thinnest section to determine the extent in the vertical and horizontal directions. Having found the thinnest locations, measurements were made over a 6"x6" grid.

To determine the vertical profile of the thinning, a trench was excavated into the floor in Bay 17 and Bay 5. Bay 17 was selected since the extent of thinning at the floor level was greatest in that area. It was determined that the thinning below the top of the curb was no more severe than above the curb, and became less severe at the lower portions of the sand cushion. Bay 5 was excavated to determine if the thinning line was lower than the floor level in areas where no thinning was detected above the floor. There were no significant indications of thinning in Bay 5.

It was on the basis of these findings that the 6"x6" grids in Bays 11A, 11C, 17D, 19A, 19B and 19C were selected as representative locations for longer term monitoring. The initial measurements at these locations were taken in December 1986 without a template or markings to identify the location of each measurement. Subsequently, the location of the 6"x6" grids were permanently marked on the drywell shell and a template is used in conjunction with these markings to locate the UT probe for successive measurements. Analyses have shown that including the non-template data in the data base creates a significant variability in the thickness data. Therefore, to minimize the effects of probe location, only those data sets taken with the template are included in the analyses.

The presence of water in the sand bed also raised concern of potential corrosion at higher elevations. Therefore, UT measurements were taken at the 50'-2" and 87'-5" elevations in 1987 during the 11M outage. The measurements were taken in a band on 6-inch centers at all accessible regions at these elevations. Where these measurements indicated potential corrosion, the measurements spacing was reduced to 1-inch on centers. If these additional readings indicated potential corrosion, measurements were taken on a 6"x6" grid using the template. It was on the basis of these inspections that the 6"x6" grids in Bay 5 at elevation 50'-2" and in bays 9, 13 and 15 at the 87'-5" elevation were selected as representative locations for long term monitoring.

The long term monitoring program was expanded as follows during the 12R outage:

(1) Measurements on 6"x6" grids in the sand bed region of Bays 9D, 13A, 15D and 17A: The basis for selecting these locations is that they were originally considered for cathodic protection but were not included in the system when it was installed.

(2) Measurements on 1-inch centers along a 6-inch horizontal strip in the sand bed region of Bays 1D, 3D, 5D, 7D, 9A, 13C, and 15A: These locations were selected on the basis that they are representative of regions which have experienced nominal corrosion and were not within the scope of the cathodic protection system.

(3) A 6"x6" grid in the curb cutout between Bays 17 and 19: The purpose of these measurements was to monitor corrosion in this region which was covered by the cathodic protection system but did not have a reference electrode to monitor its performance.

The long term monitoring program was expanded in March 1990 as follows:

(1) Measurements in the sand bed region of Bay 13D: This location was added due to the high indicated corrosion rate in the sand bed region of Bay 13A. The measurements taken in March 1990 were taken on a 1"x6" grid. All subsequent measurements are to be taken on a 6"x6" grid.

(2) Measurements on 6"x6" grids at elevation 50'-2" in Bay 5 Area 5, Bay 13 Area 31, and Bay 15 Area 23: These locations were added due to the indication of ongoing corrosion at elevation 50'-2", Bay 5 Area D-1.

The long term monitoring program was expanded in April 1990 by adding Bay 13 Area 32 at elevation 51'-10". This location was added due to the indication of ongoing corrosion at elevation 50'-2" and the fact that the nominal plate thickness at elevation 51'-10" is less than at elevation 50'-2".

In April 1991, a series of inspections were performed at randomly selected locations between elevations 12' and 95'. None of these locations had been previously inspected. The average thickness of the 6"x6" grid on plate 50-22 was 678 mils. This was slightly less than the average thickness of the monitored location at elevation 51' 10". Therefore, this location was added to the long term monitoring program.

4.3 UT Measurements

The UT measurements within the scope of the long term monitoring program are performed in accordance with Ref. 3.4. This involves taking UT measurements using a template with 49 holes laid out on a 6"x6" grid with 1" between centers on both axes. The center row is used in those bays where only 7 measurements are made along a 6-inch horizontal strip.

The first set of measurements were made in December 1986 without the use of a template. Ref. 3.4 specifies that for all subsequent readings, QA shall verify that locations of UT measurements performed are within ± 1/4" of the location of the 1986 UT measurements. It also specifies that all subsequent measurements are to be within ± 1/8" of the designated locations.

4.4 Data at Plug Locations

Seven core samples, each approximately two inches in diameter were removed from the drywell vessel shell. These samples were evaluated in Ref. 3.2. Five of these samples were removed within the 6"x6" grids for Bays 11A, 17D, 19A, 19C and Bay 5 at elevation 50'-2". These locations were repaired by welding a plug in each hole. Since these plugs are not representative of the drywell shell, UT measurements at these locations on the 6"x6" grid must be dropped from each data set.

The following specific grid points have been deleted:

Bay Area	Points
11A	23, 24, 30, 31
17D	15, 16, 22, 23
19A	24, 25, 31, 32
19C	20, 26, 27, 33,
EL 50'-2" 5 Area D 12	13, 20, 25, 26, 27, 28, 33, 34, 35

The core sample removed in the sand bed region of Bay 13A was not within the monitored 6"x6" grid.

4.5 Bases for Statistical Analysis of 6"x6" Grid Data

4.5.1 Assumptions

The statistical evaluation of the UT measurement data to determine the corrosion rate at each location is based on the following assumptions:

(1) Characterization of the scattering of data over each 6"x6" grid is such that the thickness measurements are normally distributed. If the data are not normally distributed, the grid is subdivided into normally distributed subdivisions.

(2) Once the distribution of data is found to be normal, the mean value of the thickness is the appropriate representation of the average condition.

(3) A decrease in the mean value of the thickness with time is representative of the corrosion occurring within the 6"x6" grid.

(4) If corrosion has ceased, the mean value of the thickness will not vary with time except for random variations in the UT measurements.

(5) If corrosion is continuing at a constant rate, the mean thickness will decrease linearly with time. In this case, linear regression analysis can be used to fit the mean thickness values for a given zone to a straight line as a function of time. The corrosion rate is equal to the slope of the line.

The validity of these assumptions is assured by:

(a) Using more than 30 data points per 6"x6" grid

(b) Testing the data for normality at each 6"x6" grid location.

(c) Testing the regression equation as an appropriate model to describe the corrosion rate.

These tests are discussed in the following section. In cases where one or more of these assumptions proves to be invalid, non-parametric analytical techniques can be used to evaluate the data.

4.5.2 Statistical Approach

The following steps are performed to test and evaluate the UT measurement data for those locations where 6"x6" grid data has been taken at least three times:

(1) Edit each 49-point data set by setting all invalid points to "missing." Invalid points are those which are declared invalid by the UT operator or are at a plug location. (The computer programs used in the following steps ignore all "missing" thickness data points.)

(2) Perform a Univariate Analysis of each 49 point data set to ensure that the assumption of normality is valid.

(3) Calculate the mean thickness and variance of each 49 point data set.

(4) Perform an Analysis of Variance (ANOVA) F-test to determine if there is a significant difference between the means of the data sets.

(5) Using the mean thickness values for each 6"x6" grid, perform linear regression analysis over time at each location.

(a) Perform F-test for significance of regression at the 5% level of significance. The result of this test indicates whether or not the regression model is more appropriate than the mean model. In other words, it tests to see if the variation due to corrosion is statistically significant compared to the random variations.

(b) Calculate the ratio of the observed F value to the critical F value at 5% level of significance. For data sets where the Residual Degress of Freedom in ANOVA is 4 to 9, this F-Ratio should be at least 8 for the regression to be considered "reliable" as opposed to simply "significant." (See paragraph 4.10.2)

(c) Calculate the coefficient of determination (R^2) to assess how well the regression model explains the percentage of total error and thus how useful the regression line will be as a predictor.

(d) Determine if the residual values for the regression equations are normally distributed.

(e) Calculate the y-intercept, the slope and their respective standard errors. The y-intercept represents the fitted mean thickness at time zero, the slope represents the corrosion rate, and the standard errors represent the uncertainty or random error of these two parameters. Calculate the upper bound of the 95% one-sided confidence interval about the computed slope to provide an estimate of the maximum probable corrosion rate at 95% confidence. This is explained in greater detail in paragraph 4.10.2.

(f) When the corrosion rate is not statistically significant compared to random variations in the mean thickness, the slope and confidence interval slope computed in the regression analysis still provides an estimate of the corrosion rate which could be masked by the random variations. This is explained in greater detail in paragraph 4.10.1.

(6) Use the chi-square goodness of fit test results to determine if low thickness measurements are significant pits. If the measurement deviates from the mean thickness by three standard deviations, it is considered to be a significant pit.

4.6 Analysis of Two 6"x6" Grid Data Sets

Regression analysis is inappropriate when data is available at only two points in time. However, the Analysis of Variance F-test can be used to determine if the means of the two data sets are statistically different.

4.6.1 Assumptions

This analysis is based upon the following assumptions:

(1) The data in each data set is normally distributed.

(2) The variances of the two data sets are equal.

4.6.2 Statistical Approach

The evaluation takes place in three steps:

(1) Perform a Univariate Analysis of each data set to ensure that the assumption of normality is valid.

(2) Perform an F-test at 5% level of significance of the two data sets being compared to ensure that the assumption of equal variances is valid.

(3) Perform an Analysis of Variance F-test at the 5% level of significance to determine if the means of the two data sets are statistically different.

A conclusion that the means are not statistically different is interpreted to mean that significant corrosion did not occur over the time period represented by the data. However, if equality of the means is rejected, this implies that the difference is statistically significant and could be due to corrosion.

The range of potential corrosion rates is estimated by computing the slope of the steepest line which can be drawn within the ± 1 sigma confidence interval about the mean thickness for the duration between the two measurements.

4.7 Analysis of Single 6"x6" Grid Data Set

In those cases where a 6"x6" data set is taken at a given location for the first time during the current outage, the only other data to which they can be compared are the UT survey measurements taken at an earlier time. For the most part, these are single point measurements which were taken in the vicinity of the 49-point data set, but not at the exact location. Therefore, rigorous statistical analysis of these single data sets is impossible. However, by making certain assumptions, they can be compared with the previous data points. If more extensive data is available at the location of the 49-point data set, the Analysis of Variance F-test can be used to compare the means of the two data sets as described in paragraph 4.5.

When additional measurements are made at these exact locations during future outages, more rigorous statistical analyses can be employed.

4.7.1 Assumptions

The comparison of a single 49-point data sets with previous data from the same vicinity is based on the following assumptions:

(1) Characterization of the scattering of data over the 6"x6" grid is such that the thickness measurements are normally distributed.

(2) Once the distribution of data for the 6"x6" grid is found to be normal, then the mean value of the thickness is the appropriate representation of the average condition.

(3) The prior data is representative of the condition at this location at the earlier date.

4.7.2 Statistical Approach

The evaluation takes place in four steps:

(1) Perform a univariate analysis of each data set to ensure that the assumption of normality is valid.

(2) Calculate the mean and the standard error of the mean of the 49-point data set.

(3) Determine the two-tailed t value from a t distribution table at levels of significance of 0.05 for n-1 degrees of freedom.

(4) Use the t value and the standard error of the mean to calculate the 95% confidence interval about the mean of the 49-point data set.

(5) Compare the prior data point(s) with these confidence intervals about the mean of the 49-point data sets.

If the prior data falls within the 95% confidence intervals, it provides some assurance that significant corrosion has not occurred in this region in the period of time covered by the data.

If the prior data falls above the upper 95% confidence limit, it could mean either of two things: (1) significant corrosion has occurred over the time period covered by the data, or (2) the prior data point was not representative of the condition of the location of the 49-point data set in 1986. There is no way to differentiate between the two.

If the prior data falls below the lower 95% confidence limit, it means that it is not representative of the condition at this location at the earlier date.

4.8 Analysis of 7-Point Data Sets

4.8.1 Analysis of Multiple 7-Point Data Sets

When three or more data sets are available, the data are tested and evaluated using the methodology described in 4.5.2 for 6"x6" Grid Data. The only exception is that a chi-square goodness of fit test is not performed because it would be statistically meaningless for 7-point data sets.

4.8.2 Analysis of Single 7-Point Data Set

In those cases where a 7-point data set is taken at a given location for the first time during the current outage, the only other data to which they can be compared are the UT survey measurements taken at an earlier time to identify the thinnest regions of the drywell shell in the sand bed region. For the most part, these are single point measurements which were taken in the vicinity of the 7-point data sets, but not at the exact locations. However, by making certain assumptions, they can be compared with the previous data points.

4.8.2.1 Assumptions

The comparison of a single 7-point data sets with previous data from the same vicinity is based on the following assumptions:

(1) The corrosion in the region of each 7-point data set is normally distributed.

(2) The prior data is representative of the condition at this location at the earlier date.

The validity of these assumptions cannot be verified.

4.8.2.2 Statistical Approach

Perform the Analysis of Variance and F-test

If the prior data falls within the 95% confidence interval, it provides some assurance that significant corrosion has not occurred in this region in the period of time covered by the data.

If the prior data falls above the upper 95% confidence interval, it could mean either of two things: (1) significant corrosion has occurred over the time period covered by the data, or (2) the prior data point was not representative of the condition of the location of the 7-point data set in 1986. There is no way to differentiate between the two.

If the prior data falls below the lower 99% confidence limit, it means that it is not representative of the condition at this location at the earlier date. In this case, the corrosion rate will be interpreted to be "Indeterminable".

4.9 Evaluation of Drywell Mean Thickness

This section defines the methods used to evaluate the drywell thickness at each location within the scope of the long term monitoring program.

4.9.1 Evaluation of Mean Thickness Using Regression Analysis

The following procedure is used to evaluate the drywell mean thickness at those locations where regression analysis has been deemed to be significant (F-Ratio is 1.0 or greater).

(1) The best estimate of the mean thickness at these locations is the point on the regression line corresponding to the time when the most recent set of measurements was taken. In the SAS Regression Analysis output (App. 6.2), this is the last value in the column labeled "PREDICT VALUE".

(2) The best estimate of the standard error of the mean thickness is the standard error of the predicted value used above. In the SAS Regression Analysis output, this is the last value in the column labeled "STD ERR PREDICT".

(3) The two-sided 95% confidence interval about the mean thickness is equal to the mean thickness plus or minus t times the estimated standard error of the mean. This is the interval for which we have 95% confidence that the true mean thickness will fall within. The value of t is obtained from a t distribution table for equal tails at n-2 degrees of freedom and 0.05 level of significance, where n is the number of sets of measurements used in the regression analysis. The degrees of freedom is equal to n-2 because two parameters (the y-intercept and the slope) are calculated in the regression analysis with n mean thicknesses as input.

(4) The one-sided 95% lower limit of the mean thickness is equal to the estimated mean thickness minus t times the estimated standard error of the mean. This is the mean thickness for which we have 95% confidence that the true mean thickness does not fall below. In this case, the value of t is obtained from a t distribution table for one tail at n-2 degrees of freedom and 0.05 level of significance.

4.9.2 Evaluation of Mean Thickness Using Mean Model

The following procedure is used to evaluate the drywell mean thickness at those locations where the regression analysis is not significant (F-Ratio is less than 1.0). This method is consistent with that used to evaluate the mean thickness using the regression model.

(1) Calculate the mean of each set of UT thickness measurements.

(2) Sum the means of the sets and divide by the number of sets to calculate the grand mean. This is the best estimate of the mean thickness. In the SAS Regression Analysis output, this is the value labelled "DEP MEAN".

(3) Using the means of the sets from (1) as input, calculate the standard error about the mean. This is the best estimate of the standard error of the mean thickness.

(4) The two-sided 95% confidence interval about the mean thickness is equal to the mean thickness plus or minus t times the estimated standard error of the mean. This is the interval for which we have 95% confidence that the true mean thickness will fall within. The value of t is obtained from a t distribution table for equal tails at n-1 degrees of freedom and 0.05 level of significance.

(5) The one-sided 95% lower limit of the mean thickness is equal to the estimated mean thickness minus t times the estimated standard error of the mean. This is the mean thickness for which we have 95% confidence that the true mean thickness does not fall below. In this case, the value of t is obtained from a t distribution table for one tail at n-1 degrees of freedom and 0.05 level of significance.

4.9.3 Evaluation of Mean Thickness Using Single Data Set

The following procedure is used to evaluate the drywell thickness at those locations where only one set of measurements is available.

(1) Calculate the mean of the set of UT thickness measurements. This is the best estimate of the mean thickness.

(2) Calculate the standard error of the mean for the set of UT measurements. This is the best estimate of the standard error of the mean thickness.

Confidence intervals about the mean thickness cannot be calculated with only one data set available.

4.10 Evaluation of Drywell Corrosion Rate

4.10.1 Regression Not Significant

If the ratio of the observed F value to the critical F value is less than 1 for the F-test for the significance of regression, it indicates that the regression is not significant at the 5% level of significance. In other words, the variation in mean thickness with time can be explained solely by the random variations in the measurements. This means that the corrosion rate is not statistically significant compared to the random variations. The critical F value is determined for n-2 degrees of freedom: F(1, n-2, 0.95).

The possibility does exist that the variability in the data may be masking an actual corrosion rate. Although the regression is not the result of the regression analysis can be used to estimate the potentially masked corrosion rate. We can also state with 95% confidence that the corrosion rate does exceed the upper bound of the 95% one-sided confidence interval of the slope computed in the regression analysis. The 95% upper bound is equal to the computed slope plus the one-sided t-table value times the standard error of the slope. The value of t is determined for n-2 degrees of freedom.

4.10.2 Regression Significant

If the ratio of the observed F value to the critical F value is 1 or greater, it indicates that the regression model is more appropriate than the mean model at the 5% level of significance. In other words, the variation in mean thickness with time cannot be explained solely by the random variations in the measurements. This means that the corrosion rate is significant compared to the random variations.

Although a ratio of 1 or greater indicates that regression is significant, it does not mean that the slope of the regression line is an accurate prediction of the corrosion rate. The ratio should be at least 4 or 5 to consider the slope to be a useful predictor of the corrosion rate (Ref. 3.5, pp. 93, 129-133). A ratio of 4 or 5 means that the variation from the mean due to regression is approximately twice the standard deviation of the residuals of the regression. To have a high degree of confidence in the predicted corrosion rate, the ratio should be at least 8 or 9 (Ref. 3.5, pp. 129-133).

The upper bound of the 95% one-sided confidence interval about the computed slope is an estimate of the maximum probable corrosion rate at 95% confidence. The 95% upper bound is equal to the computed slope plus the one-sided t-table value times the standard error of the slope. The value of t is determined for n-2 degrees of freedom.

5.0 RESULTS OF CALCULATIONS

5.1 Sand Bed Region

5.1.1 6"x6" Grids in Sand Bed Region

5.1.1.1 Bay 9D 2/8/90 to 9/16/96

There is a pit at point 15 which deviates from the mean thickness by about 2.9-sigma. Therefore, point 15 is omitted from this analysis and is evaluated separately as a pit.

Nine 49-point data sets were available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

Pit at Point 15

The pit at point 15 does not fall outside the 99% confidence interval, and thus is not statistically significant. The prior data indicates a significant corrosion rate prior to February 1991. The mean of the six readings since then is 774.4 $\pm$ 4.8 mils. The current reading is 776 mils. Thus, there is no indication of ongoing corrosion.

5.1.1.2 Bay 11A: 2/8/90 to 9/16/96

The regression of nine data sets for this period meets the acceptance criteria and is statistically significant.

5.1.1.3 Bay 11C: 2/8/90 to 9/16/96

Prior analysis have shown that there has been minimal corrosion in the top 3 rows of the 6" x 6" grid with more extensive corrosion in the bottom 4 rows. Therefore, these subsets are analyzed separately.

Nine 49-point data sets were available for this period.

Top 3 Rows

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) Except for the September 1996 data set, the Analysis of Variance shows that there is no significant difference in the means at 95% confidence. The 9/19/96 measurements are somewhat higher.

There is no indication of statistically significant corrosion during this time period.

Bottom 4 Rows

The 12/8/92 measurement at point 43 is 603 mils, which deviates from the mean thickness by 4.3-sigma. None of the other readings at this point deviated significantly from the mean. The mean thickness of other readings at this point is 884.0 $\pm$ 7.4 mils. Therefore, this measurement is classified as an outlier.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) Except for the February 1990, May 1992 and September 1996 data sets, the Analysis of Variance shows that there is no significant difference in the means at 95% confidence. The means are greater for February 1990, May 1992, and September 1996.

There is no indication of statistically significant corrosion during this time period.

5.1.1.4 **Bay 13A: 2/8/90 to 9/16/96**

Ten 49-point data sets were available for this period. Four points (4, 5, 6, & 7) have experienced much less corrosion than the rest of the grid and the readings are consistently much higher than the other points. These four points were dropped from the analysis to achieve normally distributed data sets.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) Except for February 1990 and May 1992, the Analysis of Variance shows that there is no significant difference in the means at 95% confidence. The means at other locations are also greater for February 1990 and May 1992.

Thus, there is no indication of statistically significant corrosion during this time period.

5.1.1.5 **Bay 13D: 4/25/90 to 9/16/96**

Eight 49-point data sets were available for this period.

Prior evaluation showed that there was a line of demarcation separating a zone of minimal corrosion at the top from a corroded zone at the bottom. Thus, it was concluded that corrosion has occurred at this location.

The 49-point data set of 2/23/91 contains an invalid measurement at point #47. Therefore, this was input as a "missing" value to exclude it from the analyses. The data sets have a line of demarcation separating the upper and lower zones. Therefore, the grid was divided into two zones consisting of the following points:

Top Zone	Bottom Zone
1 - 16	17 - 18
19 - 22	23 - 26
27 - 28	29 - 49

Top Zone

This zone consists of 22 points.

(1) The data are normally distributed.

(2) The regression is not statistically significant.

(3) Analysis of variance shows no significant difference between the means except for the May 1992 mean which is significantly greater than the prior means. The means at other locations also are greater for May 1992.

There is no indication of statistically significant corrosion during this period.

Bottom Zone

This zone consists of 27 points.

(1) The data are normally distributed except for the 4/25/90 data which is skewed. The 9/16/96 measurement of 1032 mils at point 25 is much higher than prior readings, but the 9/16/96 data is still normally distributed.

(2) The regression is not statistically significant.

(3) Analysis of variance shows no significant difference between the means except for the May 1992 and September 1996 means which are significantly greater than the other means. The means at other locations are also greater for May 1992. The September 1996 mean is high due to point 25 (see above).

There is no indication of statistically significant corrosion during this period.

5.1.1.6 **Bay 15D: 2/8/90 to 9/16/96**

Nine 49-point data sets were available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.1.7 **Bay 17A: 2/8/90 to 9/16/96**

Nine 49-point data sets were available for this period.

Prior analyses have shown a lack of normality due to minimal corrosion in the top 3 rows and more extensive corrosion in the bottom 4 rows. Therefore, these subsets are analyzed separately.

Top 3 Rows

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

Bottom 4 Rows

(1) The regression has a positive slope and is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.1.8 **Bay 17D: 2/8/90 to 9/16/96**

Nine 49 point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.1.9 **Bay 17/19 Frame Cutout: 2/8/90 to 9/16/96**

Nine 49-point data sets were available for this period.

Prior analyses have shown a lack of normality due to more extensive loss of thickness in the top 3 rows than in the bottom 4 rows. Therefore, these subsets are analyzed separately.

Top 3 Rows

(1) The regression is not statistically significant.

(2) The data are normally distributed except for February 1990 due to high readings at points 20 & 21, and May 1992 due to a high reading at point 20.

(3) Except for February 1990 and November 1991, the Analysis of Variance shows that there is no significant difference in the means at 95% confidence. The February 1990 mean is high due to points 20 & 21. In November 1991, the readings at all points tended to be lower than at other times.

There is no indication of statistically significant corrosion during this time period.

Bottom 4 rows

(1) The regression is not statistically significant.

(2) The data are normally distributed except for readings in February 1990, April 1990, and September 1994 which have one or two high or low readings.

(3) Except for February 1990 with two high readings, the Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.1.10 **Bay 19A: 2/8/90 to 9/16/96**

Nine 49-point data sets were available for this period. Since a plug lies within this region, four of the points were voided in each data set.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.1.11 **Bay 19B: 2/8/90 to 9/16/96**

Nine 49-point data sets were available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) Except for September 1994 and February 1991, the Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.1.12 **Bay 19C: 2/8/90 to 9/16/96**

Nine 49-point data sets were available for this period. Since a plug lies within this region, four of the points were voided in each data set.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant corrosion during this time period.

5.1.2 **1x7 Strips in Sand Bed Region**

5.1.2.1 **Bay 1D: 3/28/90 to 9/16/96**

Five 7-point data sets are availbale for this period.

The measurements at point 1 are consistently well below the other 6 points. The September 1996 measurement of 881 mils is 197 mils below the mean of the 7 points. This represents a difference of 2.1 standard deviations. It does not fall outside the 99% confidence interval, and thus is not a statistically significant pit. However, the data sets are not normally distributed when it is included. Therefore, point 1 is omitted from the analyses.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance indicates that there is a significant difference between the means of the May 1991 and September 1996. This is due to the May 1991 measurement of 1195 at point 5 which is 50 mils above the mean of the 4 readings at this point.

There is no indication of statistically significant ongoing corrosion during this period.

5.1.2.2 **Bay 3D: 3/28/90 to 9/16/96**

Five 7-point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance shows that there is no significant difference in the means at 95% confidence.

There is no indication of statistically significant ongoing corrosion during this period.

5.1.2.3 **Bay 5D: 3/28/90 to 9/16/96**

Five 7-point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance indicates a significant difference between the May 1991, the September 1994 and the September 1996 means. This is due to the May 1991 measurement of 1245 at point 2 which is 45 mils above the mean of the 4 readings at this point.

There is no indication of statistically significant ongoing corrosion during this period.

5.1.2.4 **Bay 7D: 3/28/90 to 9/16/96**

Five 7-point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance indicates there is no significant difference in the means at 95% confidence.

(4) When the 28 measurements from the four data sets are pooled, the Univariate Analysis indicates they are normally distributed.

There is no indication of statistically significant ongoing corrosion during this period.

5.1.2.5 **Bay 9A: 3/28/90 to 9/16/96**

Five 7-point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The Univariate Analysis indicates the data are not normally distributed. This is due to point 7 whose mean of 1134 is 24 mils below the grand mean of 1158.

(3) The Analysis of Variance indicates there is no significant difference between the means.

There is no indication of statistically significant ongoing corrosion during this period.

5.1.2.6 **Bay 13C: 3/28/90 to 9/16/96**

Five 7-point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The data are normally distributed.

(3) The Analysis of Variance indicates there is no significant difference between the means.

There is no indication of statistically significant ongoing corrosion during this period.

5.1.2.7 **Bay 15A: 3/28/90 to 9/16/96**

Five 7-point data sets are available for this period.

(1) The regression is not statistically significant.

(2) The Univariate Analysis indicates the data are not normally distributed. This is due to point 7 whose mean of 1060 is 62 mils below the grand mean of 1122.

(3) The Analysis of Variance indicates there is no significant difference between the means.

There is no indication of statistically significant ongoing corrosion during this period.

5.2 6" x 6" Grids at Elevation 50'-2"

5.2.1 Bay 5 Area D-1 2: 2/8/90 to 9/16/96

Ten 49 point data sets were available for this period. Since a plug lies within this region, nine of the points were voided in each data set.

The initial analysis of these data sets indicated that they are not normally distributed. The following adjustments were made to the data:

(1) Point 9 is a significant pit. Therefore, it was dropped from the overall analysis and is evaluated separately.

(2) Points 1, 4 and 37 in the 4/25/90 data set are much greater than the preceding or succeeding measurements. Therefore, these three data points were dropped from the analysis.

(3) Points 3 and 36 in the 11/02/91 data set are much greater than the preceding or succeeding measurements. Therefore, these two data points were dropped from the analysis.

With these adjustments, the Univariate Analyses indicate that all of the data sets are normally distributed at the 1% level of significance.

The data indicate ongoing corrosion prior to 1990, but little or none since then. Therefore, the regression analysis was run using data since February 1990.

(1) The regression is not statistically significant.

(2) The measurements are normally distributed.

(3) Analysis of variance shows that there is a statistically significant difference between some of the means. The 2/23/91 and 9/14/94 means are less than all prior and susbsequent means. However, they are only 4 mils less than the grand mean of all the measurements.

Thus, there is no indication of statistically significant corrosion during this time period.

Pit at Point 9

The mean thickness of all measurements since 2/8/90 is 689.9 $\pm$1.4 mils, and the standard deviation of the measurements is $\pm$4.5 mils. The best estimate of the corrosion rate is -0.6 $\pm$0.7 mils per year with an R^2=9%. The current depth of the pit is about 56 mils. It is concluded that the indicated corrosion rate in the pit is slightly more than the overall grid.

5.2.2 **Bay 5 Area 5: 3/31/90 to 9/16/94**

Nine 49-point data sets were available for this period.

The data are not normally distributed due to a large corroded patch near the center of the grid and several smaller patches on the periphery.

The data was split into two subsets consisting of points whose mean value is less than or equal to the grand mean, and those greater than the grand mean. Most of the corrosion is located in the center of the grid.

Points With Mean Less than Grand Mean w/o Pit @ 17

(1) The regression is not statistically significant.

(2) These 16-point subsets are normally distributed.

(3) Analysis of variance shows that there is not a significant difference between the means of the subsets.

There is no indication of statistically significant corrosion during this period.

Points with Mean Greater than Grand Mean

The high reading of 815 mils for point 1 in December 1992 is classified as an outlier.

(1) The regression is not statistically significant.

(2) These 32-point subsets are normally distributed with the 11/2/91 and 5/31/92 data being normally distributed at 99% confidence.

(3) Analysis of variance shows that there is a statistically significant difference between some of the means. The 9/14/94 mean is less than all prior and subsequent means.

There is no indication of statistically significant corrosion during this period.

Pit at Point 17

The mean of the nine measurements at point 17 is 654.4 ±10.4 mils. It is located adjacent to points which are more than 100 mils thicker, and the readings vary due to shifting of the template. There is no indication that this point is corroding more rapidly than the overall grid.

5.2.3 Bay 13 Area 31: 3/31/90 to 9/16/96

Nine 49-point data sets were available for this period.

The data are not normally distributed. This is due to a large corroded patch at the left edge of the grid.

The data was split into two subsets consisting of those points whose mean value is less than or equal to the grand mean, and those greater than the grand mean.

Points with Mean Less than Grand Mean

(1) The regression is not statistically significant.

(2) These 16-point subsets are normally distributed.

(3) Analysis of Variance shows that there is a significant difference between the mean of the April 1990 subset and the means of some of the other subsets. This is due to the April 1990 mean of 721.6 mils, which is significantly higher than the grand mean of all the subsets.

(4) There is no indication of statistically significant corrosion during this period.

Points with Mean Greater than Grand Mean

These 33-point subsets are not normally distributed. This is due to two points (7 & 10) with high readings in April 1990, two points (30 & 43) with low readings in February 1991, and two points (12 & 36) with low readings in September 1994. When these points are deleted, the subsets are normally distributed.

These subsets with the outliers deleted are evaluated below.

(1) The regression is not statistically significant.

(2) Analysis of variance shows that there is a statistically significant difference in the means. The September 1996 mean is less than prior means except it is greater than February and May 91 and September 1994 means. The small difference in means further supports the conclusion of item #1 (i.e., the regression is not statistically significant).

(3) There is no indication of statistically significant corrosion during this period.

5.2.4 Bay 15 Area 23: 3/31/90 to 9/16/96

Nine 49-point data sets were available for this period.

The data are not normally distributed. This is due to a large corroded patch near the center of the grid and a significant pit at point 26. There are also some random readings over 780 mils which are outliers. Also, the measurement of 638 mils at point 27 in November 1991 is 118 mils less than the lowest prior measurement. This point is adjacent to the pit at point 26 and was therefore deleted.

The data was split into two subsets:

(1) Points whose mean value is less than or equal to the grand mean. The pit at point 26 was excluded.

(2) Points whose mean value is greater than the grand mean. Readings greater than 780 mils were set to "missing."

Points with Mean Less than Grand Mean

(1) The regression is not statistically significant.

(2) The 15-point subsets are normally distributed.

(3) Analysis of Variance shows that there is not a significant difference between the means of the subsets except for the May 1992 subset being significantly thicker than the March 1990 subset.

(4) There is no indication of statistically significant corrosion during this period.

Points with Mean Greater than Grand Mean

(1) The regression is not statistically significant.

(2) The subsets are all normally distributed.

(3) Analysis of Variance indicates that there is a significant difference between some of the means. The greater difference is about 11 mils between May 1992 mean (770 mils) and the March 1990 mean (759) and September 1994 mean (758.6). This appears to be random since May 1992 falls between the other two dates.

(4) There is no indication of statistically significant corrosion during this period.

Pit at Point 26

The mean of the nine measurements at point 26 is 647.4 ±1.8 mils with a maximum of 656.0 and a minimum of 638.0 mils.

(1) The regression is not statistically significant.

(2) The measurements are normally distributed.

There is no indication that this point is corroding more rapidly than the overall grid.

5.3 **6" x 6" Grids at Elevation 51'-10"**

5.3.1 **Bay 13 Area 32: 4/26/90 to 9/14/96**

Eight 49-point data sets were available for this period.

The data are not normally distributed. This is due to a "T" shaped corrosion patch along the right edge and across the center. Examination of the Normal Probability Plot from the Univariate Analysis reveals the following distinct populations:

(1) Four pits at points 20, 23, 25 and 28. The pits at 23 and 28 are statistically significant.

(2) A group of 13 readings with a mean of less than 709 mils.

(3) A group of 31 readings with a mean equal to or greater than 709 mils.

(4) Two outliers with high readings (732 mils @ Point 34 on 4/26/90 and 736 mils @ point 33 on 2/23/91).

(5) The 5/23/91 reading of 660 mils at point 11 is much less than other readings at this point. If this point were included in the analysis, it would have a major impact on the calculated mean corrosion rate.

The two subsets (2 & 3 above) were used to analyze the corrosion rate.

Points With Mean Less than 709 Mils

(1) The regression is not statistically significant.

(2) These subsets are normally distributed.

(3) Analysis of Variance shows that there is not a significant difference between the means of the subsets.

(4) There is no indication of statistically significant corrosion during this period.

Points With Mean Greater than or Equal To 709 Mils

(1) The subsets are normally distributed except for May 1992 which has a three-peak distribution.

(2) Analysis of Variance shows that there is a significant difference between the means of some of the subsets. However, there is no significant difference between the mean of the September 1996 subset and the April 1990, February and May 1991 subsets.

(3) The regression is not statistically significant.

(4) Thus, there is no indication of significant corrosion during this period.

Pits at Points 20, 23, 25 and 28

The measurement at these locations are listed below.

	20	23	25	28
4/26/90	628	594	622	558
2/23/91	626	594	621	558
5/23/91	626	592	620	555
11/2/91	630	601	626	563
5/31/92	630	598	621	557
12/08/92	626	603	635	565
9/14/94	623	593	623	556
9/16/96	622	586	618	589

Based on the CHISQUARE Analysis of all points in September 1996, the pits at points 23 and 28 are statistically significant.

Pit at Point 23

The mean of eight measurements at point 23 is 595.1 ±1.9 mils with a maximum of 603.0 and a minimum of 586.0 mils.

(1) The regression is not statistically significant, and has a positive slope.

(2) The measurements are normally distributed.

There is no indication that this point is corroding more rapidly than the overall grid.

Pit at Point 28

The mean of eight measurements at point 28 is 562.6 ±4.0 with a maximum of 589.0 and a minimum of 555.0 mils.

(1) The regression is not statistically significant, and has a positive slope.

(2) The measurements are normally distributed.

There is no indication that this point is corroding more rapidly than the overall grid.

5.4 6" x 6" Grids at 60'-10" Elevation

5.4.1 Bay 1 Area 50-22: 1/93 to 9/16/96

This location was one of the randomly selected locations inspected in April 1991. Three 49-point data sets were available for this period. It was previously determined that there is a significant pit at point 48. This was reconfirmed by the latest dataset. Therefore, the data is analyzed as follows:

(1) The pit at point 48.

(2) The other 48 points.

Points other than the pit @ point 48

(1) The regression is not statistically significant.

(2) The measurements are normally distributed at the 1% level of significance.

Analysis of Variance indicate a significant difference in the means at the 5% level of significance. However, the latest mean does not differ much from the 12/92 mean. Therefore, there is no indication of significant corrosion.

Pit at point 48

The measurement at these locations are listed below.

1/06/93	589
9/14/94	588
9/16/96	573

The mean of the 9/16/96 data for the other 48 points is 692.5 with a standard deviation of ±24.2 mils. From Ref. 3.9 (Table A-7, page T-15), the 99%/99% One-Sided Tolerance Limit is K=3.1. Therefore, the 99%/99% lower bound is 692.5 - 3.1(24) = 618.1 mils. Thus, the pit is significant. However, with minimal difference between the readings, there is no indication of significant corrosion in the pit.

5.5 6" x 6" Grids at 87'-5" Elevation

5.5.1 Bay 9 Area 20: 11/6/87 to 9/16/96

Eleven 49-point data sets were available for this period.

Point 13 in the May 1992 subset is 694 mils. This is an extreme outlier and was deleted from the data set since it cannot be real and would distort the statistics.

(1) The data are normally distributed.

(2) The regression is not statistically significant.

(3) Analysis of variance indicates that there is a significant difference between some of the means. However, the maximum difference over the nine year period is only 17 mils. Thus, the difference is small. Also the minimum and maximum readings are recent, indicating that the difference is not due to corrosion.

(4) There is no indication of significant corrosion during this period.

5.5.2 Bay 13 Area 28: 11/10/87 to 9/16/96

Eleven 49-point data sets were available for this period.

The data sets are not normally distributed. Examination of the data shows that this is due to the seven thinnest points: 1, 2, 22, 25, 26, 36 and 48.

Analysis of Data Without 7 Thinnest Points

(1) The data are normally distributed except for the May 1991 data which has a low reading at point 27.

(2) The regression is not statistically significant.

(3) Analysis of variance indicates that there is a significant difference between some of the means. However, the maximum difference over the nine year period is only 16 mils. Thus, the difference is small and some of the higher readings are recent indicating that the difference is not due to corrosion.

(4) There is no indication of significant corrosion during this period.

Pit at Point 25

The mean of the eleven measurements at point 25 is 564 ±4.4 with a maximum of 612.0 and a minimum of 550.0 mils. The 612.0 mil reading from 5/23/91 is probably due to shifting of the template position and will be dropped from the analysis. The next highest measurement is 579.0 mils.

The pit was analyzed without the May 1991 data point.

(1) The regression is not significant at the 95% confidence level, with an indicated corrosion rate of -3.5 ±1.2 mpy.

(2) The residuals are normally distributed.

(3) The measurements are not normally distributed.

The analysis indicates that the pit is corroding more rapidly than the overall grid.

5.5.3 **Bay 15 Area 31: 11/10/87 to 9/16/96**

Eleven 49-point data sets were available for this period.

(1) Without the pit at points 34 and 35, the data sets are normally distributed at 95% confidence except for the July 1988 and December 1992 data which are normally distributed at 99%.

(2) The regression is not statistically significant at the 95% level of confidence with a corrosion rate of -0.8 ± 0.5 mpy.

(3) The residuals are normally distributed at the 95% level of confidence.

(4) The measurements are normally distributed at the 97% level of confidence.

(5) Analysis of variance shows that there is a significant difference between the 1996 mean and the means of November 1987, 1988, June 1989 and March 1990 data sets.

(6) The data indicate that there may be ongoing corrosion at this location.

Pit at Point 34

The mean of the eleven measurements is 565.0 ±2.0 with a maximum of 576.0 and a minimum of 556.0 mils. The September 1996 measurement at this point is 562 mils.

(1) The regression is not statistically significant.

(2) The measurements are normally distributed.

There is no indication of significant ongoing corrosion at this point.

Pit at Point 35

The mean of the eleven measurements is 609.8 ±9.0 with a maximum of 626 and a minimum of 521 mils. The September 1996 measurement at this point is 521 mils. This is almost 100 mils less than the previous measurement. This point is located immediately adjacent to the pit at point 34. Since the pit at point 34 is not corroding at a high rate, there is no reason to believe that rapid corrosion is occurring at point 35. The probable cause of the low reading is a slight shift in the template position so that the measurement is of a portion of the same pit as point 34.

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VERIFICATION PLAN/SUMMARY SHEET (EP-006)

PLAN

Scope of Verification: Statistical Analysis of Drywell Thickness Data through September 1996

Item No.	Method/Depth of Verification Required	Req'd Compl. Date
1	Verification Plan for Mean Rate of Corrosion I will verify that all data to be analyzed are correct and that all statistical methods that are used for the purpose of calculating the mean corrosion rate are appropriate, conservative, and correctly used and that the results of the calculation are correct and correctly interpreted. I will also ascertain that the documentation is satisfactory.	

Assigned Verification Engineer: S. D. Leshnoff — Qualified per 4.4.1.3.b ☑ Yes ☐ Waived

Justification for Waiver

Section Manager (SM) (sign) [signature] Date 4/16/98

SUMMARY

Summary of verification scope, methods, results and conclusions.

Summary of verification scope for establishing the mean rate of corrosion.

In particular, I have examined the statistical method as regards the chi-squared test to establish random distribution of data in order to use the mean as the description of the data set, the F test for the significance of the regression model, F/Fcrit for the strength of the basis for a predictive regression, F and t tests for the occurrence of other than random changes among the means and between the means of the last two observations.

Conclusions:

The correct statistical methods were consistently employed and the results were consistently properly interpreted. The calculation summary page is an accurate summary of the results. The documentation is satisfactory.

I conclude that the analayis has been conducted correctly.

Also, as mentioned in Sect.4.5.2.5b and Sect. 4.10.2, if the F/Fcrit ratio is equal to 1 or greater, it indicates that the regression model is more appropriate than the mean model. The variation in mean thickness with time cannot be explained solely by the random variations in measurements. Although a ratio of 1 or greater indicates that the regression is significant, as was the case only for Bay 11A, it does not mean that the slope of the regression line is an accurate prediction of the corrosion rate. The ratio should be at least 4 to 5 to consider the slope to be a useful predictor of the corrosion. Because the F ratio is less than 2 for Bay 11A, it is not necessary to predict continuing corrosion damage there.

Based on this evaluation, the calculation is verified to be acceptable.

Verification Engineer (print) S. D. LESHNOFF (sign) S. D. Leshnoff Date 3/27/98

Use additional sheets if necessary

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CALCULATION VERIFICATION CHECKLIST

(Ref. EP-008)

Calc. Title	Calc. No.	Rev.
STATISTICAL ANALYSIS OF DRYWELL THICKNESS THROUGH SEPTEMBER 1996	C-1302-187-8610-030	0
Verification by: (Print Name)	**Section**	**Date**
S.D. LESHNOFF		3/27/98

Place a check mark in the applicable box (Yes, No, N/A) for each item.

"NO" may indicate the design or verification is incomplete requiring a task request be assigned by the responsible Section Manager. The Section Manager shall review each "NO" response to determine if Task Request needs to be prepared.

"N/A" (Not Applicable) does not require any further action by the Verification Engineer.

The Verification Summary (VS) (Exhibit 7A) may be used to outline the Verification Engineer's work or for comments deemed appropriate by the Verification Engineer.

ITEMS	Review Check Design Compliance Yes	No	N/A
Design Input & Data - Were the inputs correctly selected, referenced (latest revision) and incorporated into the calculation?	✓		
Assumptions - Are assumptions necessary to perform the calculation adequately described and reasonable?	✓		
Regulatory Requirements - Are the applicable codes and standards and regulatory requirements, including issue and addenda, properly identified and are their requirements met?			✓
Construction/Operating Experience - Has applicable construction and operating experience been considered?	✓		
Interfaces - Have the design interface requirements been satisfied?			✓
Methods - Was an appropriate calculation method used?	✓		
Output - Is the output reasonable compared to inputs?	✓		
Acceptance Criteria - Are the acceptance criteria incorporated in the calculation sufficient to allow verification that the design requirements have been satisfactorily accomplished?	✓		
Radiation Exposure - Has the calculation properly considered radiation exposure to the public and plant personnel?			✓
Comments:			

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Item No	*Date Received:*	*Source*
AMP-071	9/23/2005	AMP Audit
Topic:	*Status:*	Closed

ASME Section XI, Subsection IWE

Document References:

B.1.27-3

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

(B.1.27-3):In the OCGS AMP B.1.27 discussion of operating experience, the applicant discusses three (3) areas where containment degradation has been observed. These are the upper region of the drywell shell; the sand bed region at the base of the drywell; and the suppression chamber (Torus) and vent system.Sand bed region at the bottom of the drywell - The applicant states that sand was removed and a protective coating was applied to the shell to mitigate further corrosion. The coating is monitored periodically under LRA AMP B.1.33 Protective Coating Monitoring and Maintenance Program. The reader is directed to program B.1.33 for additional details. LRA B.1.33 identifies this coating to be within its scope; the discussion of operating experience in LRA B.1.33 is similar to the discussion of operating experience in LRA B.1.27. Please provide the following information pertaining to aging management of the sand bed region:
(a) At the present time, is monitoring and maintenance of the coating in the sand bed region included in the scope of the current Protective Coating Monitoring and Maintenance Program or is it performed as part of the current IWE program?
(b) Please provide the implementing procedure for this activity, preferably in both hard copy and electronic format.
(c) Does LR aging management of the containment shell in the sand bed region include both the augmented IWE activities (as delineated in question B.1.27-2 above) and the coating monitoring and maintenance activities under B.1.33? If only B.1.33 is credited, please provide the technical basis for concluding that the augmented IWE activities are not necessary.

Assigned To: Ouaou, Ahmed

Response:

a) Monitoring and maintenance of the coating in the former sand bed region is included in the scope of the Protective Coating Monitoring and Maintenance Program (B.1.33)
b) The sand bed region coating is in accordance with specification SP-1302-32-035 and SP-9000-06-003. These documents are included with Program B.1.33.
c) The Protective Coating Monitoring and Maintenance Program is credited for aging management of the sand bed region. It is not included in augmented inspection required by IWE. As stated in IWE program (B.1.27) operating experience, corrective actions that include cleaning and coating of the

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sand bed region implemented in 1992 have arrested corrosion. The coated surfaces were inspected in 1994, 1996, 2000, and 2004. The inspection showed no coating failure or signs or degradation. Thus, the region is not subject to augmented inspection in accordance with IWE-1240. The coating will be inspected every other refueling outage during the period of extended operation consistent with NRC commitments for the current term.

Oyster Creek will also perform periodic UT inspections of the drywell shell thickness in the sand bed region as described in response to NRC Questions AMP-141 and AMP-209.

Oyster Creek will also enhance the Protective Coating Monitoring and Maintenance Program (B.1.33) to require inspection of the coating credited for corrosion (Torus internal, vent system internal, sand bed region external) in accordance with ASME Section XI, Subsection IWE. For details of the enhancements refer to response to NRC Question AMP-188 for details.

Revised response to reference AMP-188, and AMP-209 which contain additional commitments and clarification discussed with NRC Staff on 1/26/2006.

Supplemental information - 4/20/2006
As a result of discussions with NRC Staff on April 20, 2006 Oyster Creek provided supplemental information on torus coating. Refer to AMP-072 response for this information.

LRCR #: 229 ***LRA A.5 Commitment #:***

IR#:

Approvals:

Prepared By:	Ouaou, Ahmed	4/20/2006
Reviewed By:	Muggleston, Kevin	4/20/2006
Approved By:	Warfel, Don	4/20/2006

NRC Acceptance (Date):

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Item No	*Date Received:*	*Source*
AMP-210	1/24/2006	AMP Audit
Topic:	*Status:*	Closed
IWE		

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

Pages 25 through 31 of the PBD present a discussion of the OCGS operating experience.

(8a)The following statements related to drywell corrosion in the sand bed region need further explanation and clarification:
As a result of the presence of water in the sand bed region, extensive UT thickness measurements (about 1000) of the drywell shell were taken to determine if degradation was occurring. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.
Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning found only in these areas?
After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements.
Please describe the concrete surface below the sand that is discussed in paragraph above.
Please provide the following information:
(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster

Creek sand bed region.

Evaluation of UT measurements taken from inside the drywell, in the in the former sand bed region, in 1992, 1994, and 1996 confirmed that corrosion is mitigated. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.
NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

(8b)The following statement related to drywell corrosion above the sand bed region needs further explanation and clarification:

Corrective action for these regions involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specifications reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the drywell shell and the concrete will allow the upper portion of the drywell to meet ASME code requirements.

Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements". Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

(8c)The following statements related to torus degradation need further explanation and clarification: Inspection performed in 2002 found the coating to be in good condition in the vapor area of the Torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function.
While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continues to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between

pits).

Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to 50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Assigned To: Ouaou, Ahmed

Response:

(8a) Question: Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning only in these area?

Response:
This statement was not meant to indicate that water leaks were limited to only a portion of the circumference. The statement is meant to reflect the fact that water leakage was observed coming out of certain sand bed region drains and those locations were suspect of wall thinning.
No. Wall thinning was not limited to the areas where water leakage from the drains was observed. Wall thinning occurred in all areas of the sand bed region based on UT measurements and visual inspection of the area conducted after the sand was removed in 1992. However the degree of wall thinning varied from location to location. For example 60% of the measured locations in the sand bed region (bays 1, 3, 5, 7, 9, and 15) indicate that the average measured drywell shell thickness is nearly the same as the design nominal thickness and that these locations experienced negligible wall thinning; whereas bay 19A experienced approximately 30% reduction in wall thickness.

Question: Please discuss the concrete surface below the sand that is discussed in paragraph above.

Response:
The concrete surface below the sand was intended to be shaped to promote flow toward each of the five sand bed drains. However once the sand was removed it was discovered that the floor was not properly finished and shaped as required to permit proper drainage. There were low points, craters, and rough surfaces that could allow moisture to pool instead of flowing smoothly toward the drains. These concrete surfaces were refurbished to fill low areas, smooth rough surfaces, and coat these surfaces with epoxy coating to promote improved drainage. The drywell shell at juncture of the concrete floor was sealed with an elastomer to prevent water intrusion into the embedded drywell shell.

Question: Please provide the following information:
(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent

with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster Creek sand bed region.

Response:
1. The minimum recorded thickness in the sand bed region from outside inspection is 0.618 inches. The minimum recorded thickness in the sand bed region from inside inspections is 0.603. These minimum recorded thicknesses are isolated local measurement and represent a single point UT measurement. The 0.806 inches thickness provided to the Staff verbally is an average minimum general thickness calculated based on 49 UT measurements taken in an area that is approximately 6"x 6". Thus the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806".

The 0.806" minimum average thickness verbally discussed with the Staff during the AMP audit was recorded in location 19A in 1994. Additional reviews after the audit noted that lower minimum average thickness values were recorded at the same location in 1991 (0.803") and in September 1992 (0.800"). However, the three values are within the tolerance of +/- 0.010" discussed with the Staff.

2. The minimum projected thickness depends on whether the trended data is before or after 1992 as demonstrated by corrosion trends provided in response to NRC Question #AMP-356. For license renewal, using corrosion rate trends after 1992 is appropriate because of corrosion mitigating measures such as removal of the sand and coating of the shell. Then, using corrosion rate trends based on 1992, 1994, and 1996 UT data; and the minimum average thickness measured in 1992 (0.800"), the minimum projected average thickness through 2009 and beyond remains approximately 0.800 inches. The projected minimum thickness during and through the period of extended operation will be reevaluated after UT inspections that will be conducted prior to entering the period of extended operation, and after the periodic UT inspection every 10 years thereafter.

3.The engineering analysis that demonstrated compliance to ASME code requirements was performed in two parts, Stress and Stability Analysis with Sand, and Stress and Stability Analyses without Sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4, were transmitted to the NRC Staff in December 1990 and in 1991 respectively. Index No. 9-3 and 9-4, were revised later to correct errors identified during an internal audit and were resubmitted to the Staff in January 1992 (see attachment 1 & 2). The analyses are briefly described below.

The drywell shell thickness in the sand bed region is based on Stability Analysis without Sand. As described in detail in attachment 1 & 2, the analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not

included in this model because the bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches.

As discussed with the Staff during the AMP audit, the basic approach used in the buckling evaluation follows the methodology outlined in ASME Code Case N-284 revision 0 that was reconciled later with revision 1 of the Code Case. Following the procedure of this Code Case, the allowable compressive stress is evaluated in three steps. In the first step, a theoretical buckling stress is determined, and secondly modified using appropriate capacity and plasticity reduction factors. In the final step, the allowable compressive stress is obtained by dividing the buckling stress calculated in the second step by a safety factor of 2.0 for Design and Level A & B service conditions and 1.67 Level C service conditions.

Using the approach described above, the analysis shows that for the most severe design basis load combinations, the limits of ASME Section III, Subsection NE 3213.10 are fully met. For additional details refer to Attachment 1 & 2.

As described above, the buckling analysis was performed assuming a uniform general thickness of the sand bed region of 0.736 inches. However the UT measurements identified isolated, localized areas where the drywell shell thickness is less than 0.736 inches. Acceptance for these areas was based on engineering calculation C-1302-187-5320-024.

The calculation uses a Local Wall Acceptance Criteria". This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick so long as the small 12" by 12" area is at least 0.536" thick. However the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, the minimum required linear distances between a 12" by 12" area thinner than 0.736" but thicker than 0.536" and another 12" by 12" area thinner than 0.736" but thicker than 0.536" were not provided.

The actual data for two bays (13 and 1) shows that there are more than one 12" by 12" areas thinner than 0.736" but thicker than 0.536". Also the actual data for two bays shows that there are more than one 2 ½'" diameter areas thinner than 0.736" but thicker than 0.490". Acceptance is based on the following evaluation.

The effect of these very local wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load.

To begin the discussion we will describe the buckling of a simply supported cylindrical shell under the influence of lateral pressure and axial load. As described in chapter 11 of the Theory of Elastic Stability, Second Edition, by Timoshenko and Gere, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin walled cylindrical shell both the length and radius would be essentially constants and if

the thickness was changed locally the change would have to be significant and continuous over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This approach can be easily extrapolated to any shell of revolution that would experience both an axial load and lateral pressure as in the case of the drywell. This local lobe buckling is demonstrated in The GE Letter Report "Sandbed Local Thinning and Raising the Fixity Height Analysis" where a 12 x 12 square inch section of the drywell sand bed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell. Therefore, to influence the buckling of a shell the very local areas of reduced thickness would have to be contiguous and of the same thickness. This is also consistent with Code Case 284 in Section –1700 which indicates that the average stress values in the shell should be used for calculating the buckling stress. Therefore, an acceptable distance between areas of reduced thickness is not required for an acceptable buckling analysis except that the area of reduced thickness is small enough not to influence a buckling lobe of the shell. The very local areas of thickness are dispersed over a wide area with varying thickness and as such will have a negligible effect on the buckling response of the drywell. In addition, these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region which is located at the midpoint between two vents.

The acceptance criteria for the thickness of 0.49 inches confined to an area less than 2½ inches in diameter experiencing primary membrane + bending stresses is based on ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE-3213.2 and NE-3213.10. In particular NE-3213.10 limits the meridional distance between openings without reinforcement to 2.5 x (square root of Rt) . Also Paragraph NE-3335.1 only applies to openings in shells that are closer than two times their average diameter.

The implications of these paragraphs are that shell failures at these locations from primary stresses produced by pressure cannot occur provided openings in shells have sufficient reinforcement. The current design pressure of 44 psig for drywell requires a thickness of 0.479 inches in the sand bed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sand bed region exceed the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph are not required for the very local wall thickness evaluation presented in Revision 0 of Calculation C-1302-187-5320-024.

Reviewing the stability analyses provided in both the GE Report 9-4 and the GE Letter Report Sand bed Local Thinning and Raising the Fixity Height Analysis and recognizing that the plate elements in the sand bed region of the model are 3" x 3" it is clear that the circumferential buckling lobes for the drywell are substantially larger than the 2 ½ inch diameter very local wall areas. This combined with the local reinforcement surrounding these local areas indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from the GE Letter Report that a uniform reduction in thickness of 27% to 0.536" over a one square foot area would only create a 9.5% reduction in the load

factor and theoretical buckling stress for the whole drywell resulting in the largest reduction possible. In addition, to the reported result for the 27% reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5% over a one square foot area which only reduced the load factor and theoretical buckling stress by 3.5% for the whole drywell resulting in the largest reduction possible. To bring these results into perspective a review of the NDE reports indicate there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch thickness used in GE Report 9-4 which cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Therefore, to effectively change the buckling margins on the drywell shell in the sand bed region a reduced thickness would have to cover approximately one square foot of shell area at a location in the shell that is most susceptible to buckling with a reduction in thickness greater than 25%. This leads to the conclusion that the buckling of the shell is unaffected by the distance between the very local wall thicknesses, in fact these local areas could be contiguous provided their total area did not exceed one square foot and their average thickness was greater than the thickness analyzed in the GE Letter Report and provided the methodology of Code Case N284 was employed to determine the allowable buckling load for the drywell. Furthermore, all of these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffing effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

The minimum thickness of 0.733" is not correct. The correct minimum thickness is 0.736".

4. The minimum required thickness for the sand bed region is controlled by buckling.

5. We cannot reconcile the difference between the current (lowest measured) of 0.736" in NUREG-1540 and the minimum measured thickness of 0.806 inches we discussed with the Staff. Perhaps the value in NUREG-1540 should be labeled minimum required by the Code, as documented in several correspondences with the Staff, instead of lowest measured. In a letter dated September 15, 1995, GPU provided the Staff a table that lists sand bed region thicknesses. The table indicates that nominal thickness is 1.154". the minimum measured thickness in 1994 is 0.806", and the minimum thickness required by Code is 0.736". These thicknesses are consistent with those discussed with the Staff during the AMP/AMR audit.

Question: NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

Response:

Our review of NUREG-1540, page 2 indicates that the statements appear to be based on 1991, or

1993 GPU commitment to perform periodic UT measurements. In fact UT thickness measurements were taken in the sand bed region from inside the drywell in 1992, and 1994. The trend of the UT measurements indicates that corrosion has been arrested. As results GPU informed NRC in a letter dated September 15, 1995 (ref. 2) that UT measurements will be taken one more time, in 1996, and the epoxy coating will be inspected in 1996 and, as a minimum again in 2000. The UT measurements were taken in 1996, per the commitment, and confirmed corrosion rate trend of 1992 and 1994. The results of 1992, 1994, and 1996 UT measurements were provided to the Staff during the AMP/AMR audits.

In response to GPU September 15, 1995 letter, NRC Staff found the proposed changes to sand bed region commitments (i.e. no additional UT measurements after 1996) reasonable and acceptable. This response is documented in November 1, 1995 Safety Evaluation for the Drywell Monitoring Program.

For license renewal, Oyster Creek was previously committed to perform One-Time UT inspection of the drywell shell in the sand bed region prior to entering the period of extended operation. However, in response to NRC Question #AMP-141, Oyster Creek revised the commitment to perform UT inspections periodically. The initial inspection will be conducted prior to entering the period of extended operation and additional inspections will be conducted every 10 years thereafter. The UT measurements will be taken from inside the drywell at same locations as 1996 UT campaign

(8b) Question: Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements. Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

Response:
The measures taken to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to maintain the ASME code requirements are,
1. Cleared the former sand bed region drains to improve the drainage path.
2. Replaced reactor cavity steel trough drain gasket, which was found to be leaking.
3. Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.
4. Confirmed that the reactor cavity concrete trough drains are not clogged
5. Monitored former sand bed region drains and reactor cavity concrete trough drains for leakage during refueling outages and plant operation.

Oyster Creek is committed to implement these measures during the period of extended operation.

(8c) Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to 50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

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Response:
(1) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, specifies repair requirements for coating defects exposing substrate and fractured blisters showing signs of corrosion. The repairs referred to in the inspection report included fractured blisters, as well as any mechanically damaged areas, which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters would be candidates for repair, not those blisters that remain intact. The number and location of repairs are tabulated in the final inspection report prepared by Underwater Construction Corporation.
(2) Coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001. Several blistered areas included pitting corrosion where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

(3) In addition to blistering, random deficiencies that exposed base metal were identified in the torus immersion region coating (e.g., minor mechanical damage) during the 19R (2002) torus coating inspections. They ranged in size from 1/16" to ½" in diameter. Pitting in these areas was qualitatively evaluated and ranged from less than 10 mils to slightly more than 40 mils in a few isolated cases. Three quantitative pit depth measurements were taken in several locations in the immersion area of Bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to be representative of typical conditions found on the shell.

Prior to 2002 inspection 4 pits greater than 0.040" were identified. The pits depth are 0.058" (1 pit in 1988), 0.05" (2 pits in 1991), and 0.0685" (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found to be acceptable.

(4) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, includes the pit-depth acceptance criteria for rapid evaluation of observed pitting. The acceptance criteria are supported by a calculation C-1302-187-E310-038. Locations that do not meet the pit-depth acceptance criteria are characterized based on the size of the area, center to center distance between corroded areas, the maximum pit depth and location in the Torus based on major structural features. These details are sent to Oyster Creek Engineering for evaluation.

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

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Question: Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Response:
Submersed area:
(a) The nominal Design thickness is 0.385 inches
(b) The as-built thickness is 0.385 inches
(c) The minimum uniform measured thickness is,
0.343 inches - general shell
0.345 inches - shell - ring girders
0.345 inches - shell - saddle flange
0.345 inches - shell - torus straps

(d) The minimum general thickness required to meet ASME Code Acceptance is 0.337 inches.

Technical basis for pitting acceptance criteria included in Specification SP-1302-52-120 is based on engineering calculation C-1302-187-E310-038. At the time of preparation of calculation C-1302-187-E310-038 in 2002 there were no published methods to calculate acceptance standards for locally thinned areas in ASME Section III or Section VIII Pressure Vessel codes. Therefore, the approach in Code Case N-597 was used as guidance in assessing locally thinned areas in the Torus. This is based on the similarity in approaches between Local Thinning Areas described in N597 and Local Primary Stress areas described in Paragraph NE3213.10 of the ASME B&PV Code Section III, particularly small areas of wall thinning which do not exceed 1.0 x (square root of Rt). In addition, the ASME B&PV Code Section III, Subsection NB, Paragraph NB-3630 allows the analysis of pipe systems in accordance with the Vessel Analysis rules described in Paragraph NB-3200 of the same Subsection as an alternate analysis approach. Therefore, the approach used in N597 for local areas of thinning was probably developed using the rules for Local Primary Membrane Stress from paragraph NB-3200 in particular Subparagraph 3213.10. The Local Primary Stress Limits in NB-3213.10 are similar to those discussed in Subsection NE, Paragraph NE-3213.10.

Since the Code Case had not yet been invoked in to the Section XI program, the calculation provided a reconciliation of the results obtained from the code case against the ASME Section III code requirements as discussed above. This reconciliation demonstrated that the approach in N597 used on a pressure vessel such as the Torus would be acceptable since the results are conservative compared to the previous work performed in MPR-953 and Lm(a) (defined in N597 Table- 3622-1) £ (Rmintmin)1/2.

Currently, the maximum pit depth measured in the Torus is a 0.0685" (measured in 1992 in bay 2). It was evaluated as acceptable using the design calculations existing at that time and was not based on Calculation C-1302-187-E310-038. This remains the bounding wall thickness in the Torus. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Section III and VIII Code requirements for the Torus.

NRC Information Request Form

The Torus inspection program is being enhanced per IR 373695 to improve the detail of the acceptance criteria and margin management requirements using the ASME Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If Code Case N-597-1 is required to develop these criteria for future inspections, NRC review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to periodically monitor to verify they remain bounded.

Supplemental information - 04/19/2006.
This supplements response to item 8a(1) above.
The lowest recorded reading was 0.603 in December 1992. A review of the previous readings for the period 1990 thru 1992 and two subsequent readings taken in September 1994 and 1996 show this point should not be considered valid. The average reading for this point taken in 1994 and 1996 was 0.888 inches.

Point 14 in location 17D was the next lowest value of 0.646 inches recorded during the 1994 outage. A review of readings, at this same point, taken during the period from 1990 through 1992 and subsequent reading taken in 1996 are conistent with this value. Thus the minimum recorded thickness in the sand bed region from inside inspections is 0.646 inches, instead of 0.603 inches.

For additional information on torus coating refer to AMP-072.

LRCR #: ***LRA A.5 Commitment #:***

IR#:

Approvals:

Prepared By:	Ouaou, Ahmed	4/20/2006
Reviewed By:	Miller, Mark	4/20/2006
Approved By:	Warfel, Don	4/20/2006

NRC Acceptance (Date):

June 9, 2006

LICENSEE: AmerGen Energy Company, LLC

FACILITY: Oyster Creek Nuclear Generating Station

SUBJECT: SUMMARY OF MEETING HELD ON JUNE 1, 2006, BETWEEN THE U.S. NUCLEAR REGULATORY COMMISSION STAFF AND AMERGEN ENERGY COMPANY, LLC, REPRESENTATIVES TO DISCUSS THE STAFF'S QUESTIONS REGARDING THE DRYWELL SHELL AND THE OYSTER CREEK NUCLEAR GENERATING STATION LICENSE RENEWAL APPLICATION

On June 1, 2006, the U.S. Nuclear Regulatory Commission staff met with members of AmerGen Energy Company, LLC, (the applicant) in a public meeting to discuss the staff's questions regarding the applicant's aging management program for the drywell shell at Oyster Creek Nuclear Generating Station (OCNGS). The staff provided AmerGen the opportunity to ask for clarification concerning the staff's questions. This meeting was conducted to support the staff's review of the license renewal application for the OCNGS. The application was submitted by letter dated July 22, 2005. A telephone conference line was provided, to allow members of the public who could not attend the meeting, an opportunity to participate in the meeting. At the conclusion of the meeting, the staff responded to questions from a State official and members of the public.

The list of attendees is provided in Enclosure 1. The summary of discussion topics are enclosed as Enclosure 2. The meeting was transcribed and a transcript of the meeting is available in the Agencywide Documents Access and Management System under Accession No. ML061580242.

/RA/

Donnie J. Ashley, Project Manager
License Renewal Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-219

Enclosures:
1. List of Attendees
2. Summary of Discussion Topics

cc w/encls: See next page

June 9, 2006

LICENSEE: AmerGen Energy Company, LLC

FACILITY: Oyster Creek Nuclear Generating Station

SUBJECT: SUMMARY OF MEETING HELD ON JUNE 1, 2006, BETWEEN THE U.S. NUCLEAR REGULATORY COMMISSION STAFF AND AMERGEN ENERGY COMPANY, LLC, REPRESENTATIVES TO DISCUSS THE STAFF'S QUESTIONS REGARDING THE DRYWELL SHELL AND THE OYSTER CREEK NUCLEAR GENERATING STATION LICENSE RENEWAL APPLICATION

On June 1, 2006, the U.S. Nuclear Regulatory Commission staff met with members of AmerGen Energy Company, LLC, (the applicant) in a public meeting to discuss the staff's questions regarding the applicant's aging management program for the drywell shell at Oyster Creek Nuclear Generating Station (OCNGS). The staff provided AmerGen the opportunity to ask for clarification concerning the staff's questions. This meeting was conducted to support the staff's review of the license renewal application for the OCNGS. The application was submitted by letter dated July 22, 2005. A telephone conference line was provided, to allow members of the public who could not attend the meeting, an opportunity to participate in the meeting. At the conclusion of the meeting, the staff responded to questions from a State official and members of the public.

The list of attendees is provided in Enclosure 1. The summary of discussion topics are enclosed as Enclosure 2. The meeting was transcribed and a transcript of the meeting is available in the Agencywide Documents Access and Management System under Accession No. ML061580242.

/RA/

Donnie J. Ashley, Project Manager
License Renewal Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-219

Enclosures:
1. List of Atendees
2. Summary of Discussion Topics

cc w/encls: See next page

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Oyster Creek Nuclear Generating Station

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Oyster Creek Nuclear Generating Station

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Mr. Christopher M. Crane
President and Chief Nuclear Officer
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4300 Winfield Road
Warrenville, IL 60555

Oyster Creek Public Meeting Summary dated: June 09, 2006

SUBJECT: SUMMARY OF MEETING HELD ON JUNE 1, 2006, BETWEEN THE U.S. NUCLEAR REGULATORY COMMISSION (NRC) STAFF AND AMERGEN ENERGY COMPANY, LLC, REPRESENTATIVES TO DISCUSS THE STAFF'S QUESTIONS REGARDING THE DRYWELL SHELL AND THE OYSTER CREEK NUCLEAR GENERATING STATION LICENSE RENEWAL APPLICATION

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Attendance List for Meeting
Between the U.S. Nuclear Regulatory Commission Staff
and AmerGen Energy Company, LLC, Representatives

June 1, 2006

Name	Organization
Frank Gillespie	NRC/NRR/DLR
P.T. Kuo	NRC/NRR/DLR
Louise Lund	NRC/NRR/DLR
Donnie J. Ashley	NRC/NRR/DLR
Jim Davis	NRC/NRR/DLR
Kiyoto Tanabe	NRC/NRR/DLR
Tommy Le	NRC/NRR/DLR
Ken Chang	NRC/NRR/DLR
Daniel Merzke	NRC/NRR/DLR
Linh Tran	NRC/NRR/DLR
Michael J. Morgan	NRC/NRR/DLR
Raj Auluck	NRC/NRR/DLR
Maurice Heath	NRC/NRR/DLR
Jonathan Rowley	NRC/NRR/DLR
Kent Howard	NRC/NRR/DLR
Roy Mathew	NRC/NRR/DLR
Noel Dudley	NRC/NRR/DLR
Rebecca Karas	NRC/NRR/DE
Hans Ashar	NRC/NRR/DE
Tomeka Terry	NRC/NRR/DE
Cayetano Santos	NRC/ACRS
Mitzi Young	NRC/OGC
Steve Hamrick	NRC/OGC
Randy Blough	NRC/RI
John Segala	NRC/RI

Name	Organization
Michael Modes	NRC/RI
Bob Shewmaker	NRC/NMSS/SFPO
Herman Graves	NRC/RES
Michael P. Gallagher	Exelon/AmerGen
Fred Polaski	Exelon/AmerGen
Don Warfel	Exelon/AmerGen
Peter Tamberno	Exelon/AmerGen
Howie Ray	Exelon/AmerGen
John Hufnagel	Exelon/AmerGen
Don Silverman	Morgan Lewis/AmerGen
Steven Dolley	Inside NRC/Platts
Paul Gunter	NIRS
Dennis Zannoni	NJDEP
Ron Zak	NJDEP **
Rich Pinney	NJDEP **
Tom Quintenz	Exelon/AmerGen **
Jim Laird	Exelon/AmerGen **
Richard Webster	Rutgers Environmental Law Clinic **
Nick Clunn	Asbury Park Press **
Jeff Brown	GRAMMES **
Paula Gotsch	GRAMMES **
Edith Gbur	Jersey Shore Nuclear Watch **
Don Warren	JSNW **
Peter James Atherton	JSNW **

** Members of the public who participated in the meeting using the teleconference line.

Summary of Discussion Topics Between the U.S. Nuclear Regulatory Commission Staff and AmerGen Energy Company, LLC, Representatives June 1, 2006

On March 10, 2006, the U.S. Nuclear Regulatory Commission issued AmerGen requests for additional information concerning its review of the drywell corrosion time-limited aging analysis (TLAA), which is contained in the Oyster Creek license renewal application Section 4.7.2, "Drywell Corrosion." AmerGen responded to the requests in a letter dated April 7, 2006. On the basis of the AmerGen responses, the NRC requested a meeting to clarify the following issues related to the TLAA.

Uncertainties in Ultrasonic Test (UT) Results:

Attachment 1A of the GPU Nuclear Corporation's letter dated November 26, 1990, contains a statistical evaluation of the UT measurement data taken up to 1990. On the cover page of the report, GPU Nuclear Corporation made a disclaimer that,

> The work is conducted by an individual(s) for use by GPU. Neither GPU nor the authors of the report warrant that the report is complete or accurate.

The NRC requested the applicant to clarify the disclaimer or explain how the UT measurement data were evaluated, and used in the drywell analysis.

Use of ASME Sec. III, Subsection NE-3213.10 for Localized Corroded Areas:

The applicant used the provisions in ASME Code Section III, Subsection NE-3213.10, for areas of localized thinning. This provision, though not directly applicable to the randomly thin areas caused by corrosion, can be used with care and adequate conservatism. The NRC requested the applicant to clarify how NE-3213.10 was applied to the areas of localized thinning.

UT Results Indicating Increased Drywell Shell Thickness:

Information provided by the applicant indicates that the UT measurements taken from inside the drywell after 1992 show a general increase in metal thickness. In at least one case, the increase is as much as 50 mils in a two-year period. The NRC requested the applicant to clarify what steps will be taken to verify the accuracy of UT measurements.

Use of ASME Code Case 284:

The applicant used the methods and assumptions contained in ASME Code Case-284-1 in the buckling analysis of the Drywell shell in the sand-pocket area. The staff has not yet endorsed ASME Code Case 284. The staff does not take exception to the use of average compressive stress across the metal thickness for buckling analysis of the as-built shell. However, if corrosion has reduced the strength of the remaining metal through the cross section, this assumption may not be valid. The NRC requested the applicant to clarify its use of ASME Code Case 284.

Junctions Between Plates of Different Thicknesses:

The UT measurements taken in the spherical portion of the drywell shell adequately represent the upper spherical area. However, there are no measurements taken in the lower portion of the spherical area above the sand-pocket area. To ensure that the spherical portion of the drywell shell is properly represented in the database, additional UT measurements taken approximately at or above the junction of the 0.722 inch and 1.154 inch thick plates would be desirable. Likewise, additional UT measurements taken on the cylindrical portion of the drywell shell at about 71 feet 6 inches (i.e. at the junction of the 0.640 inch plate and the thickened plate in the knuckle area) may be desirable. The NRC requested the applicant to clarify its UT sampling plan in context of the entire drywell shell assessment.

Inspection of Inaccessible Regions:

It is not clear to the NRC whether the junction between the 1.154 inch plate and the 0.676 inch plate at the elevation 6 foot 10¼ inches is represented in the UT sampling plan. This area is below the bottom of the sand-pocket area, and is in contact with the concrete alkaline environment. However in the past, before sealing of the junction between the steel and the concrete, this area would have been subjected to the same type of contaminated water as the drywell shell in the sand-pocket area. The NRC considers this junction to be an area for possible corrosion. The NRC requested the applicant to incorporate this area in the sampling plan or justify why it should not be part of the sampling plan.

Sand Bed Region Inspection Increments:

In a letter dated April 4, 2006, AmerGen committed to perform UT measurements of the sand bed region every 10 years. In view of the uncertainty regarding the long-term effectiveness of the coating and water leakage, the NRC requested the applicant to clarify the commitment for UT measurement frequency in the sand bed region.

AmerGen

An Exelon Company

Michael P. Gallagher, PE
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License Renewal Projects

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20353
June 20, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)

References:

1. NRC's "Request for Additional Information for the Review of the Oyster Creek Nuclear Generating Station, License Renewal Application (TAC 7624)", dated March 10, 2006

2. AmerGen's "Response to NRC Request for Additional Information, dated March 10, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. 7624)," dated April 7, 2006

3. NRC's "Summary of Meeting Held on June 1, 2006, Between the U.S. Nuclear Regulatory Commission Staff and AmerGen Energy Company, LLC Representatives to Discuss the Staff's Questions Regarding the Drywell Shell and the Oyster Creek Nuclear Generating Station License Renewal Application," dated June 9, 2006 (ADAMS # ML061600368)

In Reference 1, as part of its review of the AmerGen Energy Company (AmerGen) application for license renewal for Oyster Creek Generating Station (Oyster Creek), the NRC Staff requested additional information regarding the aging management program and activities associated with the Oyster Creek drywell containment shell. Reference 2 provided AmerGen's response to these RAIs.

On June 1, 2006, the NRC Staff held a public meeting with representatives from AmerGen to further discuss the drywell aging management program. At that meeting, the Staff posed several specific clarifying questions to AmerGen, as documented in Reference 3. Enclosure 1 of this letter provides AmerGen's responses to these questions. For clarity, the questions as provided in Reference 3 are repeated along with AmerGen's responses.

Given this submittal, AmerGen concluded that it was not necessary to have an additional meeting to review this material. Therefore, at AmerGen's request, the Staff cancelled the meeting that had tentatively been scheduled for June 22, 2006.

Enclosure 2 contains a summary of the regulatory commitments being made in this letter. Table A.5 from Appendix A of the License Renewal Application will be updated to reflect these new commitments and submitted on a schedule to support the Staff's processing of the Safety Evaluation Report.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 06-20-2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosures: 1. Supplemental Information Related to Drywell Shell
2. Summary of Commitments

cc: Regional Administrator, USNRC Region I, w/o Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/o Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

Enclosure 1

Supplemental Information Related to Oyster Creek Drywell Shell

June 20, 2006

AmerGen Letter 2130-06-20353

A. Uncertainties in Ultrasonic Test (UT) Results:
Attachment 1A of the GPU Nuclear Corporation's letter dated November 26, 1990, contains a statistical evaluation of the UT measurement data taken up to 1990. On the cover page of the report, GPU Nuclear Corporation made a disclaimer that;

> The work is conducted by an individual(s) for use by GPU. Neither GPU nor the authors of the report warrant that the report is complete or accurate.

The NRC requested the applicant to clarify the disclaimer or explain how the UT measurement data were evaluated, and used in the drywell analysis.

Response:
The disclaimer noted by the NRC staff is on the cover page of Technical Data Report (TDR) No. 948 Rev. 1, "Statistical Analysis of the Drywell Thickness Data". The disclaimer statement is a standard clause that was placed on TDRs developed in accordance with the applicable GPUN procedure at the time. AmerGen points out that TDR No. 1027, which is also a part of Attachment 1A includes the same disclaimer. The disclaimer was intended to reinforce that TDRs are not design basis documents and were not design verified in accordance with the GPUN QA Program.

In this case TDR 948 was developed to summarize the initiative that surveyed the drywell and that assessed initial corrosion rates based on data collected from 1986 through December 1988. However this TDR did not serve as the design basis document, which demonstrated the drywell shell met design basis requirements. The TDR in Section 1 (Introduction/Background) explains that the TDR documents the assumptions, methods and results of the statistical analysis used to evaluate the corrosion rates. The section then states that the complete analysis is documented in calculation C-1302-187-5300-005.

Calculation C-1302-187-5300-005, "Statistical Analysis of Drywell Thickness Data Thru 12-31-88" did serve as the design basis document, which demonstrated the drywell shell met design basis requirements. This calculation was developed and design verified in accordance with the GPUN QA Program and is approximately 200 pages long.

A review of the information contained in the TDR Section 4.6 (Summary of Conclusion) shows that it is consistent with the information in Section 2 (Summary of Results) in calculation C-1302-0187-5300-005. Thus, the information in the TDR No. 948 represents design quality information.

In response to the NRC's question on how the UT measurement data were evaluated and used in the drywell analysis, AmerGen provided a description of how the 49-point array statistical analysis was performed in response to NRC Q&A #AMP-356, item (4). In that response, AmerGen stated that the methodology and acceptance criteria that are applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) are described in engineering specification IS-328227-004 and in calculation No. C-1302-187-5300-011, "Statistical Analysis of Drywell Thickness Data Thru 4-24-90". This calculation is the more recent version of calculation C-1302-187-5300 and has been submitted by AmerGen to the NRC. These two documents were submitted to the NRC in a letter dated November 26, 1990 and provided to the Staff during the AMP/AMR audit. A brief summary of the methodology and acceptance criteria is described below.

The initial locations identified in 1986 and 1987 where corrosion loss was most severe were selected for repeat inspection over time to measure corrosion rates. For locations where the initial investigations found significant wall thinning, UT inspection consisted of 49 individual UT data points equally spaced over a 6"x 6" area. Each new set of 49 values was then tested for normal distribution. If the data was normally distributed, then the mean value of the 49 points was calculated and used to represent the general drywell shell thickness in the tested area. If the

49 points were not normally distributed, then the grid was subdivided into datasets (usually 2, top and bottom) that were normally distributed. The mean value for each dataset was then calculated. The minimum mean value was compared to the minimum required thickness as described below.

The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736 inches. In addition each individual reading was compared to the local minimum required criteria of 0.490 inches. The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to NRC Question #AMP-210.

A decrease in the mean value over time is representative of corrosion. If corrosion does not exist, the mean value will not vary with time, although random variations in the UT measurements as a result of such factors as variables in the inspection process and in environmental conditions may occur.

If corrosion is continuing, the mean thickness will decrease linearly with time. Therefore the curve fit of the data is tested to determine if linear regression is appropriate, in which case the corrosion rate is equal to the slope of the line. If a slope exists, then upper and lower 95% confidence intervals of the curve fit are calculated. The lower 95% confidence interval is then projected into the future and compared to the required minimum uniform thickness criteria of 0.736 inches.

A process similar to that described above is applied to the thinnest individual reading in each grid. The lowest reading taken is also verified against the local minimum thickness requirement. Then the curve fit of the data is tested to determine if linear regression is appropriate. If a slope exists, then the lower 95% confidence interval is then projected into the future and compared to the required minimum local thickness criteria of 0.490 inches.

B. Use of ASME Sec. III, Subsection NE-3213.10 for Localized Corroded Areas:
The applicant used the provisions in ASME Code Section III, Subsection NE-3213.10, for areas of localized thinning. This provision, though not directly applicable to the randomly thin areas caused by corrosion, can be used with care and adequate conservatism. The NRC requested the applicant to clarify how NE-3213.10 was applied to the areas of localized thinning.

Response:
Clarification of how ASME Section III, Subsection NE-3213.10 was applied to the areas of localized thinning was provided in response to NRC RAIs issued in 1991, as a result of the Staff's review of the GE analysis (Ref. 7, and 8). AmerGen is not aware of any new practical engineering analysis methods that can be used as alternatives to ASME Section III, Subsection NE-3213.10 to more accurately reflect the corroded drywell shell. NRC Staff stated during the June 1, 2006 meeting that they are not aware of any such alternatives either.

More recently, AmerGen contracted GE to review the 1991 analysis of the drywell shell performed by GE (Ref. 1, & Ref. 2) for the purpose of identifying conservatism. GE's review is documented in a report prepared by the original author of the analysis (Ref. 9). The GE findings and position are summarized below.

Although the ASME Section III and Section VIII analysis procedures were not developed for randomly thin areas caused by corrosion, GE has concluded that the same analysis procedures are applicable to in-service components as long as the section thickness values used are adjusted to account for the reduction due to corrosion. Table 2-1 of Reference 1 lists the nominal thickness values and the 95% confidence level thickness values in the locally corroded areas. Even though the corroded thickness is present only in a very local area of a region, the reduced value was used for that drywell region in the Section VIII stress analysis.

ASME Section III, Subsection NE-3213.10 states that membrane stress produced by pressure or other mechanical loading and associated with a primary or discontinuity effect produces excessive distortion in the transfer of load to other portions of the structure. Conservatism requires that such stress be classified as a local primary membrane stress even though it has some characteristics of a secondary stress. A stressed region may be considered local if the distance over which the membrane exceeds $1.1S_{mc}$ does not extend in the meridional direction more than 1.0 $\sqrt{(Rt)}$ where S_{mc} is as defined in Subsection NE-3112.4, R is the minimum mid surface radius of curvature and t is the minimum thickness in the region considered. Regions of local primary stress intensity involving axisymmetric membrane distributions which exceed $1.1S_{mc}$ shall not be closer in the meridional direction than 2.5 $\sqrt{(Rt)}$ where R is defined as $(R_1 + R_2)/2$ and t is defined as $(t_1 + t_2)/2$, where t_1 and t_2 are the minimum thicknesses at each of the regions considered and R_1 and R_2 are the minimum midsurface radii of curvature at these regions where the membrane stress intensity exceeds $1.1S_{mc}$.

The requirements of ASME Section III, Subsection NE-3213.10 were satisfied by determining the maximum meridional extent of the areas where the local primary membrane stress exceeds 1.1 Smc, but is below the allowable value of 1.5 Smc [Reference 1]. The maximum extent was determined to be 11 inches (using the large displacement solution) and was found to be acceptable [i.e., less than the allowable value of 1.0 $\sqrt{(Rt)}$ or 17.6 inches]. Given that a uniform minimum corroded thickness for a drywell region is used in the evaluation, the preceding analysis is expected to be bounding for the actual corroded condition.

The preceding primary local stress condition was for the case of postulated accident or LOCA condition (load combination number V in Table 2-4 of Reference 1). A peak internal pressure of 62 psi was used in this calculation. This peak pressure was based on the measured peak pressure of 52 psi in Bodega Bay tests with an added pressure of 10 psi. An Oyster Creek-specific calculation with an adder of 15% showed the peak pressure during a postulated LOCA as 44 psi. This value was approved in 1993 by the NRC per Reference 5. The difference between 62 psi and 44 psi represents conservatism in the calculated value of the local primary membrane stresses in areas of the drywell above the sand bed region.

For the sand bed region, the minimum required general shell thickness of 0.736" is controlled by buckling due to the refueling load condition (Ref. 2). This load condition was considered a service level B and a safety factor of 2.0 was applied against buckling. This factor of safety is associated with plant operation. Since the plant is shutdown during refueling, which only occurs every 2 years, the safety factor of 2 introduces conservatism in the analysis.

Table-1 below presents drywell shell thicknesses (nominal, minimum measured at monitored locations, minimum required to satisfy ASME stress requirements) and the available thickness margin based on the revised drywell design pressure of 44 psi.

Table 1- Drywell Shell Thickness and the Minimum Available Thickness Margin

Drywell Region	Nominal Design Thickness, inches	Minimum Measured Thickness, inches	Minimum Required Thickness, Inches	Minimum Available Thickness Margin, inches
Cylindrical	0.640	0.604	0.452	0.152
Knuckle	2.625	2.54	2.29	0.25
Upper Sphere	0.722	0.676	0.518	0.158
Middle Sphere	0.770	0.682	0.541	0.141
Lower Sphere	1.154	0.800[1]	0.629	0.171
Sand Bed	1.154	0.800	0.736[2]	0.064

1. The general thickness in the lower sphere is conservatively assumed to be the same as the sand bed region
2. The minimum required general thickness in the sand bed region is controlled by buckling analysis, governed by load combinations that do not include the 44 psi pressure.

Based on the data presented in Reference 3, corrosion can reduce uniform elongation that could affect metal response to large plastic strains. However, Reference 3 also stated that to ensure a conservative design (presumably to resolve this concern), it is necessary to keep stresses and strains in corrosion areas from exceeding ASME code allowable limits [last paragraph, Section 6.5]. The stress analysis presented in Reference 1 assured that the code allowable limits are met in the corroded regions.

There is also an inherent conservatism in the primary stress limits specified in the NE-3200 rules for the design of Class MC containment vessels versus the NC-3200 rules for the design of Class 2 vessels. The rules of NE-3300 for the design of Class MC vessels are essentially identical to the NC-3300 rules for the design of Class 2 vessels. However, higher allowable stresses are permitted for the NC-3200 vessels but not for primary stresses in NE-3200 vessels. For example, the allowable basic stress intensity (Sm) for the Oyster Creek drywell material is 23,300 psi if it were used in a NC-3200 vessel versus 19,300 psi for the NE-3200 Class MC containment. The 19,300 psi value is based on a Code minimum ultimate strength of 70 ksi. Although CMTRs for the Oyster Creek drywell were not reviewed, it is reasonable to assume that the actual CMTR values of ultimate strength will be higher than the Code minimum value. This difference would also represent conservatism in the allowable stress values.

Although provisions in ASME Code Section III, Subsection NE-3213.10 are not directly applicable to the randomly thin areas caused by corrosion, AmerGen believes that the provisions are applicable to the analysis of Oyster Creek drywell shell based on the following:

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

- The Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.
- As indicated in Table-1, UT measurements of the drywell shell above the sand bed region show that the measured general thickness contains significant margin. Considering the ongoing corrosion in that region is insignificant, the margin can be applied to offset uncertainties related to surface roughness.
- UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736'" thickness assumed in the buckling analysis by significant margin except in 2 bays, bay 17 and bay 19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074" and 0.064" respectively. Considering that significant additional corrosion is not expected in the sand bed region, the margin can be applied to offset uncertainties related to the surface roughness.

C. UT Results Indicating Increased Drywell Shell Thickness:
Information provided by the applicant indicates that the UT measurements taken from inside the drywell after 1992 show a general increase in metal thickness. In at least one case, the increase is as much as 50 mils in a two-year period. The NRC requested the applicant to clarify what steps will be taken to verify the accuracy of UT measurements.

Response:

AmerGen is providing below a discussion of sensitivities involved with the UT measurement process and how they will be minimized in the future.

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 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.

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

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

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

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

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.

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

j Identification of the Physical Inspection Location. There is a potential that inspection locations may be mislabeled on the data sheets.

The inspection procedures uniquely and clearly identify each inspection location and provide the specific instruction as to the area's location.

k Data Analysis. The above potential variables will be considered in the analysis of the data. The analysis not only determines a mean for each grid or sub-grid, but also the variance of

the means. These variances will be compared to past inspections to ensure consistency. The mean and the variance are compared to the acceptance criteria.

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

D. Use of ASME Code Case 284:

The applicant used the methods and assumptions contained in ASME Code Case-284-1 in the buckling analysis of the Drywell shell in the sand-pocket area. The staff has not yet endorsed ASME Code Case 284. The staff does not take exception to the use of average compressive stress across the metal thickness for buckling analysis of the as-built shell. However, if corrosion has reduced the strength of the remaining metal through the cross section, this assumption may not be valid. The NRC requested the applicant to clarify its use of ASME Code Case 284.

Response:

Although Revision 1 of Code Case 284 had not yet been issued when the Reference 2 report was written, the authors had the benefit of consultation with Dr. Clarence Miller who was the primary author of the revision. Thus, the plasticity correction factors used in the evaluation (in Figure 2-4 of Reference 2) are the same as those in Figure 1610-1 of Code Case 284 Revision 1.

Paragraph 1500 in both revisions allows higher values of capacity reduction factors due to internal pressure by stating, "The influence of internal pressure on a shell structure may reduce the initial imperfections and therefore higher values of capacity reduction factors, α_{ij}, may be acceptable. Justification for higher values of α_{ij} must be given in the design report." The technical approach documented and used in the Reference 2 analysis was reviewed and accepted by Dr. Miller in a report (Reference 4) that is also cited as one of the references in the NUREG/CR-6706 report (Ref. 3).

Thus, the technical approach used in the stability evaluation of Reference 2 is entirely consistent with the guidelines in Revision 1 of Code Case N-284.

In the Reference 6 report, Dr. Miller discussed the applicability of the N-284-1 methods to corroded shells. He indicated that the imperfection limit indicated by a parameter e/t (where 'e' is the eccentricity and 't' is the shell thickness) was assumed as 1.0 in Code Case N-284-1. The imperfections could be from the fabrication process in the case of a new shell or could be from a combination of fabrication and corrosion in the shells already in service. The contribution to e/t parameter from corrosion was defined as follows:

$$(e/t)_{corrosion} = (t_n - t_c)/(2t_c)$$

For the sand bed region, if we assume the minimum general corroded thickness of 0.736 inch and the nominal thickness of 1.154 inches, the $(e/t)_{corrosion}$ works out to be (1.154-0.736)/(2x0.736) or 0.28. However, this does not mean the preceding value of $(e/t)_{corrosion}$ need always be added to the (e/t) value from fabrication. In fact it needs to be subtracted where the fabrication related eccentricity is in the outward radial direction. Since the fabrication related eccentricities are likely randomly distributed and thus are equally like in either direction, the overall net effect of the corrosion-induced eccentricities would be insignificant. Thus, it is concluded that the corrosion on the outside surface of the shell will not introduce eccentricities that would significantly impact the e/t value of 1.0 assumed in Code Case N-284.

The conclusions from the preceding discussion are summarized as follows:

- The stress analysis of Oyster Creek drywell presented in Reference 1 satisfies the local primary stress requirements of NE-3213.10. Conservatism in the allowable primary

stress intensity value, the assumed peak pressure during the LOCA condition and the assumption of local corroded thickness in the entire region of the drywell provide additional structural margin.

- Since the Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.
- The technical approach used in the stability evaluation of the Oyster Creek drywell is consistent with the requirements specified in Code Case N-284, Revision 1. Additional eccentricity produced by shell corrosion in service is expected to be accommodated within the allowable limit for imperfections.
- As indicated in Table-1, UT measurements of the drywell shell above the sand bed region show that the measured general thickness contains significant margin. Considering the ongoing corrosion in that region is insignificant, the margin can be applied to offset uncertainties related to surface roughness.
- UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736'" thickness assumed in the buckling analysis by significant margin except in 2 bays, bay 17 and bay 19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074" and 0.064" respectively. Considering that significant additional corrosion is not expected in the sand bed region, the margin can be applied to offset uncertainties related to the surface roughness.

E. Junctions Between Plates of Different Thicknesses:

The UT measurements taken in the spherical portion of the drywell shell adequately represent the upper spherical area. However, there are no measurements taken in the lower portion of the spherical area above the sand-pocket area. To ensure that the spherical portion of the drywell shell is properly represented in the database, additional UT measurements taken approximately at or above the junction of the 0.722 inch and 1.154 inch thick plates would be desirable. Likewise, additional UT measurements taken on the cylindrical portion of the drywell shell at about 71 feet 6 inches (i.e. at the junction of the 0.640 inch plate and the thickened plate in the knuckle area) may be desirable. The NRC requested the applicant to clarify its UT sampling plan in context of the entire drywell shell assessment.

Response:

A review of the drywell fabrication and installation details show that the welds that attach the 0.770" (the correct thickness is 0.770 inches, not 0.722 inch as indicated in the meeting notes) nominal plates to the 1.154" nominal plates at elevation 23' 6 7/8" are double bevel full penetration welds. The external edge of the 1.154" plates is tapered to 3 to 12 minimum as required by ASME Section VIII, Subsection UW-35, while the internal edge of the 1.154" plates are flush with the 0.770" plates. Thus there are no ledges that could retain water leakage and result in more severe corrosion than in areas included in the inspection program. Also, this joint is located below the equatorial center of the sphere. Therefore, in the event that water may run down the gap between the drywell shell and the concrete wall it would not collect on this joint.

In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing inspections were conducted at 19 locations on either the 1.154" thick plates or on the 0.770" thick plates. The UT measurements were taken on a 6" x 6" grid (49 UTs) at each location. The UT measurement results show that thinning of the plates at these locations is less severe than the areas that are included in the corrosion-monitoring program. For this reason, the transition area was not added to the corrosion-monitoring program.

Based on the above, AmerGen concludes that areas monitored under the drywell corrosion-monitoring program bound the transition (from 1.154" to 0.770" thick plates) area of the drywell shell. Nevertheless, UT measurements will be taken on the 0.770" thick plate, just

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

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

In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing (UT) inspections were conducted at 18 locations on the 2.625" thick knuckle plate and at four (4) locations on the 0.640" thick cylinder plate. The UT measurements were taken on a 6" x 6" grid (49 UTs) at each location. The UT measurement results showed that thinning of the plates at these locations was less severe than the areas that are included in the corrosion-monitoring program. For this reason the knuckle area was not added to the corrosion-monitoring program.

Based on the above, AmerGen concludes that areas monitored under the drywell corrosion-monitoring program bound the knuckle area of the drywell shell. However, UT measurements will be taken above the 2.625" knuckle plate in the 0.640" thick plate prior to entering the period of extended operation. The measurements will be taken at one location using the 6" x 6" grid. A second set of UT measurements will be taken two refueling outages later at the same location. The results of the measurements will be analyzed and evaluated to confirm that the rate of corrosion in the transition is bounded by the rate of corrosion of the monitored areas in the upper region of the drywell. If corrosion in the transition area is found to be greater than areas monitored in the upper region of the drywell, UT inspections in the transition area will be performed on the same frequency as those performed on the upper region of the drywell (every other refueling outage).

F. Inspection of Inaccessible Regions:

It is not clear to the NRC whether the junction between the 1.154 inch plate and the 0.676 inch plate at the elevation 6 foot 10¼ inches is represented in the UT sampling plan. This area is below the bottom of the sand-pocket area, and is in contact with the concrete alkaline environment. However in the past, before sealing of the junction between the steel and the concrete, this area would have been subjected to the same type of contaminated water as the drywell shell in the sand-pocket area. The NRC considers this junction to be an area for possible corrosion. The NRC requested the applicant to incorporate this area in the sampling plan or justify why it should not be part of the sampling plan.

Response:

A review of the drywell construction and fabrication details shows that the drywell skirt is welded to the 1.154 inch thick plate below the sand bed floor before the 1.154" thick plate. This thick plate is welded to the 0.676" plate at elevation 6 foot 101/4 inches. The purpose of the skirt, which is also now embedded in concrete, was to support the drywell during construction. The presence of the skirt prevents moisture intrusion into the 0.676" plate.

Both the 1.154" thick plate and the 0.676" thick plate are embedded in concrete and are inaccessible for inspection as recognized by ASME Section XI, Subsection IWE-1232 and NRC Guidance (NUREG-1801 Rev. 1) for license renewal. These documents credit pressure testing performed in accordance with 10 CFR Part 50 Appendix J, Type A test, for managing aging effects of inaccessible portions of the drywell shell. NUREG-1801 and industry document, EPRI 1002950), indicate that corrosion of embedded steel is not significant if the following conditions are satisfied:

1. Concrete meeting the specifications of ACI 318 or 349 and the guidance of 201.2R was used for the containment shell or liner.
2. The concrete is monitored to ensure that it is free of cracks that provide a path for water seepage to the surface of the containment shell or liner.
3. The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements.
4. Water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

As noted in response to NRC Question #AMR-164, these conditions are satisfied for Oyster Creek. It is recognized the conditions were meant to apply to the drywell shell internal surface below the concrete floor inside the drywell of Mark I containments and liners of other containments. However the conditions are also applicable to the sand bed region of the Oyster Creek containment since the sand was removed in 1992. The concrete floor and the external moisture barrier (seal) are now accessible for visual inspection. Visual inspection of the sand bed floor and moisture barrier is conducted on a frequency of every other refueling outage.

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

<u>Corrosion of the Embedded Drywell Shell prior to 1992.</u>

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

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

salinity of the water decreases the dissolved oxygen content of the water and, thus, reduces the concentration of cathodic reactant present for the corrosion reaction.

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

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

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

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

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

Corrosion of the Embedded Drywell Shell after 1992.

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

1. The general lack of two of the four necessary fundamental parameters necessary for any form of corrosion to occur, an electrolyte, (i.e., moisture) and the cathodic reactant (i.e., oxygen), while only the lack of one fundamental parameter is sufficient to prevent corrosion. Sealing off the embedded steel will prevent any refreshment of moisture in the embedded region and any residual moisture will not support any subsequent corrosion

once all the dissolved oxygen is consumed in the cathodic corrosion reaction. The cessation of the corrosion reaction will occur regardless of the presence of contaminants that may be dissolved in the water (e.g., chloride, sulfate, etc.) since although these impurities can affect the kinetics of the corrosion reaction, they do not participate in the cathodic reduction reaction. Once the cathodic reaction is stopped, corrosion is stopped. Intermittent wetting and aeration of the embedded steel would produce only minimal additional corrosion.

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

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

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

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

AmerGen thus concludes that corrosion monitoring of the sand bed region of the drywell shell is bounding with respect to corrosion that may have occurred on the drywell embedded shell prior to 1992. After 1992 and through the period of extended operation, corrosion of the embedded shell is insignificant because of the mitigative measures implemented and the robust drywell corrosion aging management program.

G. Sand Bed Region Inspection Increments:
In a letter dated April 4, 2006, AmerGen committed to perform UT measurements of the sand bed region every 10 years. In view of the uncertainty regarding the long-term effectiveness of the coating and water leakage, the NRC requested the applicant to clarify the commitment for UT measurement frequency in the sand bed region.

Response:
AmerGen is confident that the aging management program it committed itself to in the April 4, 2006 letter is adequate to ensure that significant drywell corrosion will be detected and addressed prior to impacting the intended function of the containment. The program requires visual inspection of the coating in the sand bed region on a frequency of every other refueling outage.

The program also requires performing UT inspections in the upper regions of the drywell shell on a frequency of every other refueling outage. The measurements in the upper region of the drywell bound the sand bed region since the environment is the same and the sand bed region is protected with epoxy coating while the upper region is coated only with a Zinc primer.

In addition, AmerGen is committed to performing UT examinations of the sand bed region every 10 years. The 10-year frequency for the UT measurements is based on ASME Section XI requirements and is intended to confirm that the coating continues to mitigate corrosion. The initial UT measurements will be taken prior to entering the period of extended operation. The UT measurements are only a part of the overall program designed to provide reasonable assurance that significant corrosion is detected before containment intended function is adversely impacted.

Nevertheless, AmerGen will take a second set of UT measurements in the sand bed region two refueling outages after the measurements taken prior to entering the period of extended operation. The results of the measurements will be evaluated to determine the appropriate measurement frequency required to provide continued reasonable assurance that corrosion is being effectively monitored and managed during the period of extended operation. The frequency will be established as appropriate, but not to exceed every 10 years.

H. In addition to items listed in the June 9, 2006 NRC meeting summary, AmerGen provides additional information on the actions that will be taken if water is detected in the sand bed region drains.

Corrective Actions to be taken if Water is Detected in the Sand Bed Drains

AmerGen will monitor the sand bed region drains on a daily basis during refueling outages and take the following actions if water is detected. The actions will be completed prior to exiting the outage.

a. The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
b. The water will be chemically analyzed to aid in determining the source of leakage.
c. A remote inspection will be performed in the trough drain area to determine if the trough drains are operating properly
d. The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected.
e. If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation will be consistent with the existing program.
f. The degraded coating and/or the seal will be repaired in accordance with station procedures.
g. UT measurements will be taken in the upper region of the drywell consistent with the existing program.

AmerGen will also monitor the sand bed region drains quarterly during the operating cycle. If water is detected, actions listed below will be taken. Actions that require an outage to accomplish (d, e, f, and g), will be completed prior to exiting the next scheduled refueling outage.

a. The leakage rate will be quantified to determine a representative flow rate. The leakage rate will be trended.
b. The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
c. The water will be chemically analyzed to aid in determining the source of leakage.

d. The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected during the next refueling outage or an outage of opportunity.
e. If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation of the results will be consistent with the existing program.
f. UT measurements will be taken in the upper region of the drywell consistent with the existing program.
g. The degraded coating and/or the seal will be repaired in accordance with station procedures.

References

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3. "Capacity of Steel and Concrete Containment Vessels With Corrosion Damage," NUREG/CR-6706, February 2001.
4. Miller, C.D., 1991, "Evaluation of Stability Analysis Methods Used for the Oyster Creek Drywell," Docket No. 50-219, September 12, 1991, CBI Technical Services Company, Report prepared for GPU Nuclear Corporation.
5. Letter from Alexander W. Dromerick of the NRC to John J. Barton of GPU Nuclear Corporation, dated September 13, 1993, subject: Issuance of Amendment No. 165 (TAC No. M81093).
6. Miller, C.D., "Applicability of ASME Code Case N-284-1 to Buckling Analysis of Drywell Shell," June 15, 2006.
7. Letter from Alexander W. Dromerick to John J. Barton (GPU), "Request for Additional Information on Oyster Creek Corroded Drywell Analysis (TAC No. 79166)", dated May 23, 1991. ADAMS Accession #9106030240.
8. Letter from J. C. Devine, Jr. (GPU) to U. S. Nuclear Regulatory Commission, "Oyster Creek Drywell Containment", dated June 20, 1991. ADAMS Accession #9106240280.
9. GE Report, "NRC Question Response Input to AmerGen on Oyster Creek Drywell Structural Evaluations", by Dr. H. S. Mehta, June 2006.

Enclosure 2

Summary of Commitments

June 20, 2006

AmerGen Letter 2130-06-20353

Enclosure 2

Summary of Commitments

The following table identifies the commitments made in this document. Any other actions discussed in this submittal represent intended or planned actions. They are described to the NRC for the NRC's information and are not regulatory commitments.

Commitment	**Committed Date or Outage**	**One-Time Action (Yes/No)**	**Programmatic (Yes/No)**
1. In addition to AmerGen's previous commitment to perform drywell sand bed region Ultrasonic Testing (UT) prior to the period of extended operation (see AmerGen letter 2130-06-20284, dated April 4, 2006), AmerGen will perform additional UT inspection of this area two refueling outages after the initial inspection. Subsequent inspection frequency will then be established as appropriate, not to exceed 10-year intervals.	Two refueling outages subsequent to the next Drywell sand bed UT inspections	No	Yes
2. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).	Prior to the period of extended operation and two refueling outages later	No	Yes

Commitment	Committed Date or Outage	One-Time Action (Yes/No)	Programmatic (Yes/No)
3. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).	Prior to the period of extended operation and two refueling outages later	No	Yes
4. 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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.	Daily during refueling outages	No	Yes

Commitment	Committed Date or Outage	One-Time Action (Yes/No)	Programmatic (Yes/No)
5. The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage: • Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program • Any degraded coating or moisture barrier will be repaired	Quarterly during non-outage periods	No	Yes

Oyster Creek Document Distribution Sheet

TITLE/SUBJECT: **Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)**

COGNIZANT INDIVIDUAL: Fred Polaski

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	05040	2130-06-20353	Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)	6/20/06

AmerGen

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20354
June 23, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Updated FSAR Supplement Information Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)

Reference: AmerGen's "Application for Renewed Operating License," Oyster Creek Generating Station, dated July 22, 2005 (TAC No. MC7624)

In the referenced letter, AmerGen Energy Company, LLC (AmerGen) made application for a renewed operating license for Oyster Creek Generating Station (Oyster Creek). Appendix A to the License Renewal Application (LRA) was the Final Safety Analysis Report (FSAR) Supplement, which provided proposed licensing basis information regarding the aging management programs, time limited aging analyses (TLAAs) and commitments associated with the LRA.

During the course of NRC's review of the Oyster Creek LRA, activities such as NRC Audits and Inspections, Requests for Additional Information and AmerGen decisions to make additional commitments in support of license renewal have impacted the content of the original LRA FSAR Supplement. Therefore, in Enclosure 1, AmerGen provides an update to the LRA Appendix A information, integrating the changes that have occurred since the LRA was submitted in July 2005. To prevent possible confusion, a complete replacement for the content of Appendix A is provided, whether or not individual subsections were affected by review activities.

Part of Appendix A is Table A.5, the License Renewal Commitment List. Accordingly, this list has been updated to incorporate the regulatory commitments made to the NRC during the course the LRA review process.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 06-23-06

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosure: Update to LRA Appendix A Information

cc: Regional Administrator, USNRC Region I, w/o Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/o Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

ENCLOSURE

LRA Appendix A – Updated Information
Pages A-1 through A-89

Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

APPENDIX A FINAL SAFETY ANALYSIS REPORT SUPPLEMENT
TABLE OF CONTENTS

A.0 INTRODUCTION

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a FSAR Supplement. This appendix, which includes the following sections, comprises the FSAR supplement:

- Sections A.0.1 contains a listing of the aging management programs that correspond to NUREG-1801 programs, including the current status of the program.
- Sections A.0.2 contains a listing of the plant specific aging management programs, including the current status of the program.
- Sections A.0.3 contains a listing of the time-limited aging analysis aging management programs, including the current status of the program.
- Section A.1 contains a summarized description of the NUREG-1801 programs for managing the effects of aging.
- Section A.2 contains a summarized description of the plant specific programs for managing the effects of aging.
- Section A.3 contains a summarized description of the NUREG-1801 programs that support the TLAAs.
- Section A.4 contains a summarized description of the Time-Limited Aging Analyses (TLAAs) applicable to the period of extended operation.
- Section A.5 contains the License Renewal Commitment List

The integrated plant assessment for license renewal identified new and existing aging management programs necessary to provide reasonable assurance that systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the period of extended operation. The period of extended operation is defined as 20 years from the unit's current operating license expiration date.

A.0.1 NUREG-1801 AGING MANAGEMENT PROGRAMS

The NUREG-1801 Aging Management Programs (AMPs) are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-1801 or require enhancements.

The following list reflects the status of these programs. Commitments for program additions and enhancements are identified in the appropriate sections.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.1.1) [Existing – Requires Enhancement]

2. Water Chemistry (Section A.1.2) [Existing]

3. Reactor Head Closure Studs (Section A.1.3) [Existing]

4. BWR Vessel ID Attachment Welds (Section A.1.4) [Existing]

5. BWR Feedwater Nozzle (Section A.1.5) [Existing]
6. BWR Control Rod Drive Return Line Nozzle (Section A.1.6) [Existing]
7. BWR Stress Corrosion Cracking (Section A.1.7) [Existing]
8. BWR Penetrations (Section A.1.8) [Existing]
9. BWR Vessel Internals (Section A.1.9) [Existing – Requires Enhancement]
10. Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section A.1.10) [New]
11. Flow-Accelerated Corrosion (Section A.1.11) [Existing]
12. Bolting Integrity (Section A.1.12) [Existing]
13. Bolting Integrity – FRCT (Section A.1.12A) [New]
14. Open-Cycle Cooling Water System (Section A.1.13) [Existing]
15. Closed-Cycle Cooling Water System (Section A.1.14) [Existing – Requires Enhancement]
16. Closed-Cycle Cooling Water System – FRCT (Section A.1.14A) [New]
17. Boraflex Rack Management Program (Section A.1.15) [Existing]
18. Inspection of Overhead Heavy Load and Light Load Related to Refueling) Handling Systems (Section A.1.16) [Existing – Requires Enhancement]
19. Compressed Air Monitoring (Section A.1.17) [Existing]
20. BWR Reactor Water Cleanup System (Section A.1.18) [Existing]
21. Fire Protection (Section A.1.19) [Existing – Requires Enhancement]
22. Fire Water System (Section A.1.20) [Existing – Requires Enhancement]
23. Aboveground Outdoor Tanks (Section A.1.21) [New]
24. Aboveground Outdoor Tanks – FRCT (Section A.1.21A) [New]
25. Fuel Oil Chemistry (Section A.1.22) [Existing – Requires Enhancement]
26. Fuel Oil Chemistry – FRCT (Section A.1.22A) [New]
27. Reactor Vessel Surveillance (Section A.1.23) [Existing – Requires Enhancement]
28. One-Time Inspection (Section A.1.24) [New]
29. One-Time Inspection - FRCT (Section A.1.24A) [New]

30. Selective Leaching of Materials (Section A.1.25) [New]
31. Selective Leaching of Materials - FRCT (Section A.1.25A) [New]
32. Buried Piping Inspection (Section A.1.26) [Existing – Requires Enhancement]
33. Buried Piping Inspection - FRCT (Section A.1.26A) [New]
34. Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply (Section A.1.26B) [New]
35. ASME Section XI, Subsection IWE (Section A.1.27) [Existing]
36. ASME Section XI, Subsection IWF (Section A.1.28) [Existing – Requires Enhancement]
37. 10 CFR Part 50, Appendix J (Section A.1.29) [Existing]
38. Masonry Wall Program (Section A.1.30) [Existing]
39. Structures Monitoring Program (Section A.1.31) [Existing – Requires Enhancement]
40. RG 1.127, Inspection of Water-Control Structures associated With Nuclear Power Plants (Section A.1.32) [Existing – Requires Enhancement]
41. Protective Coating Monitoring and Maintenance Program (Section A.1.33) [Existing]
42. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.1.34) [New]
43. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section A.1.35) [Existing – Requires Enhancement]
44. Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.1.36) [New]
45. Periodic Monitoring of Combustion Turbine – Electrical (Section A.1.37) [New]
46. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT (Section A.1.38) [New]
47. Lubricating Oil Analysis Program – FRCT (Section A.1.39) [New]
48. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.1.40) [New]

A.0.2 PLANT SPECIFIC AGING MANAGEMENT PROGRAMS

The plant specific programs are described in the following sections. The following list reflects the status of these programs. Commitments for program additions and enhancements are identified in the appropriate sections.

1. Periodic Testing of Containment Spray Nozzles (Section A.2.1) [Existing]
2. Lubricating Oil Monitoring Activities (Section A.2.2) [Existing – Requires Enhancement]
3. Generator Stator Water Chemistry Activities (Section A.2.3) [Existing]
4. Periodic Inspection of Ventilation Systems (Section A.2.4) [Existing – Requires Enhancement]
5. Periodic Inspection Program (Section A.2.5) [New]
6. Periodic Inspection Program - FRCT (Section A.2.5A) [New]
7. Wooden Utility Poles Program (Section A.2.6) [New]

A.0.3 TIME-LIMITED AGING ANALYSES AGING MANAGEMENT PROGRAMS

The NUREG-1801 Time-Limited Aging Analyses AMPs are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-1801 or require enhancements. The following list reflects the status of these programs. Commitments for program additions and enhancements are identified in the appropriate sections.

1. Metal Fatigue of Reactor Coolant Pressure Boundary (Section A.3.1) [Existing – Requires Enhancement]
2. Environmental Qualification (EQ) Program (Section A.3.2) [Existing]

A.0.4 TIME-LIMITED AGING ANALYSIS SUMMARY

Summaries of the Time-Limited Aging Analyses applicable to the period of extended operation are included in the following sections.

1. Neutron Embrittlement of the Reactor Vessel and Internals (Section A.4.1)
2. Metal Fatigue of the Reactor Vessel, Internals, and Primary Coolant Boundary Piping and Components (Section A.4.2)
3. Environmental Qualification of Electrical Equipment (EQ) (Section A.4.3)
4. Fatigue of Primary Containment, Attached Piping, and Components (Section A.4.4)
5. Other Plant-Specific TLAAs (Section A.4.5)

A.0.5 QUALITY ASSURANCE PROGRAM AND ADMINISTRATIVE CONTROLS

Oyster Creek Generating Station

The existing Oyster Creek Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, "Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and these elements are applicable to the safety-related and non-safety related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR). In many cases, existing activities were found adequate for managing aging effects during the period of extended operation.

Forked River Combustion Turbine Power Plant

The Oyster Creek CLB credits the Forked River Combustion Turbine power plant, located adjacent to the Oyster Creek site, as the Alternate AC power source utilized to cope with a postulated Station Blackout (SBO) event. The Forked River Combustion Turbine power plant is not owned by AmerGen. Therefore, the Oyster Creek Quality Assurance Program is not implemented for Forked River station activities that are not performed by AmerGen personnel.

For the in-scope portions of the Forked River Combustion Turbine power plant, several aging management programs will be implemented. The Oyster Creek Structures Monitoring Program (B.1.31) scope will be expanded to include the required structural inspections. The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36) program scope will include the required cable testing for the Forked River Combustion Turbine power plant. The Periodic Monitoring of Combustion Turbine Power Plant – Electrical (B.1.37) program will include the required electrical commodity visual inspections for the Forked River Combustion Turbine power plant. The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.40) program scope will include electrical cable connections at the Forked River Combustion Turbine power plant.

The structural aging management program (B.1.31) and the three electrical aging management programs (B.1.36, B.1.37, and B.1.40) applicable to the Forked River Combustion Turbine power plant will be implemented by AmerGen personnel under the existing SBO Agreement between AmerGen and FirstEnergy, utilizing the Oyster Creek 10 CFR 50 Appendix B Quality Assurance Program.

The mechanical aging management programs applicable to the Forked River Combustion Turbine power plant are closely tied to Forked River plant operation and maintenance activities, and therefore the associated aging management activities may be implemented by AmerGen or by the organizations responsible for operation and maintenance of the combustion turbines. In either case, AmerGen will continue oversight activities in accordance with the SBO Agreement. AmerGen will ensure that processes and procedures that address

the aging management program elements of corrective action, confirmation process, and administrative controls, applicable to the non-safety related Forked River Combustion Turbine power plant mechanical systems, structures, and components that are subject to Aging Management Review (AMR), are established prior to the period of extended operation.

A.1 NUREG-1801 AGING MANAGEMENT PROGRAMS

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

A.1.1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing program that consists of periodic volumetric and visual examinations of components for assessment, identification of signs of degradation, and establishment of corrective actions. The inspections will be implemented in accordance with 10 CFR 50.55(a).

For the isolation condensers this program also includes enhancement activities identified in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," lines IV.C1-5 and IV.C1-6. These are new activities in addition to those required by ASME Section XI, Subsections IWB, IWC, and IWD. The isolation condenser test and inspection enhancement activities detect cracking due to stress corrosion cracking or intergranular stress corrosion cracking, and detect loss of material due to general, pitting and crevice corrosion. These enhancement activities verify that significant degradation is not occurring, and therefore that the intended function of the isolation condenser is maintained during the extended period of operation. These enhancement activities consist of temperature and radioactivity monitoring of the shell side water, which will be implemented prior to the period of extended operation, and eddy current testing of the tubes, with inspection (VT or UT) of the tubesheet and channel head, which will be performed during the first ten years of the extended period of operation.

These activities include inspections, and monitoring and trending of results to confirm that again effects are managed.

A.1.2 WATER CHEMISTRY

The Water Chemistry aging management program is an existing program whose activities consist of monitoring and control of water chemistry to manage the aging of piping, piping components, piping elements and heat exchangers that are exposed to treated water to keep peak levels of various contaminants below system-specific limits based on industry-recognized guidelines of BWRVIP-130: "BWR Vessel and Internals Project BWR Water Chemistry Guidelines" for the prevention or mitigation of loss of material, reduction of heat transfer and cracking aging effects. In addition, the water chemistry program is also credited for mitigating loss of material and cracking for components exposed to sodium

pentaborate and boiler treated water environments. To mitigate aging effects on component surfaces the chemistry program are used to control water chemistry for impurities that accelerate corrosion.

A.1.3 REACTOR HEAD CLOSURE STUDS

The Reactor Head Closure Studs aging management program is an existing program that provides for condition monitoring and preventive activities to manage stud cracking. The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Section XI, Table IWB-2500-1 and preventive measures described in Regulatory Guide 1.65, "Materials and Inspection for Reactor Vessel Closure Studs."

A.1.4 BWR VESSEL ID ATTACHMENT WELDS

The BWR Vessel ID Attachment Welds aging management program is an existing program that includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project BWRVIP-48 and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130.

A.1.5 BWR FEEDWATER NOZZLE

The BWR Feedwater Nozzle aging management program is an existing program that provides for monitoring of feedwater nozzles for cracking through station procedures based on the 1995 Edition through 1996 Addendum of ASME Section XI, Subsection IWB, Table IWB 2500-1. The program specifies periodic ultrasonic (UT) inspections of critical regions of the feedwater nozzle. The inspections are performed at intervals not exceeding ten years.

The Oyster Creek Feedwater Nozzle aging management program will be enhanced to implement the recommendations of the BWR Owners Group Licensing Topical Report General Electric (GE) NE-523-A71-0594-A, Revision 1. These enhancements will be implemented prior to entering the period of extended operation.

A.1.6 BWR CONTROL ROD DRIVE RETURN LINE NOZZLE

The BWR Control Rod Drive Return Line nozzle aging management program is an existing program that provides for monitoring of the control rod drive return line nozzle for cracking through station procedures based on ASME Section XI, Subsection IWB, Table IWB 2500-1, augmented by inspections performed in accordance with the inspection recommendations of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." Based on an NRC approved relief request the periodic dye penetrate tests required by NUREG-0619 have been replaced by ultrasonic measurements. The inspections will be performed at intervals not exceeding ten years. Modifications were

made to the control rod drive return line nozzle thermal sleeve to mitigate or prevent thermally induced fatigue cracking.

A.1.7 BWR STRESS CORROSION CRACKING

The BWR Stress Corrosion Cracking aging management program is an existing program based on NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," and its Supplement 1, BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," and ASME Section XI. The scope of the BWR Stress Corrosion Cracking aging management program includes reactor coolant pressure boundary components and piping four inches and larger nominal pipe size made of stainless steel and exposed to reactor coolant above 200°F. The program includes (a) replacements and preventive measures to mitigate mitigates intergranular stress corrosion cracking (IGSCC) and (b) inspections to monitor IGSCC and its effects. Water chemistry is controlled through implementation of the recommendations of BWRVIP-130: "BWR Vessel and Internals Project BWR Water Chemistry Guidelines".

The BWR Stress Corrosion Cracking aging management program will be enhanced to include:

- The program requires that, for those components within the scope of the BWR Stress Corrosion Cracking aging management program, all new and replacement SS materials be low-carbon grades of SS with carbon content limited to 0.035 wt. % maximum and ferrite content limited to 7.5% minimum. This requirement will be added to the Line Specifications for all applicable license renewal systems.

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

A.1.8 BWR PENETRATIONS

The BWR Penetrations aging management program is an existing program that includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP)-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," and BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate Delta-P Inspection and Flaw Evaluation Guidelines," documents and (b) monitoring and control of reactor coolant water chemistry in accordance with industry-recognized guidelines of BWRVIP-130: "BWR Vessel and Internals Project BWR Water Chemistry Guidelines," to ensure the long-term integrity and safe operation of boiling water reactor vessel internal components. The requirements of ASME Section XI will be implemented in accordance with 10 CFR 50.55(a).

A.1.9 BWR VESSEL INTERNALS

The BWR Vessel Internals aging management program is an existing program that mitigates the effects of stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), and irradiation assisted stress corrosion cracking (IASCC) in reactor pressure vessel internals through water chemistry activities that are implemented through station procedures and are consistent with the guidelines of BWRVIP-130: " BWR Vessel and Internals Project BWR Water Chemistry Guidelines". The program also manages the integrity of reactor pressure vessel internals through condition monitoring activities that consist of examinations implemented through station procedures consistent with the recommendations of the BWRVIP guidelines, as well as the requirements of ASME Section XI.

The BWR Vessel Internals program at Oyster Creek is consistent with the guidelines contained in BWRVIP-94, "BWR Vessel and Internals Project, Program Implementation Guideline." Inspections and evaluations of reactor components are consistent with the guidelines provided in the following BWRVIP reports:

- BWRVIP-18-A, BWR Core Spray Inspection and Flaw Guidelines
- BWRVIP-25, BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26, BWR Top guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-27-A, BWRVIP Standby Liquid Control System/Core Spray/ Core Plate ΔP Inspection and Flaw Evaluation Guidelines.
- BWRVIP-38, BWR Shroud Support Inspection and Flaw Evaluation guidelines
- BWRVIP-47, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
- BWRVIP-48, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines.
- BWRVIP-49-A, Instrument Penetration Inspection and Flaw Evaluation Guidelines.
- BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines.
- BWRVIP-76, BWR Core Shroud Inspection and Flaw Evaluation Guidelines
- BWRVIP-104," Evaluation and Recommendations to Address Shroud Support Cracking in BWRs"

The program will be enhanced to include inspection of the steam dryer in accordance with BWRVIP-139. The program will also be enhanced to inspect the top guide as recommended in NUREG-1801. In addition, the program will be revised to include rolling of the CRD stub tubes as a permanent repair, once the NRC approves the ASME code case (Draft Code Case N-730). If Code Case N-730 is not approved, Oyster Creek will develop a permanent ASME code repair plan. This permanent ASME code repair could be performed in accordance with BWRVIP-58-A, which has been approved by the NRC, or an alternate ASME code repair plan that would be submitted for prior NRC approval. If it is determined that the repair plan needs prior NRC approval, Oyster Creek will submit the repair plan two years before entering the period of extended operation. After the implementation of an approved permanent roll repair, if there

is a leak in a CRD stub tube, Oyster Creek will weld repair any leaking CRD stub tubes during the extended period of operation by implementing a permanent NRC approved ASME Code repair for leaking stub tubes that cannot be made leak tight using a roll expansion method, prior to restarting the plant.

Oyster Creek will revise its Reactor internals program to also manage the aging effect of loss of material due to the aging mechanisms of pitting and crevice corrosion for Reactor Internals.

Oyster Creek will comply with all the applicable requirements that will be specified in the staff's final safety evaluations (SEs) of the BWRVIP-76 and BWRVIP-104 reports, and that it will complete all the license renewal action items in the final SE applicable to Oyster Creek, when they are issued.

The Reactor Internals program will be enhanced to include inspection for loss of material for the feedwater sparger, steam separator, RPV surveillance capsule holders and baffle plate.

The Reactor Internals Program will be enhanced to include and document the condition of the CRD and Feedwater Nozzle thermal sleeves to ensure future inspections look for thermal sleeve bypass flow.

AmerGen/Exelon is committed to following BWRVIP guidelines:

- Oyster Creek will inform the (NRC) staff of any decision to not fully implement a BWRVIP guidelines approved by the staff within 45 days of the report
- Oyster Creek will notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP report.
- Oyster Creek will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP report.

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

A.1.10 THERMAL AGING AND NEUTRON IRRADIATION EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless steel (CASS) aging management program is a new program that will provide for aging management of CASS reactor internal components within the scope of license renewal. The program will be implemented prior to the period of extended operation.

The program will include a component specific evaluation of the loss of fracture toughness in accordance with the criteria specified in NUREG 1801, XI.M13. For those components where loss of fracture toughness may affect function of the component, a supplemental inspection will be performed. This inspection will

ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.

A.1.11 FLOW-ACCELERATED CORROSION

The Flow-Accelerated Corrosion (FAC) aging management program is an existing program based on EPRI guidelines in NSAC-202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program." The program predicts, detects, and monitors wall thinning in piping, fittings, valve bodies, and Feedwater Heaters due to FAC. Analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to FAC are used to predict the amount of wall thinning in pipes, fittings, and Feedwater Heater shells. Program activities include analyses to determine critical locations, baseline inspections to determine the extent of thinning at these critical locations, and follow-up inspections to confirm the predictions. Repairs and replacements are performed as necessary.

A.1.12 BOLTING INTEGRITY

The Bolting Integrity aging management program is an existing program that incorporates industry recommendations of EPRI NP 5769, "Degradation and Failure of Bolting in Nuclear Power Plants," and includes periodic visual inspections of closure bolting for loss of bolting function. Inspection of Class 1, 2, and 3 components is conducted in accordance with ASME Section XI. The requirements of ASME Section XI will be implemented in accordance with 10 CFR 50.55(a). The Oyster Creek program addresses the guidance contained in EPRI TR-104213, Bolted Joint Maintenance & Applications Guide, however the report is not specifically cited as a reference in the Exelon corporate or stations' specific bolted joint inspection/repair procedures. Site procedures will be enhanced to include reference to EPRI TR-104213, Bolted Joint Maintenance & Application Guide, December 1995. Non-ASME Class 1, 2 and 3 bolted joint inspections rely on detection of visible leakage during maintenance or routine observation.

The Bolting Integrity program does not address Primary Containment pressure retaining, structural and component support bolting. Primary Containment pressure retaining bolting are addressed by ASME Section XI, Subsection IWE, B.1.27. The Structures Monitoring Program, B.1.31 addresses the aging management of structural bolting. The ASME Section XI, Subsection IWF program, B.1.28, addresses aging management of ASME Section XI Class 1, 2, and 3 and Class MC support members.

A.1.12A BOLTING INTEGRITY - FRCT

The Bolting Integrity - FRCT aging management program is a new program that provides for condition monitoring of bolts and bolted joints within the scope of license renewal at the Forked River Combustion Turbine power plant. The Forked River Combustion Turbine power plant was originally designed and

supplied by General Electric Company. This program is based on the General Electric recommendations for proper bolting material selection, lubrication, preload application, installation and maintenance associated with the combustion turbine units and auxiliary systems. The program also includes periodic walkdown inspections for bolting degradation or bolted joint leakage at a frequency of at least once every four years. The program manages the loss of material and loss of preload aging effects. This new program will be implemented prior to entering the period of extended operation.

A.1.13 OPEN-CYCLE COOLING WATER SYSTEM

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer and are exposed to raw water - salt water at Oyster Creek. Program activities include (a) surveillance and control of biofouling (including biocide injection), (b) verification of heat transfer capabilities for components cooled by the Service Water and Emergency Service Water systems, (c) inspection and maintenance activities, (d) walkdown inspections, and (e) review of maintenance, operating and training practices and procedures. Inspections may include visual, UT, and Eddy Current Testing (ECT) methods. The program will be enhanced to include specificity on inspection of heat exchangers for loss of material due to general, pitting, crevice, galvanic and microbiologically influenced corrosion in the RBCCW, TBCCW and Containment Spray preventative maintenance tasks. Additionally, the program will be enhanced to include volumetric inspections, for piping that has been replaced, at a minimum of 4 aboveground locations every 4 years based on the observed and anticipated performance of the new pipe. Enhancements to the program will be implemented prior to entering the period of extended operation. The OCCWS aging management program is based on the recommendations of NRC Generic Letter 89-13.

A.1.14 CLOSED-CYCLE COOLING WATER SYSTEM

The Closed-Cycle Cooling Water System aging management program is an existing program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer and are exposed to a closed cooling water environment at Oyster Creek. The Closed-Cycle Cooling Water System aging management program relies on preventive measures to minimize corrosion by maintaining inhibitors and by performing non-chemistry monitoring consisting of inspection and nondestructive examinations (NDEs) based on industry-recognized guidelines of EPRI 1007820, "Closed Cooling Water Chemistry Guidelines," for closed-cycle cooling water systems. Station maintenance inspections and NDE provide condition monitoring of heat exchangers exposed to closed-cycle cooling water environments.

A.1.14A CLOSED-CYCLE COOLING WATER SYSTEM – FRCT

The Closed-Cycle Cooling Water System – FRCT aging management program is a new program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and cracking, and are exposed to a closed cooling water environment at the Forked River Combustion Turbine power plant. The Closed-Cycle Cooling Water System – FRCT aging management program relies on preventive measures to minimize corrosion by maintaining water chemistry control parameters and by performing system monitoring and maintenance inspection activities to confirm that the aging effects are adequately managed. Chemistry control, performance monitoring and inspection activities are based on industry-recognized guidelines of EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines," for closed-cycle cooling water systems.

Chemical control parameters will be monitored by annual water chemistry sampling. System operational monitoring activities will be performed at a frequency of at least once every six months. This new program will be implemented prior to entering the period of extended operation.

A.1.15 BORAFLEX RACK MANAGEMENT PROGRAM

The Boraflex Rack Management Program is an existing program that provides for aging management of the Boraflex neutron poison material. The program consists of monitoring the condition of Boraflex by routinely sampling fuel pool silica levels, periodically trending the condition of Boraflex using RACKLIFE, and periodically performing in-situ measurement of boron-10 areal density using the BADGER device. The BADGER device test is conducted every 3 years.

A.1.16 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is an existing program that confirms the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes and hoists. Administrative controls ensure that only allowable loads are handled. As discussed in Crane Load Cycle Limit time-limited aging analysis (TLAA), the projected number of load cycles for 60 years is significantly lower than the design value and thus fatigue is not a concern for cranes during the period of extended operation. Cranes and hoists structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system are visually inspected periodically for loss of material. Bolting is also monitored for loss of preload by inspecting for missing, detached, or loosened bolts. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied to bolting.

Prior to the period of extended operation, the scope of the program will be enhanced to include additional hoists that have been identified as being in scope for license renewal per 10CFR54.4(a)(2). The program will also be enhanced to

include inspections for rail wear, and loss of material, due to corrosion, of crane and hoist structural components.

A.1.17 COMPRESSED AIR MONITORING

The Compressed Air Monitoring aging management program is an existing program that consists of inspection, monitoring, and testing; including (1) pressure decay testing and visual inspections of system components; and (2) preventive monitoring that checks air quality at various locations in the system to ensure that dewpoint, particulates, and suspended hydrocarbons are kept within the specified limits. This program is consistent with responses to NRC Generic Letter 88-14 and incorporates ISA-S7.0.01-1996, "Quality Standard for Instrument Air."

A.1.18 BWR REACTOR WATER CLEANUP SYSTEM

The BWR Reactor Water Cleanup System aging management program is an existing program that describes the requirements for augmented inservice inspection (ISI) for stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on stainless steel Reactor Water Cleanup System piping welds outboard of the second containment isolation valves. The program includes inspection guidelines delineated in NUREG-0313, Rev. 2 and NRC Generic Letter (GL) 88-01. The program also provides for water chemistry control in accordance with BWRVIP-130: "BWR Vessel and Internals Project BWR Water Chemistry Guidelines" to minimize the potential of crack initiation and growth due to SCC or IGSCC.

In accordance with Generic Letter (GL) 88-01, Supplement 1, upgrades and enhancements have been implemented to the RWCU isolation valves in accordance with Generic Letter 89-10 to ensure that the valves will produce sufficient thrust to perform their design basis function, which is the isolation of containment in the event of a pipe break downstream of the valves. Based on these upgrades/enhancements, an effective Hydrogen Water Chemistry program, and the complete lack of cracking found during any of the RWCU piping weld inspections under Generic Letter 88-01, all inspection requirements for the portion of the RWCU System outboard of the second containment isolation valves have been eliminated.

Reactor coolant system (RCS) chemistry activities that support the aging management program for the RWCU System consist of preventive measures that are used to manage cracking in license renewal components exposed to reactor water and steam. RCS chemistry activities provide for monitoring and controlling RCS water chemistry using Oyster Creek procedures and processes based on BWRVIP-130: "BWR Vessel and Internals Project BWR Water Chemistry Guidelines." The BWR Water Chemistry Guidelines include information to develop proactive plant-specific water chemistry programs to minimize IGSCC.

A.1.19 FIRE PROTECTION

The Fire Protection aging management program is an existing program that includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire wraps, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The program includes surveillance tests of fuel oil systems for the diesel-driven fire pumps to ensure that the fuel supply lines can perform intended functions. The program also includes visual inspections and periodic operability tests of halon and carbon dioxide fire suppression systems based on NFPA codes.

The Fire Protection aging management program will be enhanced to include:

- Specific fuel supply inspection criteria for fire pumps during tests
- Inspection of external surfaces of the halon and carbon dioxide fire suppression systems
- Additional inspection criteria for degradation of fire barrier walls, ceilings, and floors
- Criteria for biennial inspection of clearances for fire doors in the scope of license renewal

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

A.1.20 FIRE WATER SYSTEM

The Fire Water System aging management program is an existing program that provides for system pressure monitoring, fire system header flow testing, pump performance testing, hydrant flushing, water sampling and visual inspections activities. System flow tests measure hydraulic resistance and compare results with previous testing, as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion or fouling would be detected in a timely manner. Pump performance tests, hydrant flushing and system inspections are performed in accordance with applicable NFPA standards. A motor driven pump normally maintains fire water system pressure. Significant leakage (exceeding the capacity of this pump) would be identified by automatic start of the diesel driven fire pumps, which would initiate immediate investigation and corrective action.

The program will be enhanced to include sprinkler head testing in accordance with NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." Samples will be submitted to a testing laboratory prior to being in service 50 years. This testing will be repeated at intervals not exceeding 10 years.

Prior to the period of extended operation, the program will be enhanced to include water sampling for the presence of MIC at an interval not to exceed 5 years, periodic non-intrusive wall thickness measurements of selected portions of

the fire water system at an interval not to exceed every 10 years, and visual inspection of the redundant fire water storage tank heater during tank internal inspections.

A.1.21 ABOVEGROUND OUTDOOR TANKS

The Aboveground Outdoor Tanks aging management program is a new program that will manage corrosion of outdoor carbon steel and aluminum tanks. Paint is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint and any resulting metal degradation of carbon steel tanks or the unpainted aluminum tank. The in scope carbon steel tanks are both supported by structural steel and by earthen or concrete foundations. The aluminum tank is supported by an earthen foundation. Therefore, inspection of the sealant or caulking at the tank-foundation interface, and UT inspection of inaccessible tank bottoms apply only to those tanks on earthen and concrete pads. Removal of insulation will permit visual inspection of insulated tank surfaces and caulking. This new inspection program will be implemented prior to the period of extended operation.

A.1.21A ABOVEGROUND STEEL TANKS – FRCT

The Aboveground Steel Tanks - FRCT aging management program is a new program that will manage corrosion of aboveground outdoor steel tanks. Paint coating is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint coating and any resulting metal degradation of tank external surfaces. The aboveground tanks external surfaces will be visually inspected for coating degradation by walkdown at least once every two years. The Main Fuel Oil storage tank is supported on a concrete foundation. This tank does not have caulking or sealing around the tank-foundation interface. All other in-scope outdoor tanks are supported by structural steel. Therefore, inspection of sealant or caulking at the tank-foundation interface does not apply to the Aboveground Steel Tanks – FRCT aging management program.

The Main Fuel Oil tank bottom is in contact with concrete and soil, and is inaccessible for visual inspection. Therefore, the program includes periodic Non-destructive wall-thickness examinations of the Main Fuel Oil tank bottom to verify that significant corrosion is not occurring.

This program, including the initial tank external paint inspections, will be implemented prior to the period of extended operation. The recommended UT inspection of the Main Fuel Oil tank bottom was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections, and subsequent repairs to the tank floor, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional UT inspections of the tank floor are not necessary prior to entering the period of extended operation and will be performed prior to October 2020.

A.1.22 FUEL OIL CHEMISTRY

The Fuel Oil Chemistry aging management program is an existing program that includes preventive activities to provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of Licensing Renewal. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing and Materials (ASTM). Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel and stored fuel. Fuel oil tanks are periodically drained of accumulated water and sediment. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations. The Fuel Oil Chemistry aging management program will be enhanced to include:

- Routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on fuel oil samples from the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank.
- Analysis for particulate contamination using modified ASTM D 2276-00 Method A on new fuel oil.
- Analysis for water and sediment using ASTM D 2709-96 for Fire Pond Diesel Fuel Tank bottom samples.
- Analysis for bacteria to verify the effectiveness of biocide addition in the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank.
- Periodic draining, cleaning, and inspection of the Fire Pond Diesel Fuel Tanks and the Main Fuel Oil Tank. Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of corrosion or pitting.
- One-time internal inspection of the Emergency Diesel Generator Day tanks to confirm the absence of aging effects.

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

A.1.22A FUEL OIL CHEMISTRY – FRCT

The Fuel Oil Chemistry - FRCT aging management program is a new program that provides assurance that contaminants are maintained at acceptable levels in new and stored fuel oil for systems and components within the scope of Licensing Renewal. The Fuel Oil Storage Tank will be maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing Materials (ASTM). Fuel oil sampling activities will be in accordance with ASTM D 4057 for multilevel and tank bottom sampling. Fuel oil will be periodically sampled and analyzed for particulate contamination in accordance with modified ASTM Standard D 2276 Method A or ASTM Standard D 6217, and, for the presence of water and sediment in accordance with ASTM Standard D 2709 or ASTM Standard D 1796. The Fuel Oil Storage Tank will be

periodically drained of accumulated water and sediment and will be periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations.

This new program will be implemented prior to entering the period of extended operation. The internal inspection of the Main Fuel Oil tank was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections and repairs, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional internal inspections of the tank floor are not necessary prior to entering the period of extended operation and will be performed prior to October 2020.

A.1.23 REACTOR VESSEL SURVEILLANCE

The Oyster Creek Reactor Vessel Surveillance aging management program is an existing program that monitors the effects of neutron embrittlement on the reactor vessel beltline materials. The program is based on the BWR Integrated Surveillance Program (ISP) and satisfies the requirements of 10 CFR 50, Appendix H. The Reactor Vessel Surveillance program is based upon BWRVIP-78, "BWR Vessel and Internals Project: BWR Integrated Surveillance Program Plan", and BWRVIP-86-A, "BWR Vessel and Internals Project Updated BWR Integrated Surveillance Program (ISP) Implementation Plan". The program will ensure coupon availability during the period of extended operation by saving withdrawn coupons for future reconstitution.

Oyster Creek will enhance the program to implement BWRVIP-116 "Integrated Surveillance Program (ISP) Implementation for License Renewal," if approved by the NRC. If BWRVIP-116 is not approved, Exelon will provide a plant-specific surveillance plan for the license renewal period in accordance with 10 CFR 50, Appendices G and H prior to entering the period of extended operation.

BWRVIP ISP as specified in BWRVIP-116, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal" and approved by the staff will be implemented. If the ISP is not approved two years prior to the commencement of the extended period of operation, a plant-specific surveillance program for Oyster Creek will be submitted.

If the Oyster Creek standby capsule is removed from the RPV without the intent to test it, the capsule will be stored in a manner that maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary.

A.1.24 ONE-TIME INSPECTION

The Oyster Creek One-Time Inspection aging management program is a new program that will address potentially long incubation periods for certain aging effects and will provide a means of confirming that an aging effect is either not

occurring or is progressing so slowly as to not have an effect on the intended function of a structure or component within the extended period of operation. The One-Time Inspection program will provide measures to verify that an aging management program is not needed, confirms the effectiveness of existing activities, or determines that degradation is occurring which will require evaluation and corrective action.

This program will be used for the following:

- To confirm crack initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or thermal and mechanical loading is not occurring in Class 1 piping less than four-inch nominal pipe size (NPS) exposed to reactor coolant. Inspections will include UT examination of 10% of the total small bore Class 1 butt welds and destructive or non-destructive examination of a single small bore Class 1 socket welded connection.

- To confirm the effectiveness of the Water Chemistry program to manage the loss of material and crack initiation and growth aging effects. Included in the scope of this activity, a one-time UT inspection of the "B" Isolation Condenser shell below the waterline will be conducted looking for pitting corrosion.

- To confirm the effectiveness of the Closed Cycle Cooling Water System program to manage the loss of material aging effect.

- To confirm the effectiveness of the Fuel Oil Chemistry program and Lubricating Oil Monitoring Activities program to manage the loss of material aging effect.

- To confirm loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment.

- To confirm loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment.

- To confirm loss of material is insignificant for non-safety related (NSR) piping, piping components, and piping elements of vents and drains, floor and equipment drains, and other systems and components that could contain a fluid, and, are in scope for 10CFR54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities.

- Two stainless steel pipe sections in a stagnant or low flow area in the Reactor Water Cleanup System, and two stainless steel pipe sections in a stagnant or low flow area in the Isolation Condenser System will be included in the one-time inspection samples for stress corrosion cracking.

The inspections will be implemented prior to the period of extended operation to manage the effects of aging for selected components within the scope of license renewal.

A.1.24A ONE-TIME INSPECTION – FRCT

The One-Time Inspection – FRCT aging management program is a new program that will provide a means of confirming the aging effects of loss of material and loss of heat transfer are either not occurring or are progressing so slowly as to not have an effect on the intended function of the Combustion Turbine fuel oil and lubricating oil system components within the period of extended operation. Additionally this program will address potentially long incubation periods for loss of material and loss of heat transfer aging effects. The One-Time Inspection – FRCT program will provide measures to verify that an aging management program is not needed, confirms the effectiveness of existing activities, or determines that degradation is occurring which will require evaluation and corrective action. The program will be implemented prior to the period of extended operation.

Inspection methods will include visual examination or volumetric examinations. Inspections will be performed by qualified personnel using procedures developed consistent with the quality classification of the Forked River Combustion Turbines. Acceptance criteria will be in accordance with design standards for the combustion turbines and manufacturer's recommendations. The One-Time Inspection – FRCT program provides for the evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. Should aging effects be detected, the program will initiate actions to characterize the nature and extent of the aging effect and determines what subsequent monitoring is needed to ensure intended functions are maintained during the period of extended operation.

A.1.25 SELECTIVE LEACHING OF MATERIALS

The Selective Leaching of Materials aging management program is a new program that will consist of inspections of a representative selection of components of the different susceptible materials to determine if loss of material due to selective leaching is occurring. One-time inspections will be consistent with ASME Section XI VT-1 visual inspection requirements and supplemented by hardness tests and other examinations of the selected set of components. If selective leaching is found, the condition will be evaluated to determine the need to expand inspections. This new inspection program will be implemented prior to the period of extended operation.

A.1.25A SELECTIVE LEACHING OF MATERIALS – FRCT

The Selective Leaching of Materials - FRCT aging management program is a new program that will consist of inspections of components constructed of susceptible materials to determine if loss of material due to selective leaching is occurring. For the FRCT power plant, these are limited to copper alloy materials exposed to a closed cooling water environment. One-time inspections will consist of visual inspections supplemented by hardness tests. If selective leaching is found, the condition will be evaluated to determine the ability of the

component to perform its intended function until the end of the period of extended operation and for the need to expand inspections. This new program will be implemented in the time period after January 2018 and prior to January 2028.

A.1.26 BURIED PIPING INSPECTION

The Buried Piping Inspection aging management program is an existing program that manages the external surface aging effects of loss of material for piping and piping system components in a soil (external) environment. The Oyster Creek buried piping activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping, piping system components in the scope of license renewal that are in a soil (external) environment. The program will be enhanced to include inspection of buried piping within ten years of entering the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. The inspections will include at least one carbon steel, one aluminum and one cast iron pipe or component. In addition, for each of these materials, the locations selected for inspection will include at least one location where the pipe or component has not been previously replaced or recoated, if any such locations remain. The program will also be enhanced to include the buried portions of the fire protection system and the piping located inside the vault in the scope of the program. The vault is considered a manhole that is located between the reactor building and the exhaust tunnel.

External inspections of buried components will occur opportunistically when they are excavated during maintenance. Upon entering the period of extended operation, inspection of buried piping will be performed within ten years, unless an opportunistic inspection occurs within this ten-year period. Program enhancements will be implemented prior to entering the period of extended operation.

A.1.26A BURIED PIPING INSPECTION – FRCT

The Buried Piping Inspection - FRCT aging management program is a new program that manages the external surface aging effects of loss of material for carbon steel piping and piping system components in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping and piping system components in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of glycol cooling water piping located at the Forked River Combustion Turbine station.

External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping will again be performed

within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.

A.1.26B BURIED PIPING AND TANK INSPECTION – MET TOWER REPEATER ENGINE FUEL SUPPLY

The Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply aging management program is a new program that manages the external surface aging effects of loss of material for carbon steel and copper piping and fittings, and carbon steel tank, in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for the piping, fittings, and tank in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of the meteorological tower repeater engine fuel supply (propane) piping and tank located at the Forked River meteorological tower.

External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping components will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping components will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.

A.1.27 ASME SECTION XI, SUBSECTION IWE

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic inspection of primary containment surfaces and components, including integral attachments, and containment vacuum breakers system piping and components for loss of material, loss of sealing, and loss of preload.

Examination methods include visual and volumetric testing as required by the Code. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action process. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied to bolting.

In accordance with commitments made during the Oyster Creek license renewal application review process, the program will be enhanced to include:

1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation

and the subsequent inspection will occur two refueling outages after the initial inspection to provide early confirmation that corrosion has been arrested. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:

- Perform additional UT measurements to confirm the readings.
- Notify NRC within 48 hours of confirmation of the identified condition.
- Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected.
- Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity.
- Perform operability determination and justification for operation until next inspection.

These actions will be completed prior to restart from the associated outage.

2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:

   - 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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.

   - The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:

- Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
- UTs of the upper drywell region consistent with the existing program
- UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred
- UT results will be evaluated per the existing program
- Any degraded coating or moisture barrier will be repaired

4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.

5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.

7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.

9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from

either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).

10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

12. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected.

A.1.28 ASME SECTION XI, SUBSECTION IWF

The ASME Section XI, Subsection IWF aging management program is an existing program that consists of periodic visual examination of ASME Section XI Class 1, 2, 3 and MC components and piping support members for loss of mechanical function and loss of material. Bolting which is included with these components is monitored for loss of material and loss of preload by inspecting for missing, detached, or loosened bolts. Identification of any aging effects would initiate evaluation and establishment of corrective actions. The requirements of ASME Section XI, Subsection IWF are implemented in accordance with 10 CFR 50.55(a). The scope of the program will be enhanced to include additional MC supports, and require inspection of underwater supports for loss of material due to corrosion and loss of mechanical function and loss of preload on bolting by inspecting for missing, detached, or loosened bolts. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and torque are applied. Enhancements to the program will be implemented prior to entering the period of extended operation.

A.1.29 10 CFR PART 50, APPENDIX J

The 10 CFR Part 50, Appendix J aging management program is an existing program that monitors leakage rates through the containment pressure

boundary, including the drywell and torus, penetrations, fittings, and other access openings, in order to detect age related degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. The Appendix J program also detects age related degradation in material properties of gaskets, o-rings, and packing materials for the containment pressure boundary access points. Consistent with the current licensing basis, the containment leak rate tests are performed in accordance with the regulations and guidance provided in 10 CFR 50 Appendix J Option B, Regulatory Guide 1.163, "Performance-Based Containment Leak-Testing Program," NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J," and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

A.1.30 MASONRY WALL PROGRAM

The Masonry Wall Program is an existing program that is based on guidance provided in IE Bulletin 80-11, "Masonry Wall Design," and plant-specific monitoring proposed by IN 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," for managing cracking of masonry walls. The program requires inspection of masonry walls for cracking on a frequency of 4 years. The Masonry Wall Program is part of the Structures Monitoring Program.

A.1.31 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program is an existing program that was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2 and Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2. The program includes elements of the Masonry Wall Program and the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants aging management program.

The program relies on periodic visual inspections to monitor the condition of structures and structural components, structural bolting, component supports, masonry block walls, water-control structures, the Fire Pond Dam, exterior surfaces of mechanical components that are not covered by other programs, and HVAC ducts, damper housings, and HVAC closure bolting. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied to bolting in scope of the program.

The scope of the program will be enhanced to include structures and structural components that are not currently monitored, but determined to be in the scope of license renewal, including Station Blackout System structures and phase bus enclosure assemblies, Meteorological Tower Structures;, submerged structures, component supports not covered by other programs, the Fire Pond Dam, and exterior surfaces of Oyster Creek and Forked River Combustion Turbine mechanical components that are not covered by other programs, including exterior surfaces of HVAC ducts, damper housings, and closure bolting. The inspections will look for leakage from or onto external surfaces, worn, flaking or oxide-coated surfaces, corrosion stains on thermal insulation, and protective coating degradation (cracking and flaking). The program will also be enhanced to require removal of piping and component insulation on a sampling basis to allow visual inspection of insulated surfaces, and to require sampling and testing of groundwater every 4 years to confirm that the soil environment is non-aggressive to below-grade concrete structures. Other program scope enhancements include, but are not limited to, inspection of piping components associated with the Radio Communications system located at the meteorological tower site, and inspection of Reactor Building Closed Loop Cooling, Feedwater, and Main Steam piping located inside the Drywell. The enhancements will be made prior to entering the period of extended operation.

Inspection criteria will be enhanced to provide reasonable assurance that change in material properties, cracking, loss of material, loss of form, reduction or loss of isolation function, reduction in anchor capacity due local degradation, and loss of preload are adequately managed so that the intended functions of structures and components within the scope of the program are maintained consistent with the current licensing basis during the period of extended operation.

Inspection frequency is every four (4) years maximum; except for submerged portions of the water-control structures. A baseline inspection of submerged water-control structures will be performed prior to entering the period of extended operation. A second inspection will be performed six years after this baseline inspection and a third inspection eight years after the second inspection. After each inspection, an evaluation will be performed to determine if identified degradation warrant more frequent inspections or corrective actions.

The Structures Monitoring Program will be enhanced to include the following specific elements:

- Buildings, structural components and commodities that are not in scope of maintenance rule but have been determined to be in the scope of license renewal. These include miscellaneous platforms, flood and secondary containment doors, penetration seals, sump liners, structural seals, and anchors and embedment.

- Component supports, other than those in scope of ASME XI, Subsection IWF.

- Inspection of Oyster Creek external surfaces of mechanical components that are not covered by other programs, HVAC duct, damper housings, and HVAC closure bolting. The scope of this enhancement includes the Reactor

Building Closed Cooling Water System carbon steel piping and piping elements located inside the primary containment drywell.. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting.

- The visual inspection of insulated surfaces will require the removal of insulation. Removal of insulation will be on a sampling basis that bounds insulation material type, susceptibility of insulated piping or component material to potential degradations that could result from being in contact with insulation, and system operating temperature.

- Inspection of electrical panels and racks, junction boxes, instrument racks and panels, cable trays, offsite power structural components and their foundations, and anchorage.

- Periodic sampling, testing, and analysis of ground water to confirm that the environment remains non-aggressive for buried reinforced concrete.

- Periodic inspection of components submerged in salt water (Intake Structure and Canal, Dilution structure) and in the water of the fire pond dam, including trash racks at the Intake Structure and Canal.

- Inspection of penetration seals, structural seals, and other elastomers for change in material properties.

- Inspection of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF, for reduction or loss of isolation function.

- The current inspection criteria will be revised to add loss of material, due to corrosion for steel components, and change in material properties, due to leaching of calcium hydroxide and aggressive chemical attack for reinforced concrete. Wooden piles and sheeting will be inspected for loss of material and change in material properties.

- Periodic inspection of the Fire Pond Dam for loss of material and loss of form.

- Inspection of Station Blackout System structures, structural components, and phase bus enclosure assemblies.

- Inspection of Forked River Combustion Turbine power plant external surfaces of mechanical components that are not covered by other programs, HVAC duct, damper housings, and HVAC closure bolting. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting.

- The program will be enhanced to include inspection of Meteorological Tower Structures. Inspection and acceptance criteria will be the same as those specified for other structures in the scope of the program.

- The program will be enhanced to include inspection of exterior surfaces of piping and piping components associated with the Radio Communications

system, located at the meteorological tower site, for loss of material due to corrosion. Inspection and acceptance criteria will be the same as those specified for other external surfaces of mechanical components.

- The program will be enhanced to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs for leakage from or onto external surfaces, worn, flaking, or oxide-coated surfaces, corrosion stains on thermal insulation, and protective coating degradation (cracking and flaking).

- To confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the main steam system located inside containment, a one-time visual inspection for loss of material due to corrosion will be performed.

- To confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the feedwater system located inside primary containment drywell, a one-time visual inspection for loss of material due to corrosion will be performed.

A.1.32 RG 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

The Oyster Creek RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," aging management program is an existing condition monitoring program that is a part of the Structures Monitoring Program. The program requires periodic inspection of the Intake Structure and Canal (UHS), and the Dilution structure concrete for loss of material, cracking, and changes in material properties. Steel components are inspected for loss of material due to corrosion, and the earthen dike and canal slopes are monitored for loss of material and loss of form. The program will be enhanced to include periodic inspection of the Fire Pond Dam for loss of material and loss of form. Other enhancements include periodic inspection of submerged concrete, wood, and steel components for age related degradations. Inspection frequency is every four (4) years; except for submerged portions of the structures, which will be inspected (baseline) prior to entering the period of extended operation. A second inspection will be performed 6 years after this baseline inspection and a third 8 years after the second. After each inspection an evaluation will be performed to determine if the identified degradations warrant more frequent inspections or corrective actions to ensure that age-related degradation is properly managed.

A.1.33 PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

The Protective Coating Monitoring and Maintenance Program is an existing program that provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region. Service Level I coatings are used in areas where corrosion protection may be required and where coating failure could adversely affect the operation of post-accident fluid systems and thereby

impair safe shutdown. Oyster Creek was not originally committed to Regulatory Guide 1.54 for Service Level I coatings because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Service Level II coatings provide corrosion protection and decontaminability in those areas outside of the primary containment that are subject to radiation exposure and radionuclide contamination. The Protective Coating Monitoring and Maintenance Program provides for inspections, assessment, and repairs for any condition that adversely affects the ability of Service Level I coatings, or sandbed region Service Level II coatings, to function as intended.

The program will be enhanced to include:

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

2. Additional visual inspections of the epoxy coating that was applied to the exterior surface of the drywell shell in the sand bed region, such that the coated surfaces in all 10 drywell bays will have been inspected at least once prior to entering the period of extended operation.

3. The inspection of 100% of the sandbed region epoxy coating every 10 years during the period of extended operation. Inspections will be staggered such that at least three bays will be examined every other refueling outage.

4. The inspection of all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the current coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.

Enhancements will be implemented prior to the period of extended operation and every ten years during the period of extended operation.

A.1.34 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage aging of non-EQ cables and connections during the period of extended operation. A representative sample of accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of accelerated insulation aging such as embrittlement, discoloration, cracking, or surface contamination. An adverse localized environment is a condition in a limited plant area that is

significantly more severe than the specified service environment for a subject electrical cable or connection. This new program will be implemented prior to the period of extended operation.

A.1.35 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENT CIRCUITS

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits aging management program is an existing program that manages aging of the cables of the Intermediate Range Monitoring (IRM), Local Power Range Monitoring/Average Power Range Monitoring (LPRM/APRM), Reactor Building High Radiation Monitoring, and Air Ejector Offgas Radiation Monitoring systems that are sensitive instrumentation circuits with low-level signals and are located in areas where the cables and connections could be exposed to adverse localized environments caused by heat, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance causing increases in leakage currents. Calibration testing and Current/Voltage (I/V) and Time Domain Reflectometry (TDR) testing are currently performed to ensure that the cable insulation resistance is adequate for the instrumentation circuits to perform their intended functions. Based on acceptance criteria related to instrumentation loop performance and cable testing set forth in the calibration and testing procedures, evaluation of unacceptable results is initiated under the Corrective Action Process. The calibration testing and cable testing used for this program are performed currently, and have proven effective in identifying the existence of degradation in the performance of the tested systems. The program will be enhanced to include a review of the calibration and cable testing results for cable aging degradation as recommended by NUREG 1801 Section XI.E2. The enhanced program will be implemented prior to the period of extended operation and will include a review of the calibration and cable testing results for cable aging degradation before the period of extended operation and every 10 years thereafter.

A.1.36 INACCESSIBLE MEDIUM-VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage the aging of medium-voltage (2.3 kV, 4.1 kV, 13.8 kV and 34.5 kV) cable circuits at Oyster Creek. These cables may at times be exposed to moisture and may be subjected to system voltage for more than 25% of the time. Manholes, conduits and sumps associated with these cable circuits will be inspected for water collection at least once every 2 years and drained as required. The first inspections will be completed prior to the period of extended operation. In addition, the cable circuits will be tested using a proven test for detecting deterioration of the insulation system due to wetting, such as power factor or partial discharge, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. The

cable circuits will be tested at an initial frequency of six years, after which the frequency will be evaluated and adjusted, based on test results; period between tests shall not exceed 10 years. Results of cable tests will be trended. Trending will occur at the same frequency as cable testing. This new program will be implemented prior to the period of extended operation. Inclusion of the 13.8 kV system circuits in this program reflects the scope expansion of the Station Blackout System electrical commodities. Inclusion of the 34.5 kV system circuits in this program reflects the scope enhancement for reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.

A.1.37 PERIODIC MONITORING OF COMBUSTION TURBINE POWER PLANT – ELECTRICAL

The new Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program will be used in conjunction with the existing Structures Monitoring Program, the new Inaccessible Medium Voltage Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements program and the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program to manage aging effects for the electrical commodities that support Forked River Combustion Turbine (FRCT) operation. The Program consists of visual inspection of accessible electrical cables and connections exposed in enclosures, pits, manholes, and pipe trench for embrittlement, discoloration, cracking or surface contamination; visual inspection of manholes, pits and cable trenches, located on the FRCT site, for inaccessible medium voltage cables, for water collection; visual inspections of accessible phase bus and connections and phase bus insulators for melting or other signs of heat effects on the tape covering bus connections, cracking of thermoplastic, or degradation of insulators; and visual inspection of high voltage insulators above 34.5 kV for salt build-up. Phase Bus Enclosures will be inspected by the existing Structures Monitoring Program for signs of corrosion. The inaccessible medium voltage cables circuits supporting the FRCT, and the associated manholes, pits and trenches located on the Oyster Creek site, will be tested or inspected by the new Inaccessible Medium Voltage Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements program for signs of insulation degradation and for prevention of wetted environments. Electrical cable connections, metallic parts, located at the Forked River Combustion Turbine power plant will be included in the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program which will test a representative sample of connections for loosening. The new combustion turbine power plant – electrical program will be implemented prior to the period of extended operation. Manhole, pit and trench inspections for manholes, pits and trenches located on the FRCT site will be performed at least once every 2 years for accumulation of water, and the frequency will be adjusted based on the results obtained. Cable and connection inspections will be implemented prior to the period of extended operation with a frequency of at least once every 10 years. Accessible phase bus and connection and phase bus insulator inspections will be performed at least once every 5 years. Visual inspections of high voltage insulators will be performed at least twice per year. Phase bus enclosure inspections will be performed at the frequency specified in the

Structures Monitoring Program. Inaccessible medium voltage cable circuits and the associated manhole, pit and trench tests and inspections for the manholes, pits and trenches located on the OC site will be performed at the frequency specified in the Inaccessible Medium Voltage Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements program. Electrical cable connections will be tested at the frequency specified in the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.

A.1.38 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS – FRCT

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT aging management program is a new program that consists of visual inspections of the internal surfaces of steel piping, valve bodies, ductwork, filter housings, fan housings, damper housings, mufflers and heat exchanger shells in the scope of license renewal at the Forked River Combustion Turbine power plant that are not covered by other aging management programs. These components are subject to an internal environment of indoor air that is assumed to include sufficient moisture content to result in loss of material aging effects. In addition, this program includes piping and mufflers with Diesel Engine Exhaust Gas as an internal environment. Internal inspections will be performed during scheduled maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. These inspections will be performed during the major combustion turbine inspection outages and will be performed on a frequency of at least once every 10 years.

The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.

A.1.39 LUBRICATING OIL ANALYSIS PROGRAM - FRCT

The Lubricating Oil Analysis Program – FRCT is a new program that includes measures to verify the oil environment in mechanical equipment is maintained to the required quality. The Lubricating Oil Analysis Program – FRCT maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction in heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup. The program will also include the measurement of flash point. This program is augmented by the One Time Inspection – FRCT (B.1.24A) program, to verify the effectiveness of the Lubricating Oil Analysis Program - FRCT. This new program will be implemented prior to the period of extended operation.

A.1.40 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage the aging effects of metallic parts of non-EQ electrical cable connections within the scope of license renewal during the period of extended operation. A representative sample of non-EQ electrical cable connections will be selected for testing considering application (high, medium and low voltage), circuit loading and location, with respect to connection stressors. The type of test to be performed, i.e., thermography, is a proven test for detecting loose connections. A representative sample of non-EQ cable connections will be tested at least once every 10 years. This new program will be implemented prior to the period of extended operation.

A.2 PLANT SPECIFIC PROGRAMS

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

A.2.1 PERIODIC TESTING OF CONTAINMENT SPRAY NOZZLES

The Periodic Testing of Containment Spray Nozzles aging management program is an existing program that provides for flow tests to demonstrate that the drywell and torus spray nozzles are not blocked by debris or corrosion products. Carbon steel piping upstream of the drywell and torus spray nozzles is subject to possible general corrosion. The periodic flow tests of drywell and torus spray nozzles address a concern that rust from the possible general corrosion may plug the spray nozzles. These periodic tests verify that the drywell and torus spray nozzles are free from plugging that could result from corrosion product buildup from upstream sources.

A.2.2 LUBRICATING OIL MONITORING ACTIVITIES

The Lubricating Oil Monitoring Activities aging management program is an existing program that manages loss of material, cracking, and fouling in lubricating oil heat exchangers, systems, and components in the scope of license renewal by monitoring physical and chemical properties in lubricating oil. Sampling, testing, and monitoring verify lubricating oil properties. Oil analysis permits identification of specific wear mechanisms, contamination, and oil degradation within operating machinery, and components of systems in scope for license renewal.

The Lubricating Oil Monitoring Activities program will be enhanced to add surveillance for verification of flow through the Fire Protection System diesel driven pump gearbox lubricating oil cooler. In addition, the program will be enhanced to include sampling and measurement for flash point of emergency diesel generator engine lubricating oil to detect contamination of lube oil by fuel

oil. These enhancements will be implemented prior to the period of extended operation.

A.2.3 GENERATOR STATOR WATER CHEMISTRY ACTIVITIES

The Generator Stator Water Chemistry Activities aging management program is an existing program that manages loss of material aging effects by monitoring and controlling water chemistry. Generator stator water chemistry control maintains high purity water in accordance with General Electric and EPRI guidelines for stator cooling water systems. Generator stator water is continuously monitored for conductivity and periodically analyzed for impurities and dissolved oxygen, and an alarm annunciates if conductivity increases to a predetermined limit.

A.2.4 PERIODIC INSPECTION OF VENTILATION SYSTEMS

The Periodic Inspection of Ventilation Systems aging management program is an existing program that provides for periodic inspections of components in the ventilation systems in the scope of license renewal at Oyster Creek. The program includes inspections for penetrating corrosion on ventilation system components and evidence of aging and wear on elastomers for the portions of the systems that are within the scope of license renewal. Prior to the period of extended operation, the program will be enhanced to include duct exposed to soil, instrument piping and valves, restricting orifices and flow elements, and thermowells. The activities will also be enhanced to include inspection guidance for detection of the applicable aging effects.

A.2.5 PERIODIC INSPECTION PROGRAM

The Periodic Inspection Program is a new program that will consist of periodic inspections of selected systems to verify the integrity of the system and confirm the absence of identified aging effects. The initial inspections are scheduled for implementation prior to the period of extended operation. The purpose of the inspection is to determine if a specified aging effect is occurring. If the aging effect is occurring, an evaluation will be performed to determine the effect it will have on the ability of affected components to perform their intended functions for the period of extended operation, and appropriate corrective action is taken.

Inspection methods may include visual examination, surface or volumetric examinations. Acceptance criteria are in accordance with industry guidelines, codes, and standards. When inspection results fail to meet established acceptance criteria, an evaluation will be conducted, in accordance with the corrective action process, to establish additional actions or measures necessary to provide reasonable assurance that the component intended function is maintained during the period of extended operation. This new program will be implemented prior to the period of extended operation.

A.2.5A PERIODIC INSPECTION PROGRAM – FRCT

The Periodic Inspection Program - FRCT is a new program that will consist of periodic inspections of selected components to verify the integrity of the system and confirm the absence of identified aging effects. Inspections will be scheduled to coincide with major combustion turbine maintenance inspections, when the subject components are made accessible. These inspections will be performed on a frequency not to exceed once every 10 years. The purpose of the inspection is to determine if a specified aging effect is occurring. If the aging effect is occurring, an evaluation will be performed to determine the effect it will have on the ability of affected components to perform their intended functions for the period of extended operation, and appropriate corrective action is taken.

Inspection methods may include visual examination, surface or volumetric examinations. Acceptance criteria are in accordance with manufacturers guidelines, applicable codes, and standards. When inspection results fail to meet established acceptance criteria, an evaluation will be conducted to identify actions or measures necessary to provide reasonable assurance that the component intended function is maintained during the period of extended operation.

The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.

A.2.6 WOODEN UTILITY POLE PROGRAM

The Oyster Creek Wooden Utility Pole Program is a new program that will be used to manage loss of material and change of material properties for wooden utility poles in or near the Oyster Creek Substation that provide structural support for the conductors connecting the Offsite Power System and the 480/208/120V Utility (JCP&L) Non-Vital Power System to the Oyster Creek plant. The program consists of inspection on a 10-year interval by a qualified inspector. The wooden poles will be inspected for loss of material due to ant, insect, and moisture damage and for change in material properties due to moisture damage. This new program will be implemented prior to the period of extended operation.

A.3 TLAA EVALUATION OF AGING MANAGEMENT PROGRAMS UNDER 10 CFR54.21(C)(1)(III)

This section provides summaries of programs credited in the evaluation of Time-Limited Aging Analyses (TLAAs).

A.3.1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

The Metal Fatigue of Reactor Coolant Pressure Boundary aging management program is an existing program that ensures that the design fatigue usage factor limit will not be exceeded during the period of extended operation. The program

will be enhanced to calculate and track cumulative usage factors for bounding locations in the reactor coolant pressure boundary (reactor pressure vessel and Class I piping), containment torus, torus vents, and torus attached piping and penetrations. The program also tracks isolation condenser fatigue stress cycles. The program will be enhanced to use the EPRI-licensed FatiguePro® cycle counting and fatigue usage factor tracking computer program, which provides for calculation of stress cycles and fatigue usage factors from operating cycles, automated counting of fatigue stress cycles, and automated calculation and tracking of fatigue cumulative usage factors. FatiguePro calculates cumulative fatigue using both cycle-based and stress-based monitoring. The program will be enhanced prior to the period of extended operation.

Prior to the period of extended operation, AmerGen will revise the Oyster Creek UFSAR to update the current licensing basis to reflect that a cumulative usage factor of 1.0 will be used in fatigue analysis for reactor coolant pressure boundary components, as endorsed by the NRC in 10 CFR 50.55a.

A.3.2 ENVIRONMENTAL QUALIFICATION (EQ) PROGRAM

The Environmental Qualification (EQ) Program is an existing program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." The program establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance and replacements necessary to meet 10 CFR 50.49. A qualified life is determined for equipment within the scope of the program and appropriate actions such as replacement or refurbishment are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The effects of aging on the intended functions will be adequately managed per the requirements of 10 CFR 54.21 (c)(1)(iii).

A.4 TIME-LIMITED AGING ANALYSIS SUMMARIES

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the period of extended operation be provided. The following TLAAs have been identified and evaluated to meet this requirement.

A.4.1 NEUTRON EMBRITTLEMENT OF THE REACTOR VESSEL AND INTERNALS

The ferritic materials of the reactor vessel are subject to embrittlement due to high energy neutron exposure. Reactor vessel neutron embrittlement is a TLAA.

A.4.1.1 Reactor Vessel Materials Upper-Shelf Energy Reduction Due to Neutron Embrittlement

The reactor vessel end-of-life neutron fluence has been recalculated for a 60-year (50 EFPY) extended licensed operating period using the RAMA methodology. The NRC has issued a SER for RAMA approving RAMA for reactor vessel fluence calculations. Oyster Creek will comply with the applicable requirements of the SER before the period of extended operation.

The 50 EFPY USE was evaluated by an equivalent margin analysis (EMA) using the 50 EFPY calculated fluence and the Oyster Creek surveillance capsule results, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

A.4.1.2 Adjusted Reference Temperature for Reactor Vessel Materials Due to Neutron Embrittlement

The reactor vessel materials peak fluence, ΔRT_{NDT}, and ART values for the 60-year (50 EFPY) license operating period were calculated in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

A.4.1.3 Reactor Vessel Thermal Limit Analyses: Operating Pressure – Temperature Limits

Revised pressure-temperature (P-T) limits for a 60-year licensed operating life have been prepared and will be submitted to the NRC for approval prior to the start of the extended period of operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

A.4.1.4 Reactor Vessel Circumferential Weld Examination Relief

Relief has been granted from the requirements for inspection of RPV circumferential welds for the remainder of the current 40-year licensed operating period. The justification for relief is consistent with the guidelines of Boiling Water Reactor Vessel and Internals Program BWRVIP-05, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations." Application for an

extension of this relief for the 60-year period of extended operation will be submitted prior to the end of the current operating license term.

The re-evaluation of the circumferential weld failure probability for 60 years depends on vessel ΔRT_{NDT} calculations. Although a conditional failure probability has not been calculated, the fact that the Oyster Creek 50 EFPY Mean RT_{NDT} value is less than the 64 EFPY value provided by the NRC leads to the conclusion that the Oyster Creek RPV conditional failure probability is bounded by the NRC analysis and is therefore acceptable. The procedures and training that will be used to limit the frequency of cold over-pressure events to the number specified in the SER for the RPV circumferential weld relief request extension, during the license renewal term, are the same as those approved for use in the current period end of the current operating license term.

The above analyses associated with reactor vessel circumferential weld examination relief has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

A.4.1.5 Reactor Vessel Axial Weld Examination Relief

BWRVIP-05, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," estimated the 40-year end-of-life failure probability of a limiting reactor vessel axial weld, showed that it was orders of magnitude greater than the 40-year end-of-life circumferential weld failure probability, and used this analysis to justify relief form inspection of the circumferential welds, as described in Section a.4.1.4 above.

The re-evaluation of the axial weld failure probability for 60 years depends on vessel ΔRT_{NDT} calculations. The NRC staff review and BWRVIP calculations of the test-case failure probabilities assume that 90 percent of axial welds will be inspected. At Oyster Creek, less than 90 percent of axial welds can be inspected. As such, an analysis was performed for 50 EFPY to assess the effect on the probability of fracture due to the actual inspection performed on the vessel axial welds and to determine if the coverage was sufficient in the inspection of regions contributing to the majority of the risk.

The evaluation shows that the calculated unit-specific axial weld conditional failure probabilities at 60 years (50 EFPY) for Oyster Creek are less than the failure probabilities calculated by the NRC staff in the NRC BWRVIP-05 SER at 64 EFPY and the limiting CEOG values found in Table 3 of the SER supplement. The projected probability of failure of an axial weld at Oyster Creek will therefore provide adequate margin above the probability of failure of a circumferential weld, in support of relief from inspection of circumferential welds, for the extended licensed operating period, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

A.4.1.6 Reactor Internals Components

The core plate, core shroud, incore instrumentation dry tubes, and top guide are exposed to high neutron fluence and are potentially susceptible to stress relaxation of bolting and irradiation assisted stress corrosion cracking (IASCC).

Because the core plate has wedges installed, relaxation of the hold bolts due to is not a concern. The top guide, core shroud, and incore dry tubes are considered susceptible to IASCC and require aging management. All three components (top guide, core shroud, and incore dry tubes) have been evaluated by the BWRVIP, as described in the Inspection and Evaluation Guidelines for each component. The BWR Vessel Internals program described in Section A.1.9 will manage these aging effects.

This aging management program will ensure that aging effects in vessel internals exposed high fluence will be adequately managed for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

A.4.2 METAL FATIGUE

The thermal and mechanical fatigue analyses of mechanical components have been identified as TLAAs for Oyster Creek. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the Oyster Creek UFSAR.

A.4.2.1 Reactor Vessel Fatigue Analyses

Reactor vessel fatigue analyses depend on cycle count assumptions that assume a 40-year operating period. The effects of fatigue in the reactor vessel will be managed for the period of extended operation by the Metal Fatigue of Reactor Coolant Pressure Boundary aging management program for cycle counting and fatigue usage factor tracking, as described in Section A.3.1.

This aging management program will ensure that fatigue effects in vessel pressure boundary components will be adequately managed and will be maintained within the design limits for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

A.4.2.2 Fatigue Analysis of Reactor Vessel Internals

A.4.2.2.1 Low-cycle Thermal and Flow-Induced Vibration Fatigue Analysis of the Core Shroud and Repair Hardware

Low-cycle mechanical fatigue was evaluated only for the tie rod stabilizers in the core shroud repair evaluations. The maximum predicted CUF for the core shroud and core shroud repair hardware was found to be not significant. Therefore, the design of the core shroud repair hardware for fatigue effects is valid for the extended operating period in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.3 Reactor Coolant Pressure Boundary Piping and Component Fatigue Analysis

A.4.2.3.1 Reactor Coolant Pressure Boundary Piping and Components

Thermal cycle count is a consideration in all the codes associated with the design of reactor coolant pressure boundary and non-RCPB piping and components (e.g., USAS or ANSI B31.1).

The applicable piping codes require the use of a stress range reduction factor in the evaluation of calculated stresses due to thermal expansion. The reduction factor is based on the anticipated number of equivalent full temperature cycles over the total number of years the plant is expected to be in operation.

The number of thermal cycles assumed for design of RCPB and non-RCPB piping has been evaluated and the existing stress range reduction factor remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.3.3 Fatigue Analysis of the Isolation Condenser

The isolation condenser components were evaluated for 1500 heatup/pressurization cycles for 40 years. A review of isolation condenser operations since 1995 and a conservative estimate of earlier condenser operations based on number of unit scrams concluded that the projected total cycle count for 60 years is well below the number of design cycles.

The isolation condenser supporting system piping and components were evaluated for 400 heatup/pressurization cycles for 40 years. The "A" isolation condenser tubes bundles were replaced in 2000 and the "B" isolation condenser tube bundles were replaced in 1998. The isolation condenser piping was replaced in 1992. Conservatively using 1992 as the starting point for isolation condenser events for these components, a review of isolation condenser events since 1992 concluded that the projected total cycle count for 60 years is well below the number of design cycles.

The analyses of the effects of thermal cycle and thermal shock events on the Oyster Creek isolation condenser systems and components have been evaluated and remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

A.4.2.4 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)

Generic Safety Issue (GSI) 190 was identified by the NRC because of concerns about potential effects of reactor water environments on component fatigue life during the period of extended operation.

Oyster Creek has performed plant-specific calculations for the applicable locations identified in NUREG/CR 6260, "Application of NUREG/CR-5999 Interim

Fatigue Curves to Selected Nuclear Power Plant Components," for older-vintage BWR plants. For each location, detailed environmental fatigue calculations were performed using the appropriate environmental fatigue (F_{en}) relationships from NUREG/CR 6583 for carbon and low-alloy steels and from NUREG/CR 5704 for stainless steels, as appropriate for the material at each of the locations. The results demonstrate that all CUF values, including appropriate environmental effects, are less than 1.0 for 60 years of plant operation and meet the requirements for the extended operating period in accordance with 10 CFR 54.21(c)(1)(ii).

Additionally, all of the above locations are included in the Metal Fatigue of Reactor Coolant Pressure Boundary (A.3.1) aging management program, and the CUF for these locations will continue to be tracked in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

A.4.3 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT (EQ)

Electrical equipment included in the Oyster Creek Environmental Qualification Program, which has a specified qualified life of at least 40 years, involves time-limiting aging analyses for license renewal. The aging effects of this equipment will be managed in the Environmental Qualification Program discussed in Section A.3.2, "Environmental Qualification (EQ) of Electrical Components," in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

A.4.4 FATIGUE OF PRIMARY CONTAINMENT, ATTACHED PIPING AND COMPONENTS

The Oyster Creek Mark I containment was originally designed to stress limit criteria without fatigue analyses. However, the discovery of significant hydrodynamic loads ("new loads") caused by safety relief valve (SRV) and small, intermediate, and design basis pipe break discharges into the suppression pool required the reanalysis of the suppression chamber, vents, and attached piping and internal structures, including some fatigue analyses at limiting locations. These fatigue analyses of the suppression chamber, and its internals, and vents in each unit included assumed pressure and temperature cycles resulting from SRV discharge and design basis LOCA events. The scope of the analyses included pressure suppression chamber, the drywell-to-pressure suppression chamber vents, SRV discharge piping, other piping attached to the suppression chamber and its penetrations, and the drywell-to-suppression chamber vent bellows.

A.4.4.1 Fatigue Analysis of the Primary Containment System (Includes Suppression Chamber, Vents, Vent Headers, and Downcomers, SRV Discharge Piping Inside the Suppression Chamber, External Suppression Chamber Attached Piping, Associated Penetrations, Drywell-to-Suppression Chamber Vent Line Bellows, and Primary Containment Process Penetrations Bellows)

For low cumulative usage factor (CUF) locations (40-year CUF < 0.4) the Oyster Creek new loads analyses of each suppression chamber and its associated vents and downcomers, piping penetrations and vent bellows have been evaluated and remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

For higher cumulative usage factor locations in the analyses of the suppression chamber and its associated vents and downcomers, piping penetrations and vent bellows (40-year CUF ≥ 0.4) the effects of fatigue will be managed for the period of extended operation by the Metal Fatigue of Reactor Coolant Pressure Boundary aging management program, as described in Section A.3.1.

The fatigue management activities will ensure that fatigue effects in containment pressure boundary components are adequately managed and are maintained within code design limits for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

A.4.4.2 Primary Containment Process Penetrations and Bellows Fatigue Analysis

The only containment process piping expansion joints subject to significant thermal expansion and contraction are those between the drywell shell penetrations and process piping. These are designed for a stated number of operating and thermal cycles.

The thermal cycle designs of Oyster Creek containment process penetration bellows have been evaluated and remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A.4.5 OTHER PLANT-SPECIFIC TLAAS

A.4.5.1 Reactor Building, Turbine Building, and Heater Bay Crane Load Cycles

The reactor building, turbine building and heater bay cranes at Oyster Creek were designed to meet or exceed the design criteria of the Crane Manufacturers Association of America (CMAA) Specification 70, "Specifications for Electric Overhead Traveling Cranes," Class A1. These cranes are capable of a minimum of 20,000 cycles at rated capacity.

The load cycle design of these Oyster Creek cranes have been evaluated and remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A.4.5.2 Drywell Corrosion

Analysis of the minimum wall thickness of the containment vessel is a TLAA. The aging effects will be managed by the ASME Section XI, Subsection IWE aging management program, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii), augmented by activities described in UFSAR Section A.1.27.

A.4.5.3 Equipment Pool and Reactor Cavity Walls Rebar Corrosion

Corrosion of reinforcing bar in localized areas of the reactor cavity and equipment pool walls was suspected as a result of observed rust in and around cracks in the walls between elevation 95' and 119'. To assess the condition of the reinforcing bars, concrete core samples were taken in 1988 and chemically analyzed to determine if water intrusion into concrete cracks created an environment that is aggressive to rebar. These analyses showed that the environment is not aggressive and thus corrosion should not be significant.

However because of the observed rust like substance in and around the cracks, the affected rebar were conservatively assumed to be subject to corrosion of 0.020 inches all around the rebar during the current term. Engineering analysis concluded the corrosion amount of reinforcing bars would not impact structural integrity of the affected walls during the current period of operation.

For the period of extended operation, corrosion of the reinforcing bars and the rate at corrosion is a TLAA. Although there is no evidence of continuing rebar corrosion, AmerGen is conservatively assuming additional corrosion of 0.010 inches all around the rebar during the period of extended operation. Corrosion of the reinforcing bar has been projected to the end of the extended period in accordance with 10 CFR 54.21(c)(1)(ii), and determined that the intended function of the drywell shield wall and the equipment pool wall will be maintained through the period of extended operation.

A.4.5.4 Reactor Vessel Weld Flaw Evaluations

Flaws evaluated in 2000 as part of the 2000 ISI inspections were based on conditions valid for the current life of the plant, including fluence at 32 EFPY, thermal transients, and existing P-T curves. These flaws were evaluated in accordance with ASME Section XI, IWB-3600 for the period of extended operation. These flaws have been reevaluated for 50 EFPY conditions in accordance with 10 CFR 54.21(c)(1)(ii) and found to be acceptable for the period of extended operation.

A.4.5.5 CRD Stub Flaw Evaluation

As part of the weld repair project for the CRD stubs during the construction phase of the plant, an evaluation of a postulated residual flaw was performed. The analysis of the postulated undetected flaw states that it would require more than 1000 startup and shutdown cycles to propagate the flaw to the surface, potentially leading to coolant leakage. The projected number of startup and shutdown cycles at the end of the period of extended operation is less than 275. Therefore the flaw evaluation is valid for the period of extended operation.

This flaw evaluation have been reevaluated for 60 years of operation in accordance with 10 CFR 54.21(c)(1)(ii) and found to be acceptable for the period of extended operation.

A.5 License Renewal Commitment List

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing program is credited. For the isolation condensers this program also includes enhancement activities identified in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," lines IV.C1-5 and IV.C1-6. These enhancement activities consist of: 1. Temperature and radioactivity monitoring of the shell-side (cooling) water, which will be implemented prior to the period of extended operation. 2. Eddy current testing of the tubes, with inspection (VT or UT) of the tubesheet and channel head, which will be performed during the first ten years of the extended period of operation.	A.1.1	Prior to the period of extended operation	Section B.1.1
2) Water Chemistry	Existing program is credited.	A.1.2	Ongoing	Section B.1.2
3) Reactor Head Closure Studs	Existing program is credited.	A.1.3	Ongoing	Section B.1.3
4) BWR Vessel ID Attachment Welds	Existing program is credited.	A.1.4	Ongoing	Section B.1.4
5) BWR Feedwater Nozzle	Existing program is credited. The Oyster Creek Feedwater Nozzle aging management program will be enhanced to implement the recommendations of the BWR Owners Group Licensing Topical Report General Electric (GE) NE-523-A71-0594-A, Revision 1.	A.1.5	Prior to the period of extended operation	Section B.1.5
6) BWR Control Rod Drive Return Line Nozzle	Existing program is credited.	A.1.6	Ongoing	Section B.1.6

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
7) BWR Stress Corrosion Cracking	Existing program is credited. The program will be enhanced to add the following requirement to the Line Specifications for all applicable license renewal systems: "All new and replacement SS materials be low-carbon grades of SS with carbon content limited to 0.035 wt. % maximum and ferrite content limited to 7.5% minimum."	A.1.7	Prior to the period of extended operation	Section B.1.7
8) BWR Penetrations	Existing program is credited.	A.1.8	Ongoing	Section B.1.8
9) BWR Vessel Internals	Existing program is credited. The program will be enhanced to include: 1. Inspection of the steam dryer in accordance with BWRVIP-139. 2. Inspection of the top guide as recommended in NUREG-1801. 3. Rolling of the CRD stub tubes as a permanent repair, once the NRC approves the ASME code case (Code Case N-730). If Code Case N-730 is not approved, Oyster Creek will develop a permanent ASME code repair plan. This permanent ASME code repair could be performed in accordance with BWRVIP-58-A, which has been approved by the NRC, or an alternate ASME code repair plan that would be submitted for prior NRC approval. If it is determined that the repair plan needs prior NRC approval, Oyster Creek will submit the repair plan two years before entering the period of extended operation. After the implementation of	A.1.9	Prior to the period of extended operation	Section B.1.9

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	an approved permanent roll repair, if there is a leak in a CRD stub tube, Oyster Creek will weld repair any leaking CRD stub tubes during the extended period of operation by implementing a permanent NRC approved ASME Code repair for leaking stub tubes that cannot be made leak tight using a roll expansion method, prior to restarting the plant. 4. Oyster Creek will revise its Reactor internals program to also manage the aging effect of loss of material due to the aging mechanisms of pitting and crevice corrosion for Reactor Internals. 5. Oyster Creek will comply with all the applicable requirements that will be specified in the staff's final safety evaluations (SEs) of the BWRVIP-76 and BWRVIP-104 reports, and that it will complete all the license renewal action items in the final SE applicable to Oyster Creek, when they are issued. 6. The Reactor Internals program will be enhanced to include inspection for loss of material for the feedwater sparger, steam separator, RPV surveillance capsule holders and baffle plate. 7. The Reactor Internals Program will be enhanced to include and document the condition of the CRD and Feedwater Nozzle thermal sleeves to ensure future inspections look for thermal sleeve bypass flow. 8. AmerGen/Exelon is committed to following BWRVIP guidelines • Oyster Creek will inform the (NRC) staff of any			

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	decision to not fully implement a BWRVIP guidelines approved by the staff within 45 days of the report • Oyster Creek will notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP report. • Oyster Creek will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP report.			
10) Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Program is new. The program will include a component specific evaluation of the loss of fracture toughness in accordance with the criteria specified in NUREG-1801, XI.M13. For those components where loss of fracture toughness may affect the intended function of the component, a supplemental inspection will be performed. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.	A.1.10	Prior to the period of extended operation	Section B.1.10
11) Flow-Accelerated Corrosion	Existing program is credited.	A.1.11	Ongoing	Section B.1.11
12) Bolting Integrity	Existing program is credited. Program site implementing documents will be enhanced to include reference to EPRI TR-104213, Bolted Joint Maintenance & Application Guide, December 1995.	A.1.12	Prior to the period of extended operation	Section B.1.12

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
13) Open-Cycle Cooling Water System	Existing program is credited. The program will be enhanced as follows. Volumetric inspections, for piping that has been replaced, will be included at a minimum of 4 aboveground locations every 4 years. Inspection of heat exchangers will specify examination for loss of material due to general, pitting, crevice, galvanic and microbiologically influenced corrosion in the RBCCW, TBCCW and Containment Spray preventative maintenance tasks.	A.1.13	Prior to the period of extended operation	Section B.1.13
14) Closed-Cycle Cooling Water System	Existing program is credited.	A.1.14	Ongoing	Section B.1.14
15) Boraflex Monitoring	Existing program is credited.	A.1.15	Ongoing	Section B.1.15
16) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Existing program is credited. The scope of the program will be increased to include additional hoists that have been identified as a potential Seismic II/I concern and are in scope for 10CFR54.4(a)(2). The program will also be enhanced to include inspections for rail wear, and loss of material due to corrosion, of cranes and hoists structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system.	A.1.16	Prior to the period of extended operation	Section B.1.16
17) Compressed Air Monitoring	Existing program is credited.	A.1.17	Ongoing	Section B.1.17
18) BWR Reactor Water Cleanup System	Existing program is credited. Based on Generic Letter 89-10 containment isolation valve upgrades/enhancements, an effective Hydrogen Water	A.1.18	Ongoing	Section B.1.18

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	Chemistry program, and the complete lack of cracking found during any of the RWCU piping weld inspections performed under Generic Letter 88-01, all inspection requirements for the portion of the RWCU System outboard of the second containment isolation valves have been eliminated.			
19) Fire Protection	Existing program is credited. The program will be enhanced to include: 1. Specific fuel supply inspection criteria for fire pumps during tests. 2. Inspection of external surfaces of the halon and carbon dioxide fire suppression systems. 3. Additional inspection criteria for degradation of fire barrier walls, ceilings, and floors. 4. Clearance inspection of in-scope fire doors every two years.	A.1.19	Prior to the period of extended operation	Section B.1.19
20) Fire Water System	Existing program is credited. The program will be enhanced to include: 1. Sprinkler head testing in accordance with NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." Samples will be submitted to a testing laboratory prior to being in service 50 years. This testing will be repeated at intervals not exceeding 10 years. 2. Water sampling for the presence of MIC at an interval not to exceed 5 years. 3. Periodic non-intrusive wall thickness measurements of selected portions of the fire water	A.1.20	Prior to the period of extended operation	Section B.1.20

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	system at an interval not to exceed every 10 years. 4. Visual inspection of the redundant fire water storage tank heater during tank internal inspections.			
21) Aboveground Outdoor Tanks	Program is new. The program will manage the corrosion of outdoor carbon steel and aluminum tanks. The program credits the application of paint, sealant, and coatings as a corrosion preventive measure and performs periodic visual inspections to monitor degradation of the paint, sealant, and coatings and any resulting metal degradation of carbon steel or of the unpainted aluminum tank. Bottom UTs are performed on tank bottoms supported by soil or concrete.	A.1.21	Prior to the period of extended operation	Section B.1.21
22) Fuel Oil Chemistry	Existing program is credited. The program will be enhanced to include: 1. Routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on fuel oil samples from the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank. 2. Analysis for particulate contamination using modified ASTM D 2276-00 Method A on new fuel oil. 3. Analysis for water and sediment using ASTM D 2709-96 for Fire Pond Diesel Fuel Tank bottom samples.	A.1.22	Prior to the period of extended operation	Section B.1.22

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	4. Analysis for bacteria to verify the effectiveness of biocide addition in the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank. 5. Periodic draining, cleaning, and inspection of the Fire Pond Diesel Fuel Tanks and the Main Fuel Oil Tank. Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of corrosion or pitting. 6. One time internal inspection of the Emergency Diesel Generator fuel oil day tanks prior to the period of extended operation to confirm the absence of aging effects.			
23) Reactor Vessel Surveillance	Existing program is credited. The program will be enhanced to implement BWRVIP-116 "Integrated Surveillance Program (ISP) Implementation for License Renewal," if approved by the NRC. If BWRVIP-116 is not approved, Exelon will provide a plant-specific surveillance plan for the license renewal period in accordance with 10 CFR 50, Appendices G and H prior to entering the period of extended operation. BWRVIP ISP as specified in BWRVIP-116, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal" and approved by the staff will be implemented. If the ISP is	A.1.23	Prior to the period of extended operation	Section B.1.23

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	not approved two years prior to the commencement of the extended period of operation, a plant-specific surveillance program for Oyster Creek will be submitted. If the Oyster Creek standby capsule is removed from the RPV without the intent to test it, the capsule will be stored in a manner that maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary.			
24) One-Time Inspection	Program is new. The One-Time Inspection program will provide reasonable assurance that an aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect the component or structure intended function during the period of extended operation, and therefore will not require additional aging management. This program will be used for the following: 1. To confirm crack initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or thermal and mechanical loading is not occurring in Class 1 piping less than four-inch nominal pipe size (NPS) exposed to reactor coolant. Inspections will include UT examination of 10% of the total small bore Class I butt welds and destructive or non-	A.1.24	Prior to the period of extended operation Perform prior to the period of extended operation	Section B.1.24

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	destructive examination of a single small bore Class I socket welded connection. 2. To confirm the effectiveness of the Water Chemistry program to manage the loss of material and crack initiation and growth aging effects. Included in the scope of this activity, a one-time UT inspection of the "B" Isolation Condenser shell below the waterline will be conducted looking for pitting corrosion. 3. To confirm the effectiveness of the Closed Cycle Cooling Water System program to manage the loss of material aging effect. 4. To confirm the effectiveness of the Fuel Oil Chemistry program and Lubricating Oil Monitoring Activities program to manage the loss of material aging effect. 5. To confirm loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment. 6. To confirm loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment. 7. To confirm loss of material is insignificant for non-safety related (NSR) piping, piping components, and piping elements of vents and drains, floor and equipment drains, and other systems and components that could contain a fluid, and, are in		Perform prior to the period of extended operation	

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	scope for 10CFR54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities. 8. Two stainless steel pipe sections in a stagnant or low flow area in the Reactor Water Cleanup System, and two stainless steel pipe sections in a stagnant or low flow area in the Isolation Condenser System will be included in the one-time inspection samples for stress corrosion cracking.		Incorporate into program prior to period of extended operation	
25) Selective Leaching of Materials	Program is new. The Selective Leaching of Materials program will consist of inspections of a representative selection of components of the different susceptible materials to determine if loss of material due to selective leaching is occurring. Visual inspections will be consistent with ASME Section XI VT-1 visual inspection requirements and supplemented by hardness tests and other examinations of the selected set of components. If selective leaching is found, the condition will be evaluated to determine the need to expand inspections.	A.1.25	Prior to the period of extended operation	Section B.1.25
26) Buried Piping Inspection	Existing program is credited. The program will be enhanced to include: 1. Inspection of buried piping within ten years of entering the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. The inspections will include at least	A.1.26	Prior to the period of extended operation	Section B.1.26

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	one carbon steel, one aluminum and one cast iron pipe or component. In addition, for each of these materials, the locations selected for inspection will include at least one location where the pipe or component has not been previously replaced or recoated, if any such locations remain. 2. Fire protection components in the scope of the program. 3. Piping located inside the vault in the scope of the program. The vault is considered a manhole that is located between the reactor building and the exhaust tunnel.			
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: 1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years , except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous	A.1.27	Prior to the period of extended operation Prior to the period of extended operation, and then two refueling outages after that. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals	Section B.1.27

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	results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.			
	2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.		Refueling outages prior to and during the period of extended operation	
	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		Periodically Daily during	

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	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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.		refueling outages	
	• The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:		Quarterly during non-outage periods	

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	• Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program Any degraded coating or moisture barrier will be repaired.		Prior to the period of extended operation and every ten years during the period of extended operation	
	4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will		Prior to the period of	

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	be examined every other refueling outage.		extended operation	
	5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.		Every other refueling outage prior to and during the period of extended operation	
	6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to and during the period of extended operation	
	7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are			

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	currently measured. 8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.		Prior to the period of extended operation	
	9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).		Prior to the period of extended operation and two refueling outages later	
	10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be			

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	performed on the same frequency as those in the upper drywell (every other refueling outage). 11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later	
28) ASME Section XI, Subsection IWF	Existing program is credited. The scope of the program will be enhanced to include additional MC supports, and require inspection of the underwater supports for loss of material due to corrosion and loss of mechanical function and loss of preload on bolting by inspecting for missing, detached, or loosened bolts.	A.1.28	Prior to the period of extended operation	Section B.1.28
29) 10 CFR Part 50, Appendix J	Existing program is credited.	A.1.29	Ongoing	Section B.1.29
30) Masonry Wall Program	Existing program is credited. The Masonry Wall Program is part of the Structures Monitoring Program.	A.1.30	Ongoing	Section B.1.30

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31) Structures Monitoring Program	Existing program is credited. The program includes elements of the Masonry Wall Program and the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants aging management program. The Structures Monitoring Program will be enhanced to include: 1. Buildings, structural components and commodities that are not in scope of maintenance rule but have been determined to be in the scope of license renewal. These include miscellaneous platforms, flood and secondary containment doors, penetration seals, sump liners, structural seals, and anchors and embedment. 2. Component supports, other than those in scope of ASME XI, Subsection IWF. 3. Inspection of Oyster Creek external surfaces of mechanical components that are not covered by other programs, HVAC duct, damper housings, and HVAC closure bolting. The scope of this enhancement includes the Reactor Building Closed Cooling Water System carbon steel piping and piping elements located inside the Drywell since operating experience has shown an exposure to an environment conducive to corrosion during outages. Also, to confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the feedwater and main steam system located inside containment, one-time	A.1.31	Prior to the period of extended operation	Section B.1.31

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	visual inspections of feedwater and main steam system piping inside the containment for loss of material due to corrosion will be performed. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting. 4. The visual inspection of insulated surfaces will require the removal of insulation. Removal of insulation will be on a sampling basis that bounds insulation material type, susceptibility of insulated piping or component material to potential degradations that could result from being in contact with insulation, and system operating temperature. 5. Inspection of electrical panels and racks, junction boxes, instrument racks and panels, cable trays, offsite power structural components and their foundations, and anchorage. 6. Periodic sampling, testing, and analysis of ground water to confirm that the environment remains non-aggressive for buried reinforced concrete. 7. Periodic inspection of components submerged in salt water (Intake Structure and Canal, Dilution structure) and in the water of the fire pond dam, including trash racks at the Intake Structure and Canal. 8. Inspection of penetration seals, structural seals, and other elastomers for change in material properties.			

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	9. Inspection of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF, for reduction or loss of isolation function. 10. The current inspection criteria will be revised to add loss of material, due to corrosion for steel components, and change in material properties, due to leaching of calcium hydroxide and aggressive chemical attack for reinforced concrete. Wooden piles and sheeting will be inspected for loss of material and change in material properties. 11. Periodic inspection of the Fire Pond Dam for loss of material and loss of form. 12. Inspection of Station Blackout System structures, structural components, and phase bus enclosure assemblies. 13. Inspection of Forked River Combustion Turbine power plant external surfaces of mechanical components that are not covered by other programs, HVAC duct, damper housings, and HVAC closure bolting. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting. 14. The program will be enhanced to include inspection of Meteorological Tower Structures. Inspection and acceptance criteria will be the same as those specified for other structures in the scope of the			

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	program. 15. The program will be enhanced to include inspection of exterior surfaces of piping and piping components associated with the Radio Communications system, located at the meteorological tower site, for loss of material due to corrosion. Inspection and acceptance criteria will be the same as those specified for other external surfaces of mechanical components. 16. The program will be enhanced to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs for leakage from or onto external surfaces, worn, flaking, or oxide-coated surfaces, corrosion stains on thermal insulation, and protective coating degradation (cracking and flaking). 17. The program will be enhanced to require performing a baseline inspection of submerged water control structures prior to entering the period of extended operation. A second inspection will be performed six years after this baseline inspection and a third inspection eight years after the second inspection. After each inspection, an evaluation will be performed to determine if identified degradation warrant more frequent inspections or corrective actions.			

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32) RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing program is credited. The program is part of the Structures Monitoring Program. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced to include: 1. Monitoring of submerged structural components and trash racks. 2. Periodic inspection of components submerged in salt water (Intake Structure and Canal, Dilution structure) and in the water of the fire pond dam. 3. Periodic inspection of the Fire Pond Dam for loss of material and loss of form. 4. Inspection of steel components for loss of material, due to corrosion. 5. Inspection of wooden piles and sheeting for loss of material and change in material properties. 6. Parameters monitored will be enhanced to include change in material properties, due to leaching of calcium hydroxide, and aggressive chemical attack. Submerged water control structures will be inspected under the Structural Monitoring Program as follows: A baseline inspection of submerged water control structures will be performed prior to entering the period of extended operation. A second inspection will be performed six years after this baseline inspection and a third inspection eight years after the second inspection. After each inspection, an evaluation will be performed	A.1.32	Prior to the period of extended operation	Section B.1.32

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	to determine if identified degradation warrants more frequent inspection or corrective actions.			
33) Protective Coating Monitoring and Maintenance Program	Existing program is credited. The Oyster Creek Protective Coating Monitoring and Maintenance Program provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sand bed region. The program will be enhanced to include: 1. The inspection of Service Level I and Service Level II protective coatings that are credited for mitigating corrosion on interior surfaces of the Torus shell and vent system, and, on exterior surfaces of the Drywell shell in the area of the sandbed region, will be consistent with ASME Section XI, Subsection IWE requirements. 2. Additional visual inspections of the epoxy coating that was applied to the exterior surface of the drywell shell in the sand bed region, such that the coated surfaces in all 10 drywell bays will have been inspected at least once prior to entering the period of extended operation. 3. The inspection of 100% of the sandbed region epoxy coating every 10 years during the period of extended operation. Inspections will be staggered such that at least three bays will be examined every other refueling outage. 4. The inspection of all 20 torus bays at a frequency of	A.1.33	Prior to the period of extended operation	Section B.1.33

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	every other refueling outage for the current coating system. Should the current coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.			
34) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Program is new. The program will be used to manage aging of non-EQ cables and connections during the period of extended operation. A representative sample of accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of accelerated insulation aging.	A.1.34	Prior to the period of extended operation	Section B.1.34
35) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Existing program is credited. The program will be enhanced to include: 1. A review of the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring system calibration results for cable aging degradation before the period of extended operation and every 10 years thereafter. 2. A review of the LPRM/APRM and IRM system cable testing results for cable aging degradation before the period of extended operation and every 10 years thereafter.	A.1.35	Prior to the period of extended operation	Section B.1.35
36) Inaccessible Medium Voltage Cables Not Subject	Program is new. The program manages the aging of inaccessible medium-voltage cables (2.4 kV, 4.16 kV, 13.8 kV and 34.5 kV) that feed equipment performing	A.1.36	Prior to the period of extended operation	Section B.1.36

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to 10 CFR 50.49 Environmental Qualification Requirements	license renewal intended functions. These cables may at times be exposed to moisture and are subjected to system voltage for more than 25% of the time. Manholes, conduits and sumps associated with these cables will be inspected for water collection every 2 years and drained as required. In addition, the cable circuits will be tested using a proven test for detecting deterioration of the insulation system due to wetting, such as power factor or partial discharge, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. The cable circuits will be tested at an initial frequency of six years, after which the frequency will be evaluated and adjusted, based on test results; the period between tests shall not exceed 10 years. Results of cable tests will be trended. Trending will occur at the same frequency as cable testing. Inclusion of the 13.8 kV system circuits in this program reflects the scope expansion of the Station Blackout System electrical commodities. Inclusion of the 34.5 kV system circuits in this program reflects the scope enhancement for reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.			
37) Periodic Testing of Containment Spray Nozzles	Existing plant specific program is credited. Carbon steel piping upstream of the drywell and torus spray nozzles is subject to possible general corrosion. The	A.2.1	Ongoing	Section B.2.1

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	periodic flow tests of drywell and torus spray nozzles address a concern that rust from the possible general corrosion may plug the spray nozzles. These periodic tests verify that the drywell and torus spray nozzles are free from plugging that could result from corrosion product buildup from upstream sources.			
38) Lubricating Oil Monitoring Activities	Existing plant specific program is credited. The program manages loss of material, cracking, and fouling in lubricating oil heat exchangers, systems, and components in the scope of license renewal by monitoring physical and chemical properties in lubricating oil. Sampling, testing, and monitoring verify lubricating oil properties. Oil analysis permits identification of specific wear mechanisms, contamination, and oil degradation within operating machinery, and components of systems in scope for license renewal. The program will be enhanced to add surveillance for verification of flow through the Fire Protection System diesel driven pump gearbox lubricating oil cooler. AmerGen will enhance Oyster Creek Program B.2.2 to include sampling and measurement of flash point of diesel engine lubricating oil to detect contamination of lubricating oil by fuel oil.	A.2.2	Prior to the period of extended operation	Section B.2.2
39) Generator Stator Water Chemistry	Existing plant specific program is credited. The program manages loss of material aging effects by	A.2.3	Ongoing	Section B.2.3

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Activities	monitoring and controlling water chemistry. Generator stator water chemistry control maintains high purity water in accordance with General Electric and EPRI guidelines for stator cooling water systems.			
40) Periodic Inspection of Ventilation Systems	Existing plant specific program is credited. The program includes internal and external surface inspections of ventilation system components for indications of loss of material, such as rust, corrosion and pitting. Heat transfer surfaces are inspected for fouling. Flexible connection and door seal elastomer materials are inspected for detrimental changes in material properties, as evidenced by cracking, perforations in the material or leakage. The program will be enhanced to include duct exposed to soil, instrument piping and valves, restricting orifices and flow elements, and thermowells. The activities will also be enhanced to include inspection guidance for detection of the applicable aging effects.	A.2.4	Prior to the period of extended operation	Section B.2.4
41) Periodic Inspection Program	Plant specific program is new. The program includes systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Activities consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of identified aging effects. The inspections are condition monitoring examinations intended to assure that existing environmental conditions are not causing material degradation that	A.2.5	Prior to the period of extended operation	Section B.2.5

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	could result in a loss of system intended functions.			
42) Wooden Utility Pole Program	Plant specific program is new. The program is used to manage loss of material and change of material properties for wooden utility poles in or near the Oyster Creek Substation that provide structural support for the conductors connecting the Offsite Power System and the 480/208/120V Utility (JCP&L) Non-Vital Power System to the Oyster Creek plant. The program consists of inspection on a 10-year interval by a qualified inspector. The wooden poles are inspected for loss of material due to ant, insect, and moisture damage and for change in material properties due to moisture damage.	A.2.6	Prior to the period of extended operation	Section B.2.6
43) Periodic Monitoring of Combustion Turbine Power Plant - Electrical	A new plant specific program is credited. The program will be used in conjunction with the existing Structures Monitoring Program, the new Inaccessible Medium Voltage Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements program and the new Electrical Cable Connections Not Subject to 10CFR 50.49 Environmental Qualification Requirements program to manage aging effects for the electrical commodities that support FRCT operation. The Program consists of visual inspections of accessible electrical cables and connections exposed in enclosures, pits, manholes and pipe trench; visual inspection for water collection in manholes, pits, and trenches, located on the FRCT site, for inaccessible medium voltage cables; and visual inspection of	A.1.37	Prior to the period of extended operation	Section B.1.37

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	accessible phase bus and connections and phase bus insulators/supports; and visual inspection of high voltage insulators above 34.5 kV for salt build-up. The new program will be performed on a twice per year frequency for high voltage insulator inspections; on a 2-year interval for manhole, pit and trench inspections, on a 5-year frequency for phase bus inspections, and on a 10-year interval for cable and connection inspections.			
44) Metal Fatigue of Reactor Coolant Pressure Boundary	Existing program is credited. The program will be enhanced to use the EPRI-licensed FatiguePro cycle counting and fatigue usage factor tracking computer program. The computer program provides for calculation of stress cycles and fatigue usage factors from operating cycles, automated counting of fatigue stress cycles and automated calculation and tracking of fatigue cumulative usage factors. The program will also be enhanced to provide for calculating and tracking of the cumulative usage factors for bounding locations for the reactor pressure vessel, Class I piping, the torus, torus vents, torus attached piping and penetrations, and the isolation condenser. AmerGen will revise the Oyster Creek UFSAR to update the current licensing basis to reflect that a cumulative usage factor of 1.0 will be used in fatigue analysis for reactor coolant pressure boundary components, as endorsed by the NRC in 10 CFR 50.55a.	A.3.1	Prior to the period of extended operation Prior to the period of extended operation	Section B.3.1

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	Certification by a Professional Engineer of the reactor vessel design specification and design reports prepared for the fatigue activities associated with the Oyster Creek License Renewal Application will be performed.		Prior to the period of extended operation	
45) Environmental Qualification (EQ) Program	Existing program is credited. EQ components that cannot be qualified for 60-years will be replaced before the end of their qualified life.	A.3.2	Ongoing	Section B.3.2
46) New P-T curves	Revised pressure-temperature (P-T) limits for a 60-year licensed operating life have been prepared and will be submitted to the NRC for approval.	A.4.1.3	Prior to the period of extended operation	Section 4.2.3
47) Circumferential Weld Exam Relief	Apply for extension Reactor Vessel Circumferential Weld Examination Relief for 60-year operation	A.4.1.4	Prior to the period of extended operation	Section 4.2.4
48) Axial weld Exam Relief	Apply for extension Reactor Vessel Axial Weld Examination Relief for 60-year operation	A.4.1.5	Prior to the period of extended operation	Section 4.2.5
49) Measure Drywell wall thickness	Drywell wall thickness will be monitored to ensure minimum wall thickness is maintained. The ASME Section XI, Subsection IWE aging management program, will manage the aging effects.	A.4.5.2	Ongoing	Section 4.7.2
50) Fluence Methodology	The NRC has issued a SER for RAMA approving RAMA for reactor vessel fluence calculations. Oyster Creek will comply with the applicable requirements of the SER.	A.4.1.1	Prior to the period of extended operation.	Section 4.2.1
51) Bolting Integrity - FRCT	The Bolting Integrity - FRCT aging management program is a new program that provides for condition monitoring of bolts and bolted joints within the scope of license renewal at the Forked River Combustion	A.1.12A	Prior to the period of extended operation	Section B.1.12A

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	Turbine power plant. This program is based on the General Electric recommendations for proper bolting material selection, lubrication, preload application, installation and maintenance associated with the combustion turbine units and auxiliary systems. The program also includes periodic walkdown inspections for bolting degradation or bolted joint leakage at a frequency of at least once every four years. The program manages the loss of material and loss of preload aging effects. This new program will be implemented prior to entering the period of extended operation.			
52) Closed-Cycle Cooling Water System - FRCT	The Closed-Cycle Cooling Water System – FRCT aging management program is a new program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and cracking, and are exposed to a closed cooling water environment at the Forked River Combustion Turbine power plant. The Closed-Cycle Cooling Water System – FRCT aging management program relies on preventive measures to minimize corrosion by maintaining water chemistry control parameters and by performing system monitoring and maintenance inspection activities to confirm that the aging effects are adequately managed. Chemistry control, performance monitoring and inspection activities are based on industry-recognized guidelines of EPRI TR-107396,	A.1.14A	Prior to the period of extended operation	Section B.1.14A

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	"Closed Cooling Water Chemistry Guidelines," for closed-cycle cooling water systems. Chemical control parameters will be monitored by annual water chemistry sampling. System operational monitoring activities will be performed at a frequency of at least once every six months. This new program will be implemented prior to entering the period of extended operation.			
53) Aboveground Steel Tanks - FRCT	The Above ground Steel Tanks - FRCT aging management program is a new program that will manage corrosion of aboveground outdoor steel tanks. Paint coating is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint coating and any resulting metal degradation of tank external surfaces. The aboveground tanks external surfaces will be visually inspected for coating degradation by walkdown at least once every two years. The Main Fuel Oil tank bottom is in contact with concrete and soil, and is inaccessible for visual inspection. Therefore, the program includes periodic Non-destructive wall-thickness examinations of the Main Fuel Oil tank bottom to verify that significant corrosion is not occurring. This program, including the initial tank external paint inspections, will be implemented prior to the period of extended operation. The recommended UT inspection of the Main Fuel Oil tank bottom was performed in	A.1.21A	Prior to the period of extended operation	Section B.1.21A

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections, and subsequent repairs to the tank floor, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional UT inspections will be performed prior to October 2020.			
54) Fuel Oil Chemistry – FRCT	The Fuel Oil Chemistry - FRCT aging management program is a new program that provides assurance that contaminants are maintained at acceptable levels in new and stored fuel oil for systems and components within the scope of Licensing Renewal. The Fuel Oil Storage Tank will be maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing Materials (ASTM). Fuel oil sampling activities will be in accordance with ASTM D 4057 for multilevel and tank bottom sampling. Fuel oil will be periodically sampled and analyzed for particulate contamination in accordance with modified ASTM Standard D 2276 Method A or ASTM Standard D 6217, and, for the presence of water and sediment in accordance with ASTM Standard D 2709 or ASTM Standard D 1796. The Fuel Oil Storage Tank will be periodically drained of accumulated water and sediment and will be	A.1.22A	Prior to the period of extended operation	Section B.1.22A

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations. This new program will be implemented prior to entering the period of extended operation. The internal inspection of the Main Fuel Oil tank was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections and repairs, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional internal inspections of the tank floor are not necessary prior to entering the period of extended operation and will be performed prior to October 2020.			
55) One-Time Inspection - FRCT	The One-Time Inspection – FRCT program will provide measures to verify that an aging management program is not needed, confirms the effectiveness of existing activities, or determines that degradation is occurring which will require evaluation and corrective action. The program will be implemented prior to the period of extended operation. Inspection methods will include visual examination or volumetric examinations. Should aging effects be	A.1.24A	Prior to the period of extended operation	Section B.1.24A

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	detected, the program will initiate actions to characterize the nature and extent of the aging effect and determines what subsequent monitoring is needed to ensure intended functions are maintained during the period of extended operation.			
56) Selective Leaching of Materials -FRCT	The Selective Leaching of Materials - FRCT aging management program is a new program that will consist of inspections of components constructed of susceptible materials to determine if loss of material due to selective leaching is occurring. For the FRCT power plant, these are limited to copper alloy materials exposed to a closed cooling water environment. One-time inspections will consist of visual inspections supplemented by hardness tests. If selective leaching is found, the condition will be evaluated to determine the ability of the component to perform its intended function until the end of the period of extended operation and for the need to expand inspections. This new program will be implemented in the time period after January 2018 and prior to January 2028.	A.1.25A	This new program will be implemented in the time period after January 2018 and prior to January 2028	Section B.1.25A
57) Buried Piping Inspection – FRCT	The Buried Piping Inspection - FRCT aging management program is a new program that manages the external surface aging effects of loss of material for carbon steel piping and piping system components in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping and piping system	A.1.26A	Prior to the period of extended operation	Section B.1.26A

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	components in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of glycol cooling water piping located at the Forked River Combustion Turbine station. External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.			
58) Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components- FRCT	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT aging management program is a new program that consists of visual inspections of the internal surfaces of steel piping, valve bodies, ductwork, filter housings, fan housings, damper housings, mufflers and heat exchanger shells in the scope of license renewal at the Forked River Combustion Turbine power plant that are not covered by other aging management programs. Internal inspections will be performed during scheduled maintenance activities when the surfaces are made	A.1.38	Inspection for CT Unit 1 will be performed by May 2014, and inspection for CT Unit 2 will be performed by November 2015	Section B.1.38

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. These inspections will be performed during the major combustion turbine inspection outages and will be performed on a frequency of at least once every 10 years. The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.			
59) Lubricating Oil Analysis Program – FRCT	The Lubricating Oil Analysis Program – FRCT is a new program that includes measures to verify the oil environment in mechanical equipment is maintained to the required quality. The Lubricating Oil Analysis Program – FRCT maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction in heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup. The program will also include the measurement of flash point. This program is	A.1.39	Prior to the period of extended operation	Section B.1.39

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	augmented by the One Time Inspection – FRCT (B.1.24A) program, to verify the effectiveness of the Lubricating Oil Analysis Program - FRCT. This new program will be implemented prior to the period of extended operation.			
60) Periodic Inspection Program - FRCT	The Periodic Inspection Program - FRCT is a new program that will consist of periodic inspections of selected components to verify the integrity of the system and confirm the absence of identified aging effects. Inspections will be scheduled to coincide with major combustion turbine maintenance inspections, when the subject components are made accessible. These inspections will be performed on a frequency not to exceed once every 10 years. The purpose of the inspection is to determine if a specified aging effect is occurring. If the aging effect is occurring, an evaluation will be performed to determine the effect it will have on the ability of affected components to perform their intended functions for the period of extended operation, and appropriate corrective action is taken. Inspection methods may include visual examination, surface or volumetric examinations. When inspection results fail to meet established acceptance criteria, an evaluation will be conducted to identify actions or measures necessary to provide reasonable assurance that the component intended function is maintained during the period of extended operation. The initial inspections associated with this program will	A.2.5A	Inspection for CT Unit 1 will be performed by May 2014, and inspection for CT Unit 2 will be performed by November 2015	Section B.2.5A

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.			
61) Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply	The Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply aging management program is a new program that manages the external surface aging effects of loss of material for copper and carbon steel piping, and carbon steel tanks in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping and tanks in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of the Met Tower based radio communications system repeater backup engine generator fuel (propane) supply piping and the associated buried fuel supply tank, located at the Meteorological Tower. External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of	A.1.26B	Prior to period of extended operation	Section B.1.26B

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	buried piping will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.			
62)	AmerGen will commit to perform monitoring of any leakage from the spent fuel pool liner via the pool leak chase piping.		Prior to the period of extended operation	GALL Reconciliation Letter 2130-06-20293
63)	AmerGen will replace the previously un-replaced, buried safety-related ESW piping prior to the period of extended operation.		Prior to the period of extended operation	Letter 2130-06-20328
64) Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage the aging effects of metallic parts of non-EQ electrical cable connections within the scope of license renewal during the period of extended operation. A representative sample of non-EQ electrical cable connections will be selected for testing considering application (high, medium and low voltage), circuit loading and location, with respect to connection stressors. The type of test to be performed, i.e., thermography, is a proven test for detecting loose connections. A representative sample of non-EQ cable	A.1.40	Prior to the period of extended operation	Section B.1.40

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	connections will be tested at least once every 10 years. This new program will be implemented prior to the period of extended operation.			
65) Corrective Action, Confirmation and Administrative Controls for Forked River Combustion Turbine activities	Prior to the period of extended operation, AmerGen will ensure that procedures are established to implement the program elements of Corrective Action, Confirmation, and Administrative Controls, as described in Sections A.0.5 and B.0.3 of Enclosure 1 of AmerGen letter 2130-06-20334, for the Forked River Combustion Turbine aging management activities.	A.0.5	Prior to the period of extended operation	B.0.3

Oyster Creek Document Distribution Sheet

TITLE/SUBJECT: **Updated FSAR Supplement Information Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)**

COGNIZANT INDIVIDUAL: **Fred Polaski**

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STANDARD RECORDS RETENTION SCHEDULE #	FILE CODE / (REFERENCE #)	RECORD NUMBER	RECORD NAME	RECORD DATE
	05040	2130-06-20354	Updated FSAR Supplement Information Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)	6/23/06

AmerGen

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20358
July 7, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Additional Information Concerning FSAR Supplement Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)

Reference: AmerGen's Letter 2130-06-20354 "Updated FSAR Supplement Information Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624), dated June 23, 2006

In the referenced letter, AmerGen Energy Company, LLC (AmerGen) provided the NRC an update to FSAR Supplement information previously provided in its application for a renewed operating license for Oyster Creek Generating Station (Oyster Creek). Subsequent NRC staff review identified the need to add clarifying details to the Oyster Creek aging management programs as described in Sections A.1.10, A.1.12, A.1.23 and A.1.27 of the License Renewal Application (LRA).

This letter provides the necessary information. Enclosure 1 provides updates to the FSAR Supplement program descriptions (Sections A.1.10, A.1.12, A.1.23 and A.1.27 of the LRA). Enclosure 2 provides a summary of the impacts, if any, of these clarifications to the License Renewal Commitment List (Section A.5 of the LRA).

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 07-07-2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosures: 1. Updated FSAR Supplement Program Descriptions
2. Changes to License Renewal Commitments

cc: Regional Administrator, USNRC Region I, w/o Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/o Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

ENCLOSURE 1

Updated FSAR Supplement Program Descriptions
Sections A.1.10, A.1.12, A.1.23 and A.1.27

Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

Note: Information within the following Appendix A Sections that is new since AmerGen June 23, 2006 Letter 2130-06-20354 is presented in bold font for ease of identification.

A.1.10 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless steel (CASS) aging management program is a new program that will provide for aging management of CASS reactor internal components within the scope of license renewal. The program will be implemented prior to the period of extended operation.

The program will include a component specific evaluation of the loss of fracture toughness in accordance with the criteria specified in NUREG 1801, XI.M13. **This detailed component-specific evaluation is a generic industry activity that is being addressed by the BWRVIP. The evaluation is currently budgeted for completion in 2007, after which Oyster Creek will implement the requirements of the BWRVIP guidelines. If industry activities do not complete in a timely manner, AmerGen will perform the required evaluations. In either case, the following information will be submitted to the NRC at least one year prior to the period of extended operation: 1) the type and composition of CASS reactor internal components within the scope of license renewal; and 2) the results of evaluations performed to determine susceptibility to thermal aging and neutron irradiation embrittlement.** For those components where loss of fracture toughness may affect function of the component, a supplemental inspection will be performed. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.

A.1.12 Bolting Integrity

The Bolting Integrity aging management program is an existing program that incorporates industry recommendations of EPRI NP 5769, "Degradation and Failure of Bolting in Nuclear Power Plants," and includes periodic visual inspections of closure bolting for loss of bolting function. Inspection of Class 1, 2, and 3 components is conducted in accordance with ASME Section XI. The requirements of ASME Section XI will be implemented in accordance with 10 CFR 50.55(a). The Oyster Creek program addresses the guidance contained in EPRI TR-104213, Bolted Joint Maintenance & Applications Guide, however the report is not specifically cited as a reference in the Exelon corporate or stations' specific bolted joint inspection/repair procedures. Site procedures will be enhanced to include reference to EPRI TR-104213, Bolted Joint Maintenance & Application Guide, December 1995.

Non-ASME Class 1, 2 and 3 bolted joint inspections rely on detection of visible leakage during maintenance or routine observation. **If these pressure retaining bolted joint connections are observed to be leaking, then the leakage is evaluated as part of the corrective action process. The corrective action process may allow for pressure retaining components (not covered by ASME Section XI) that are reported to be leaking to be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly.**

The Bolting Integrity program does not address Primary Containment pressure retaining, structural and component support bolting. Primary Containment pressure retaining bolting are addressed by ASME Section XI, Subsection IWE, B.1.27. The Structures

Monitoring Program, B.1.31 addresses the aging management of structural bolting. The ASME Section XI, Subsection IWF program, B.1.28, addresses aging management of ASME Section XI Class 1, 2, and 3 and Class MC support members.

A.1.23 Reactor Vessel Surveillance

The Oyster Creek Reactor Vessel Surveillance aging management program is an existing program that monitors the effects of neutron embrittlement on the reactor vessel beltline materials. The program is based on the BWR Integrated Surveillance Program (ISP) and satisfies the requirements of 10 CFR 50, Appendix H. The Reactor Vessel Surveillance program is based upon BWRVIP-78, "BWR Vessel and Internals Project: BWR Integrated Surveillance Program Plan", and BWRVIP-86-A, "BWR Vessel and Internals Project Updated BWR Integrated Surveillance Program (ISP) Implementation Plan". The program will ensure coupon availability during the period of extended operation by saving withdrawn coupons for future reconstitution.

Oyster Creek will enhance the program to implement BWRVIP-116 "**BWR Vessel and Internals Project** Integrated Surveillance Program (ISP) Implementation for License Renewal," **including the conditions specified by the NRC in its Safety Evaluation dated February 24, 2006.**

If the Oyster Creek standby capsule is removed from the RPV without the intent to test it, the capsule will be stored in a manner that maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary.

A.1.27 ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic inspection of primary containment surfaces and components, including integral attachments, and containment vacuum breakers system piping and components for loss of material, loss of sealing, and loss of preload.

Examination methods include visual and volumetric testing as required by the Code. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action process. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied to bolting.

In accordance with commitments made during the Oyster Creek license renewal application review process, the program will be enhanced to include:

1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection to provide early confirmation that corrosion has been arrested. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals. The UT measurements will be taken from the inside of the drywell at the same locations

where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:

- Perform additional UT measurements to confirm the readings.
- Notify NRC within 48 hours of confirmation of the identified condition.
- Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected.
- Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity.
- Perform operability determination and justification for operation until next inspection.

These actions will be completed prior to restart from the associated outage.

2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:
   - 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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.
   - The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:

     - Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
     - UTs of the upper drywell region consistent with the existing program
     - UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred
     - UT results will be evaluated per the existing program
     - Any degraded coating or moisture barrier will be repaired

4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of

the inspections will be staggered such that at least three bays will be examined every other refueling outage.

5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.

7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.

9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).

10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the

upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

12. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected **per the Protective Coatings Program**.

13. **The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.**

ENCLOSURE 2

Changes to License Renewal Commitments

Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

The following table identifies modifications made to previous license renewal commitments, being made in this supplemental response. The new information is displayed in bold font. Any other actions discussed in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments.

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
10) Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Program is new. The program will include a component specific evaluation of the loss of fracture toughness in accordance with the criteria specified in NUREG-1801, XI.M13. **At least one year prior to the period of extended operation, the following information will be submitted to the NRC: 1) the type and composition of CASS reactor internal components within the scope of license renewal; and 2) the results of evaluations performed to determine susceptibility to thermal aging and neutron irradiation embrittlement.** For those components where loss of fracture toughness may affect the intended function of the component, a supplemental inspection will be performed. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.	A.1.10	Prior to the period of extended operation	Section B.1.10
23) Reactor Vessel Surveillance	Existing program is credited. The program will be enhanced to implement BWRVIP-116 "**BWR Vessel and Internals Project** Integrated Surveillance Program (ISP) Implementation for License Renewal," **including the conditions specified by the NRC in its Safety Evaluation dated February 24, 2006**. If the Oyster Creek standby capsule is removed from the RPV without the intent to test it, the capsule will be	A.1.23	Prior to the period of extended operation	Section B.1.23

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	stored in a manner that maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary.			
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: 1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas	A.1.27	Prior to the period of extended operation Prior to the period of extended operation, and then two refueling outages after that. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals	Section B.1.27

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.			
	2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.		Refueling outages prior to and during the period of extended operation	
	3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage.		Periodically	
	• 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 and performance of UT examinations of the shell in the upper		Daily during refueling outages	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE

	regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.
	• The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:
	  • Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
	  • UTs of the upper drywell region consistent with the existing program
	  • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred
	  • UT results will be evaluated per the existing program
			Quarterly during non-outage periods	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	Any degraded coating or moisture barrier will be repaired.			
	4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.		Prior to the period of extended operation and every ten years during the period of extended operation	
	5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original		Prior to the period of extended operation	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	design configuration using concrete or other suitable material to prevent moisture collection in these areas.			
	6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to and during the period of extended operation	
	7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.		Every other refueling outage prior to and during the period of extended operation	
	8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.			
	9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either		Prior to the period of extended operation	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).			
	10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later	
	11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will		Prior to the period of extended operation and two refueling outages later	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	be performed on the same frequency as those in the upper drywell (every other refueling outage).			
	12. When the sand bed region drywell shell coating inspection is performed (commitment 27, item 4), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.		**Coincident with the sand bed region drywell shell coating inspection**	
	13. The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.		**Once per refueling cycle**	

Oyster Creek Document Distribution Sheet

TITLE/SUBJECT: **Additional Information Concerning FSAR Supplement Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)**

COGNIZANT INDIVIDUAL: **Fred Polaski**

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Other

K. Barnes	OCAB-2	E
C. Duffy	OCAB-2	E
R. Skelsky	OCAB	E
J. Barbieri	OCAB	E
P. Tamburro	OCAB	E
G. Harttraft	OCAB	E
G. Martinez	OCAB	E
C. Schilling	OCAB	E

STANDARD RECORDS RETENTION SCHEDULE #	FILE CODE / (REFERENCE #)	RECORD NUMBER	RECORD NAME	RECORD DATE
	05040	2130-06-20358	Additional Information Concerning FSAR Supplement Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)	7/7/06

AmerGen

Michael P. Gallagher, PE
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License Renewal Projects

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20360
July 7, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)

References:

1. NRC's "Request for Additional Information for the Review of the Oyster Creek Nuclear Generating Station, License Renewal Application (TAC 7624)", dated March 10, 2006

2. AmerGen's "Response to NRC Request for Additional Information, dated March 10, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. 7624)," dated April 7, 2006

3. NRC's "Summary of Meeting Held on June 1, 2006, Between the U.S. Nuclear Regulatory Commission Staff and AmerGen Energy Company, LLC Representatives to Discuss the Staff's Questions Regarding the Drywell Shell and the Oyster Creek Nuclear Generating Station License Renewal Application," dated June 9, 2006 (ADAMS # ML061600368)

In Reference 1, as part of its review of the AmerGen Energy Company (AmerGen) application for license renewal for Oyster Creek Generating Station (Oyster Creek), the NRC Staff requested additional information regarding the aging management program and activities associated with the Oyster Creek drywell containment shell. Reference 2 provided AmerGen's response to these RAIs.

On June 1, 2006, the NRC Staff held a public meeting with representatives from AmerGen to further discuss the drywell aging management program. At that meeting, the Staff posed several specific clarifying questions to AmerGen, as documented in Reference 3. The Staff also indicated that it plans to conduct an engineering analysis of the drywell to confirm the results of General Electric (GE) analysis submitted to the NRC in 1991 and resubmitted in response to RAI 4.7.2-1 (b), Reference 2. Attachment 1 of this letter provides construction drawings requested by the Staff to support its analysis of the containment drywell.

Attachment 1 begins with the list of drawings contained in Attachment 1, followed by the submitted drawings. These drawings contain information proprietary to Chicago Bridge & Iron Company (CB&I). On behalf of CB&I, AmerGen requests that the documents be withheld from public disclosure in accordance 10 CFR 2.390 (a)(4). An affidavit supporting this request is included as Attachment 2.

Attachment 3 contains additional drawings that are not considered proprietary, and are therefore grouped as a separate attachment.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 07-07-2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Attachment
1. Oyster Creek Containment Fabrication Drawings - Proprietary
2. Chicago Bridge & Iron Company - Proprietary Affidavit
3. Oyster Creek Containment Drawings – Non-Proprietary

cc: Regional Administrator, USNRC Region I, w/o Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/o Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

ATTACHMENT 1 – LIST OF SELECTED OYSTER CREEK CONTAINMENT FABRICATION DRAWINGS REQUESTED TO WITHHOLD INFORMATION FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390

Vendor	Drawing No.	Sheet No	Revision	Drawing Title	
CB & I	9-0971	1	2	General Plan – Pressure Suppression containment Vessels	
		2	10	Drywell Shell Stretchout	
		2A	4	Penetration Schedule	
		3	2	Field Assembly of Drywell Shell	
		4	1	Drywell Field Weld Joints	
		7	5	Shop Details - Drywell Cylinder Shell & Top Head Flange	
		8	3	Shop Details - Drywell Shell Plate Assemblies	
		9	2	Shop Details - Drywell Shell Plate Assemblies	
		11	2	Erection Skirt Details	
		21	1	Shop & Field – 7'-10 Dia. Vent Assembly	
		25	2	Shop & Field - Drywell Penetration Details	
		26	2	Shop & Field - Drywell Penetration Details	
		29	7	33'-0" Diameter Flange Assembly	
		30	5	Drywell – Field Details For 33'-0" Flanges	
		31	5	Drywell Shop Details for 33'-0 Dia. Flanges	
		32	2	Drywell – Welding Pads	
		34	4	Drywell – Lower Beam Seats	

ATTACHMENT 1 – LIST OF SELECTED OYSTER CREEK CONTAINMENT FABRICATION DRAWINGS REQUESTED TO WITHHOLD INFORMATION FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390

		35	4	Drywell Upper Beam Supports	
		36	4	Drywell Stabilizer	
		37	5	Female Stabilizer Assembly	
		40	2	Equipment Hatch Penetration	
		55	7	Suppression Chamber Field Assembly of Column, Support Ring, & Vent Header Support	
		61	6	Suppression Chamber Field Assembly of Header & Vent System	
		62	3	Suppression Chamber Shop Details of Vent Pipe	
		66	2	Suppression Chamber Shop Assembly of Vent Insert	
		69	3	Suppression Chamber Shop Details & Assembly of Sway Braces	
		70	5	Vent Header Replacement Support Columns Shop Assy.	
		72	5	Vent Header Replacement Support Column Piece Details	
		80	1	Vent Header Replacement Support Columns Field Installation	
		100	2	General Arrangement 2-6 x 6-0 Personnel Lock	
		101	1	2-6 x 6-0 Personnel Lock Structural Assembly	
		102	5	2-6 x 6-0 Personnel Lock Interior Bulkhead Assembly	
		103	2	2-6 x 6-0 Personnel Lock Exterior Bulkhead Assembly	

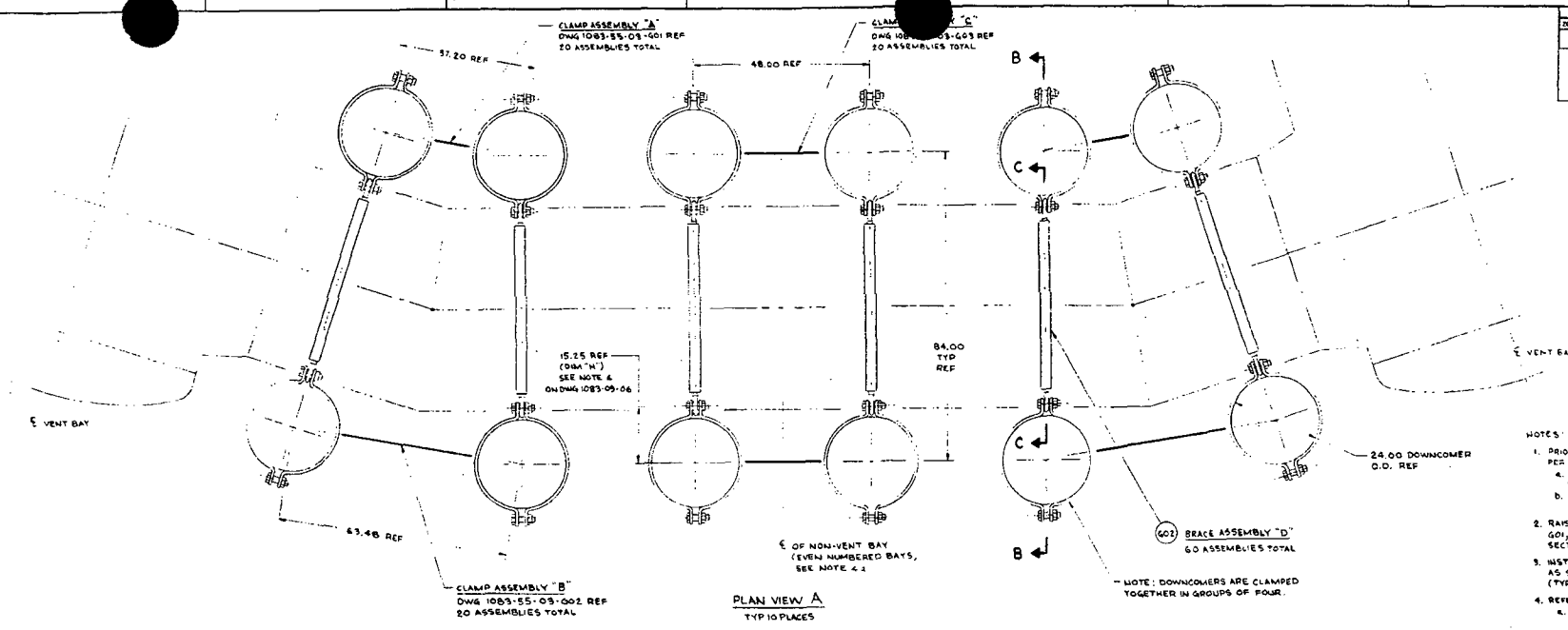
Proprietary Information

CB&I Drawings

To be provided by NRC Staff

1083-09-05	1	B	Torus Downcomer Lateral Support System Installation
1083-09-06	1	B	Torus Downcomer Lateral Support System Details
1083-09-07	1	D	Vent Header Replacement Support Columns Fabrication and Installation

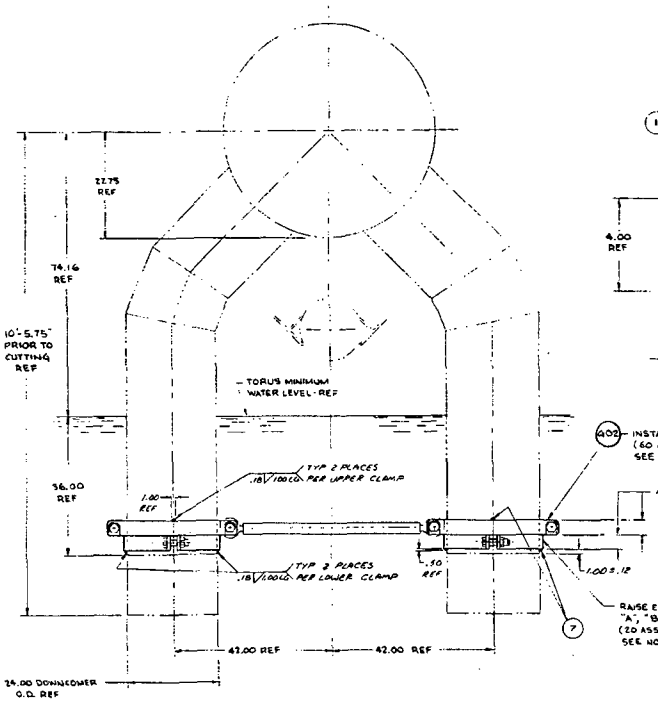
ZONE	LTR	DESCRIPTION	APPROVAL	
	A	ORIGINAL ISSUE		
	B	602 WAS CLAMP ASSY "D". 17.E WAS COLUMN WELDMENT. 17.3 WAS SPACER. 17.6 WAS LOCKWIRE. DELETED DETAIL E. ADDED 17.7 TO SECTION B-B	KEW 6/6/79	



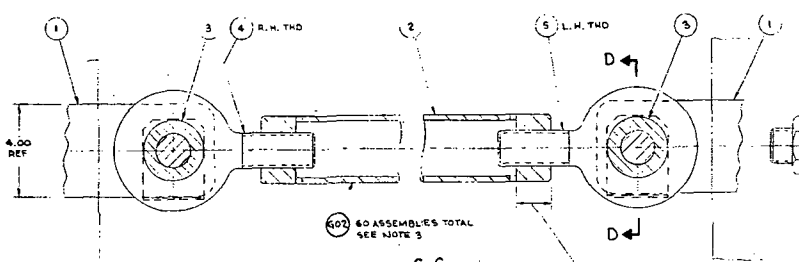
PLAN VIEW A
TYP 10 PLACES

NOTES:

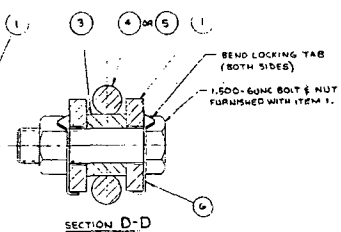
1. PRIOR TO (OR IN CONJUNCTION WITH) INSTALLING BRACE ASSEMBLIES PER THIS DWG:
   a. CUT DOWNCOMERS 36.00" BELOW TORUS MINIMUM WATER LEVEL. (TYP 120 PLACES).
   b. REMOVE EXISTING STRONGBACK ASSEMBLIES, SEE ITEM 604 OF DWG 1083-55-03. (TYP 60 PLACES).
2. RAISE EXISTING CLAMP ASSEMBLIES "A", "B", & "C" (ITEMS 601, 602, & 603 OF DWG 1083-55-03.) AS SHOWN AT SECTION B-B. (TYP 60 PLACES TOTAL)
3. INSTALL NEW BRACE ASSEMBLY "D" (ITEM 602 OF THIS DWG) AS SHOWN AT VIEW A & SECTIONS B-B & C-C (TYP 60 PLACES TOTAL).
4. REFERENCE DWGS:
   a. PLAN VIEW OF TORUS - SHOWS ALL BAY NUMBERS & AZIMUTH LOCATIONS - SEE DWG 1083-09-01 SHEET 1.
   b. PREVIOUS LATERAL SUPPORT SYSTEM INSTALLATION - SEE DWG 1083-55-03 (NOTE: CLAMP ASSEMBLIES "A", "B", & "C" ARE TO BE USED ON THIS NEW INSTALLATION. THE STRONGBACK ASSEMBLIES ARE NOT USED ON THIS NEW INSTALLATION).



SECTION B-B
TYP 60 PLACES TOTAL
(ROTATED 90° CW)



SECTION C-C
TYP 60 PLACES TOTAL
(ROTATED 90° CW)
SCALE: 1/2



SECTION D-D
TYP BOTH ENDS

QTY REQD				PART NO	DESCRIPTION	MATERIAL / SPECIFICATION	ITEM NO
	480			1083-09-06 ITEM 7	BAR		7
2				1083-09-06, ITEM 6	LOCKING TAB		6
1				1083-09-06, ITEM 5	EYE BOLT (L.H. THD)		5
1				1083-09-06, ITEM 4	EYE BOLT (R.H. THD)		4
2				1083-09-06, ITEM 3	EYEBOLT BUSHING		3
1				1083-09-06, 601	STRUT WELDMENT		2
2		V		FIG. 221 24" SIZE	PIPE CLAMP	POWER PIPING CO PITTSBURGH, PA. (CARBON STL)	1
	60				BRACE ASSEMBLY "D"		602
					INSTALLATION		601
602	601	SYM	CODE IDENT NUMBER	PART NO	DESCRIPTION	MATERIAL / SPECIFICATION	ITEM NO

SYM: V = VENDOR ITEM

PARTS LIST

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES.
TOLERANCES
2 PLACE ± | 3 PLACE ± | ANGLES ±
DO NOT SCALE.
NEXT ASSEMBLY

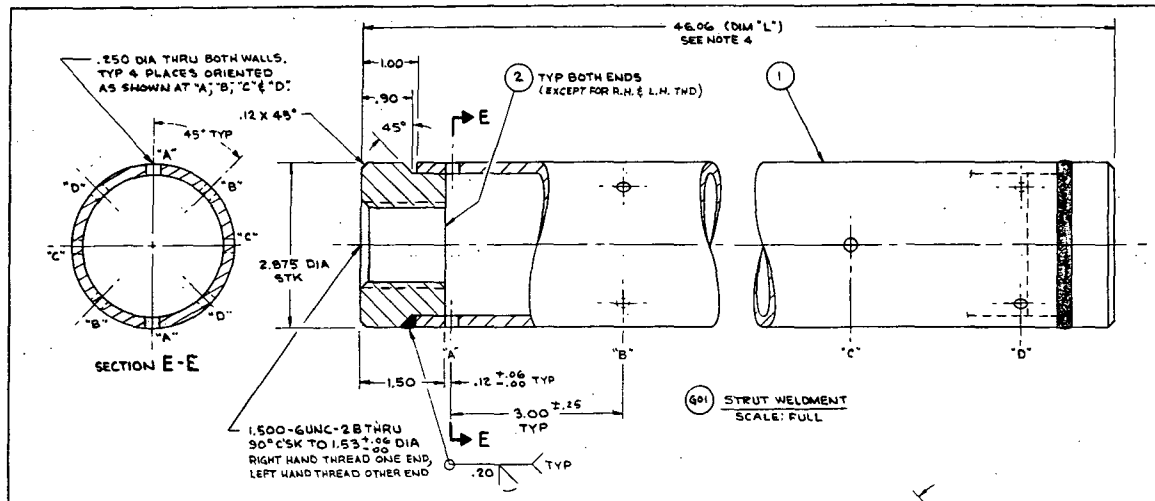
CONTRACT NUMBER
DRAFTSMAN CA — DATE 6-6-79
CHECKER — DATE
HEAD OF DESIGN — DATE
ENGINEER — DATE

MPR ASSOCIATES, INC.
1140 CONNECTICUT AVE. N.W. WASHINGTON, D.C. 20036

TITLE: OYSTER CREEK SENSORING STATION
TORUS DOWNCOMER LATERAL SUPPORT SYSTEM INSTALLATION

SIZE E | CODE IDENT NO. — | DWG NO. 1083-09-05 | REV B
SCALE: 1"=1'-0" & NOTED | RELEASE DATE | SH 1 OF 1

REVISIONS				
ZONE	LTR	DESCRIPTION	APPROVED	
	A	ORIGINAL ISSUE		
	B	G01 WAS "COLUMN WELDMENT", ITEM 3 WAS SPACER; ADDED OPTIONAL MAT'L TO IT. 1, THE 1.750 DIM WAS 1.500 ON IT. 3. IN NOTE 3 JCP&L SPEC WAS MPR SPEC 89-09-02 ADDED IT. 6. ADDED IT. 7	K WHITE 6/6/79 / J. Abrino 6-8-79	J. Johnson 6-8-79 / W. Sylk 6-8-79



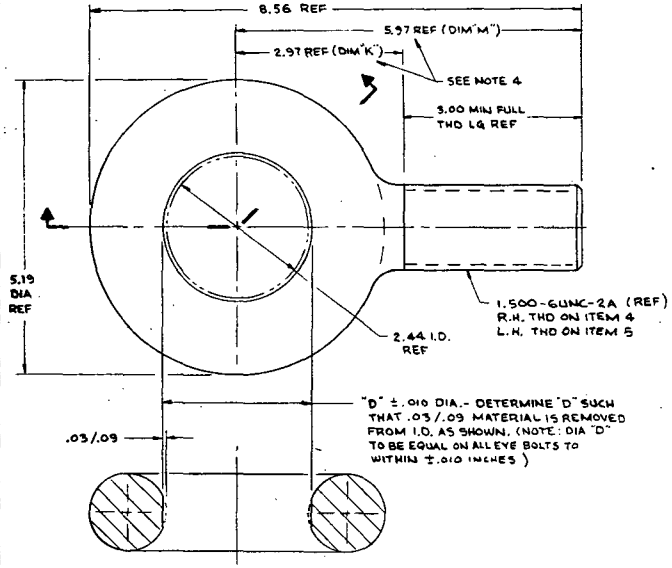
G01 STRUT WELDMENT
SCALE: FULL

NOTES:

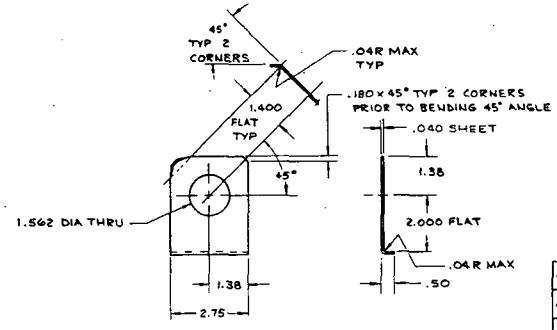
1. INTERPRET DWG PER ANSI Y14 WITH DIMENSIONING & TOLERANCING PER ANSI Y14.5.
2. UNLESS OTHERWISE SPECIFIED:
   - EDGES – .01 TO .03 RADIUS OR CHAM
   - MACHINE SURFACES – 250
   - STOCK SURFACES – 250
3. MANUFACTURE, INSPECT, & CLEAN PER JCP&L SPEC 125.3-1
4. PRIOR TO FABRICATING G01 TO THE 46.06 LENGTH (DIM "L"), CONFIRM THE 15.25 CLAMP DIM (DIM "H") SHOWN AT PLAN VIEW A ON DWG 1083-09-05 AND THE 2.97 (DIM "K") & 5.97 (DIM "M") EYE BOLT DIM'S. IF ANY OF THESE DIM VARY BY MORE THAN .25 INCHES, RECALCULATE NEW LENGTH "L" AS FOLLOWS:

   L = 85.50 - 2H - K - M

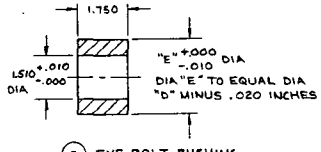
   (USE MAX "K" & MIN "M" DIM OF ALL EYE BOLTS)
5. BRACE ASSEMBLY "D" (SEE DWG 1083-09-05) TOTAL AXIAL ADJUSTMENT IS ± 1.50 INCHES BASED ON THE 3.00 MIN FULL THD LENGTH OF EYE BOLT.



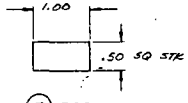
4 EYE BOLT (R.H. THD)
5 EYE BOLT (L.H. THD)
SCALE: FULL
NOTE: REF DIM'S ARE PER ASTM A489, TYPE 1



6 LOCKING TAB
SCALE: 1/2



3 EYE BOLT BUSHING
SCALE: 1/2



7 BAR
SCALE: FULL

TOTAL QTY REQ'D ON NEXT ASS'Y, DWG 1083-09-05 (REF)

QTY REQD					PART NO.	DESCRIPTION	MATERIAL / SPECIFICATION	ITEM NO.
480						BAR, .50 SQ STK	ASME SA 36	7
480						LOCKING TAB	SST TYPE 304, ANNEALED	6
60						EYE BOLT, PLAIN, 1.500-6UNC-2A, L.H. THD.	CLEVELAND CITY FORGE CO. CLEVELAND, OH. (OR EQUAL.)	5
60						EYE BOLT, PLAIN, 1.500-6UNC-2A, R.H. THD	(MACHINE I.D. AS SHOWN ON THIS DWG)	4
120						EYE BOLT BUSHING	ASME SA 36	3
	2					BAR, 2.875 DIA STK	ASME SA 36	2
	1					PIPE, 2.50 SCH 40	ASME SA 106 GR B, SA333 GR6 OR SA53 GR. B	1
60	X					STRUT WELDMENT	———	G01

G01 QTY REQD | SYM | CODE IDENT NUMBER | PART NO. | DESCRIPTION | MATERIAL / SPECIFICATION | ITEM NO.
SYM: V = VENDOR ITEM
PARTS LIST

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES.
TOLERANCES

2 PLACE	3 PLACE	ANGLES
± .06	± .030	± 2°

DO NOT SCALE.
NEXT ASSEMBLY 1083-09-05

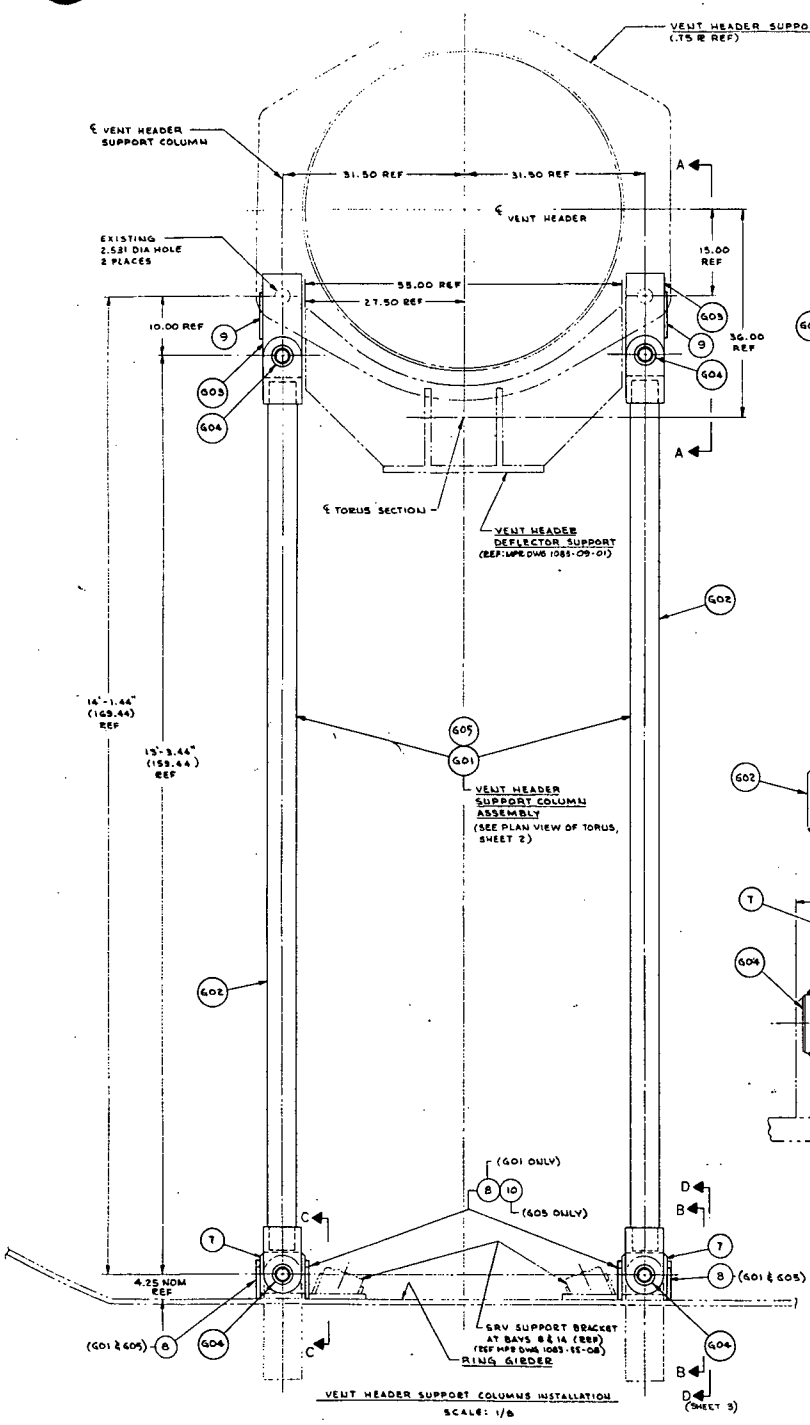
CONTRACT NUMBER	———	
DRAFTSMAN	CAP	DATE 9-30-78
CHECKER	J. Abrino	DATE 11-21-78
HEAD OF DESIGN	W. Sylk	DATE 11-22-78
ENGINEER	John Johnson	DATE 11-22-78

MPR ASSOCIATES, INC.
1140 CONNECTICUT AVE, N.W. WASHINGTON, D.C. 20036
TITLE OYSTER CREEK GENERATING STATION
TORUS DOWNCOMER LATERAL SUPPORT SYSTEMS
DETAILS

SIZE	CODE IDENT NO.	DWG NO.	REV
D	———	1083-09-06	B

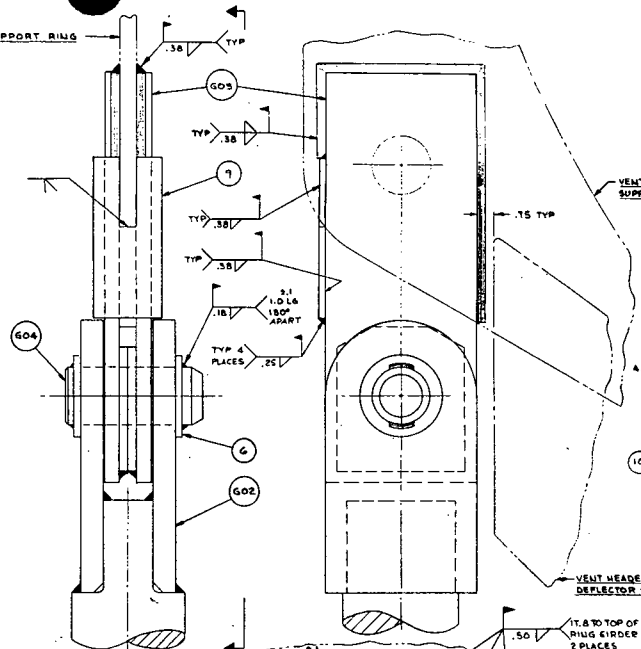
SCALE: NOTED

1083-09-06



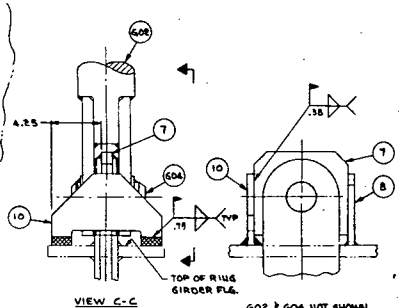
VENT HEADER SUPPORT COLUMNS INSTALLATION

SCALE: 1/8



VIEW A-A

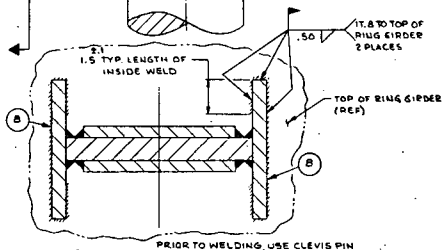
SCALE: 1/2

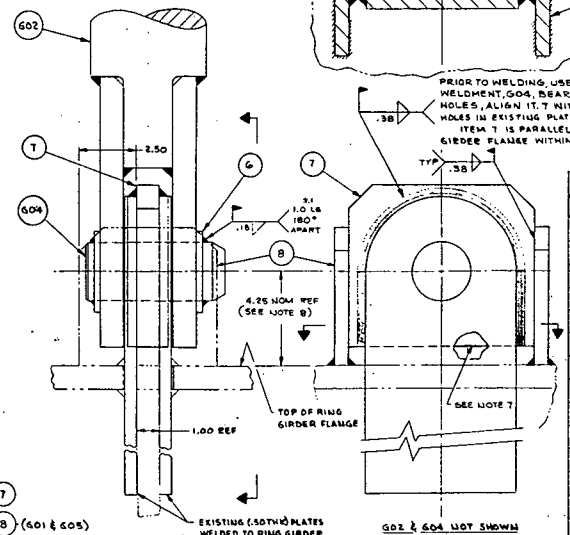


VIEW C-C

SCALE: 1/4 (AT G05 ONLY)

G02 & G04 NOT SHOWN





VIEW B-B

SCALE: 1/2 (G01 SHOWN)

G02 & G04 NOT SHOWN

PRIOR TO WELDING, USE CLEVIS PIN WELDMENT, G04, BEARING AT TOP OF HOLES, ALIGN IT. 7 WITH HOLES IN EXISTING PLATES SUCH THAT ITEM 7 IS PARALLEL TO TOP OF RING GIRDER FLANGE WITHIN .125

NOTES:

1. INTERPRET DRAWING PER ANSI Y14 WITH DIMENSIONING AND TOLERANCING PER ANSI Y14.5.
2. UNLESS OTHERWISE SPECIFIED:
   - EDGES .01 TO .03 RADIUS OR CHAMFER
   - MACHINED SURFACES 250/ PER ANSI B46.1
   - STOCK SURFACES AS PURCHASED
3. MANUFACTURE, INSPECT AND PAINT IN ACCORDANCE WITH JCP&L/GPU PROCUREMENT SPEC 125.18-1.
4. INSTALL PER JCP&L/GPU INSTALLATION SPEC QC-15-602319-001.
5. INTERPRET WELD SIZES AS FOLLOWS:
   $.18 = \frac{3}{16}$ $.31 = \frac{5}{16}$ $.38 = \frac{3}{8}$
6. WELD SIZES ARE TO BE INTERPRETED AS MINIMUM SIZES. TOLERANCING DOES NOT APPLY TO WELDS.
7. ITEM 7 IS TO BE FIELD CUT FOR FITUP. THE MAXIMUM PERMISSIBLE GAP BETWEEN THE BOTTOM OF ITEM 7 AND THE TOP OF THE RING GIRDER FLANGE IS DETERMINED AS FOLLOWS. WHERE THE DISTANCE FROM THE CENTERLINE OF THE BOTTOM PIN TO THE TOP OF RING GIRDER FLANGE IS 3.25 INCHES OR GREATER, THE MAXIMUM PERMISSIBLE GAP IS 1.50 INCHES. WHERE PIN-TO-FLANGE DIMENSION IS LESS THAN 3.25 INCHES, THE MAXIMUM PERMISSIBLE GAP IS DETERMINED BY SUBTRACTING 1.75 INCHES FROM THE PIN-TO-FLANGE DIMENSION.

NOTES CONTINUED ON SHEET 3

G05	G04	G03	G02	G01	QTY REQD	CODE IDENT NUMBER	PART NO.	DESCRIPTION	MATERIAL / SPECIFICATION	ITEM NO.
				AR				REINFORCING PAD 1.00 THK STK	ASME SA 516 GR. 70	11
X								VENT HEADER SUPPORT COLUMN ASSEMBLY - MOD.	—	G05
1								GUSSET PLATE .625 THK STK	ASME SA 516 GR. 70	10
1				1				TIE PLATE, .25 THK STK	ASME SA 516 GR. 70	9
1				2				GUSSET PLATE, .625 THK STK	ASME SA 516 GR. 70	8
1				1				RING GIRDER, TONGUE PLATE, 1.00 THK STK	ASME SA 516 GR. 70	7
2	1			2				PLATE, .25 THK STK	ASME SA 36	6
	1							BAR, 2.50 DIA STK	ASME SA 36	5
		1						PLATE, .75 THK STK	ASME SA 516 GR. 70	4
		2						PLATE, .625 THK STK	ASME SA 516 GR. 70	3
			4					PLATE, 1.00 THK STK	ASME SA 516 GR. 70	2
			1					BAR, 5.00 DIA STK	ASME SA 36	1
2	X			2				CLEVIS PIN WELDMENT	—	G04
1		X		1				RING COLLAR ATTACHMENT WELDMENT	—	G03
1			X	1				COLUMN WELDMENT	—	G02
				X				VENT HEADER SUPPORT COLUMN ASSEMBLY - MOD	—	G01

PARTS LIST

QTY REQD: STOCK V = VENDOR ITEM

QUANTITIES LISTED FOR G01 & G05 ARE REQUIRED TO MAKE A SINGLE SUPPORT COLUMN ASSEMBLY. FOUR SUPPORT COLUMN ASSEMBLIES ARE REQUIRED AT EACH OF THE TEN NON-VENT BAYS FOR A TOTAL OF 40 ASSEMBLIES. TWO G05 AND TWO G01 ASSEMBLIES ARE REQUIRED AT BAYS 8 & 14 AND FOUR G01 ASSEMBLIES AT ALL OTHER NON-VENT BAYS. SEE PLAN VIEW OF TORUS ON SHEET 2 FOR LOCATION OF G05 ASSEMBLIES.

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES.

TOLERANCES		
2 PLACE	3 PLACE	ANGLES
±.06	±.030	± 1°

DO NOT SCALE.

NEXT ASSEMBLY

CONTRACT NUMBER

DRAFTSMAN: L. Alexiunas — DATE 8-19-81

CHECKER: J.E. Bryant — DATE 8-11-81

HEAD OF DESIGN: M. Sofo — DATE 8-11-81

ENGINEER: T. Tsao — DATE 8-11-81

MPR ASSOCIATES, INC.

1140 CONNECTICUT AVE., N.W. WASHINGTON, D.C. 20036

TITLE: OYSTER CREEK GENERATING STATION
VENT HEADER REPLACEMENT SUPPORT COLUMNS
FABRICATION AND INSTALLATION

SIZE: E — CODE IDENT NO. — DWG NO. 1083-09-07 — REV D

SCALE: AS NOTED — RELEASE DATE 8-13-81 — SH 1 OF 3

ZONE	LTR	DESCRIPTION	APPROVAL
	A	ORIGINAL ISSUE	
	B	AT ZONE D-3, ADDED SECTION SHOWING .50 FIELD WELD OF IT. 8 TO RING GIRDER; ADDED NOTES 5, 6 & 7; DELETED .38 WELD OF IT. 8 TO RING GIRDER	11-17-81 11-24-81 11-24-81
	C	ADDED; G05, ITEM 10 AND VIEW C-C. REVISED QUANTITIES NOTE	8-6-82 8-6-82 8-6-82
	D	ADDED SHEET 3; ADDED SECT. D-D AND ITEM 11; MODIFIED NOTES 5 & 7; DELETED ONE(1) .38 WELD FROM VIEW B-B & C-C	7-17-83 7-14-83 7-14-83

Oyster Creek Document Distribution Sheet

TITLE/SUBJECT: **Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell Associated with AmerGen's License Renewal Application (TAC No. MC7624)**

COGNIZANT INDIVIDUAL: **Fred Polaski**

SPECIAL HANDLING INSTRUCTIONS:
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Plant Systems Engineering: S. Hutchins	OC	E
Lic. Renewal: T. E. Quintenz	OC	E
Chem/Env Dept Files	AOB	
Reg Assurance Dept Files	**05040**	E

Other

K. Barnes	OCAB-2	E
C. Duffy	OCAB-2	E
P. Tamburro	OCAB	E
B. Barbieri	OCAB	E

STANDARD RECORDS RETENTION SCHEDULE #	FILE CODE / (REFERENCE #)	RECORD NUMBER	RECORD NAME	RECORD DATE
	05040	2130-06-20360	Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell Associated with AmerGen's License Renewal Application (TAC No. MC7624)	7/7/06

Specification
IS-328227-004

Specification
for
Oyster Creek

Function Requirements for Drywell Containment Vessel Thickness Examinations

Preparation: Peter Tamburro 9/15/06

Reviewed By: Charles Schilling 9/15/06

Engineering Approval: Howie Ray by Thomas Ruggiero 9/15/06

Revision 13

	DOCUMENT NO.
	IS-328227-004

TITLE Functional Requirements For Drywell Containment Vessel Thickness Examinations

REV	SUMMARY OF CHANGE	APPROVAL	DATE
13	A complete revision resulting from commitments to the NRC for Oyster Creek Licensing Renewal life extension from 2009 to 2029. . Revision 13 now provides requirements for the following: 1. UT Examinations at selected locations on the inside of the Drywell at elevation 51' 2"; 51''10"; 60'10" and 87' 5". These inspection were previously performed on a 4 year interval. However new acceptance criteria has been established for entering results into the Corrective Action System. 2. Visual coating inspections of the coating applied on the Drywell Vessel in 1992 in the former sandbed region. These inspections were previously performed on a 4 year interval. However new acceptance criteria has been established for entering results into the Corrective Action System. In addition the inspection reflects addition commitments to perform a complete 100% inspection of all bays by 2009 and a complete 100% during the period of extended operation between 2009 and 2029. 3. UT Examinations at selected locations on the inside of the Drywell at elevation 11' 3" (the former sandbed region). These inspections were previously performed in various intervals until 1996 at time which GPUN received approval from the NRC discontinue the inspections. However new licensing renewal commitments have been made to perform a complete 100% inspection of all bays by 2009 and an additional complete 100% inspection during the period of extended operation between 2009 and 2029. Also, acceptance criteria has been established for entering results into the Corrective Action System. 4. External Inspection and UT Examinations of 16 locally thin areas in Bays 1 and 13. This is a new licensing renewal commitment which is a one time inspection to be performed prior to the 2009. 5. Inspection of the five sandbed drains to ensure these lines are not clogged. This is not a commitment. However it is considered prudent measure to ensure the drain lines are not clogged. 6. UT Examination and visual inspection of the drywell shell within the two trenches inside the drywell on concrete floor (El. 10'-3") in bays 5 and 17. This is a new licensing renewal commitment that shall be performed once prior to the 2009.	Preparer - Peter Tamburro PATL Reviewer – Charles Schilling Charles Schilling Manager - Howie Ray	7/15/06 7/15/06

	7. UT Examination of a welds at Elevation 23' 6". This is a new licensing renewal commitment, which shall be performed once prior to the 2009 and once during the period of extended operation. 8. UT Examination of a weld at Elevation and 71'6". This is a new licensing renewal commitment, which shall be performed once prior to the 2009 and once during the period of extended operation.		

1.0 Scope

This specification establishes requirements for Non Destructive Examination (NDE) of the Oyster Creek Drywell Containment Vessel. This specification has been revised due to Licensing Renewal Commitments in reference 2.19. The following inspections and examinations are addressed:

1) UT (Ultrasonic Thickness) Examinations at selected locations on the inside of the Drywell at elevation 51' 2"; 51' 10"; 60'10" and 87' 5". The purpose of these examinations is to monitor long term corrosion rates at these elevations.

2) Visual coating inspections (VT-1) of the coating applied on the Drywell Vessel exterior in 1992 in the former sandbed region. The purpose of these inspections is to ensure that the condition of the coating is acceptable and meets Section XI, Subsection IWE requirements. These inspections are required to meet Oyster Creek License Renewal commitments.

3) UT Examinations at selected locations inside the Drywell at elevation 11' 3" (the former sandbed region). The purpose of these examinations is to verify that the external coating is effectively protecting the drywell vessel and that external corrosion is insignificant. These inspections are required to meet Oyster Creek License Renewal commitments.

4) External UT Examinations of locally thin areas in Bays 1 and 13. The purpose of these examinations is to attempt to locate and measure locally thin areas that were identified during external inspections in 1992. These inspections are required to meet Oyster Creek License Renewal commitments. These UT inspections will be performed through existing coating.

5) Inspect the sandbed drains to ensure these lines are not clogged. These inspections will ensure that the sandbed drains are not clogged and water will not collect in the former sandbed region and challenge the coating.

6) UT Examination and visual inspection of the drywell shell within the two trenches inside the drywell on concrete floor (El. 10'-3") in bays 5 and 17. The purpose of these examinations is to verify that the internal coating in the trenches is effectively protecting the drywell vessel and that external corrosion is insignificant. These inspections are required to meet Oyster Creek License Renewal commitments.

7) UT Examination of the weld joint at Elevation 23' 6 7/8". The purpose of this examination is to provide an indication that the drywell vessel at this weld has not significantly degraded. This inspection is required to meet Oyster Creek License Renewal commitments. This UT inspection will be performed through existing internal coating.

8) UT Examination of the weld joint at Elevation 71' 6". The purpose of this examination is to provide an indication that the drywell vessel at this weld has not significantly degraded. This inspection is required to meet Oyster Creek License Renewal commitments. This UT inspection will be performed through existing coating.

2.0 Reference

Unless otherwise noted, the latest revision applies.

2.1 ASME B&PV Code Section V, 1986 Edition

2.2 ASME B&PV Code Section XI, Subsection IWE, 1992 Edition

2.3 C-1302-187-E310-030 Revision 1, "Statistical Analysis of Drywell Thickness Through September 1996"

2.4 TQ-AA-122, "Qualification And Certification of Nondestructive (NDE) Personnel"

2.5 ER-AA-335-004, "Manual Ultrasonic Measurements of Material Thickness and Interfering Conditions"

2.6 GPUN Sketch, No. SK-S-89

2.7 GPUN Sketch, No. SK-S- 85

2.8 C-1302-187-E310-037 Revision 2, "Statistical Analysis of Drywell Vessel Thickness Data"

2.9 C-1302-187-5320-024, Revision 1, "Drywell External Ultrasonic Testing Evaluation in Sandbed"

2.10 GPUN Drawing 3E-187-29-001, Revision 0, Drywell Shell Stretch-out".

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

2.12 OCIS-328227-003,"Repair of Concrete Floor Removed in Drywell For UT Readings"

2.13 NRC SER date November 1, 1995 – Changes in the Oyster Creek Drywell Monitoring Program

2.14 ECR 05-00275, Drywell Vessel inspections through 2004.

2.15 License Renewal Commitment Letter –from M.P. Gallagher to NRC dated April 4, 2006 (2130-06-20284)

2.16 ER-OC-330-1006, "First 10 Year Containment (IWE) Inservice Inspection Program Plan and Basis, Draft.

2.17 PBD-AMP-B.1.27, Program Basis Document ASME Section XI, Subsection IWE.

2.18 ER-AA-335-030, "ULTRASONIC EXAMINATION OF FERRITIC PIPING WELDS"

2.19 Commitments

- **CM-1** PASSPORT AR 00330592.27, Oyster Creek Licensing Renewal Commitments Associated with Aging Management Program B.1.27, ASME Section XI, Subsection IWE (Steps 1.0)

- **CM-2** PASSPORT AR 00330592.33, Oyster Creek Licensing Renewal Commitments Associated with Aging Management Program B.1.33, Protective Coating Monitoring and Maintenance Program

3 Requirements

3.1 Non Destructive Examinations

3.1.1 Personnel Qualification

3.1.1.1 Personnel conducting Ultrasonic Examinations shall be qualified in accordance with ER-AA-335-004.

3.1.1.2 Personnel conducting Visual Examinations shall be VT-1 qualified in accordance with ER-AA-335-018.

3.1.2 Examination Procedures

3.1.2.1 NDE UT examinations shall be performed in accordance with ER-AA-335-004 and this specification.

3.1.2.2 Visual Examination of the Drywell Vessel coating on the exterior surface of the former sandbed region and the internal portions of the trenches shall be performed in accordance with ER-AA-335-018.

3.1.2.3 NDE UT examinations of welds (in section 3.2.7 and 3.2.8) shall be performed in accordance with ER-AA-335-030 and this specification.

3.1.3 Methodology and Equipment

The UT examinations performed inside the Drywell shall be performed by one of the following methods:

3.1.3.1 Forty Nine Point Examinations

3.1.3.1.1 For these locations the inspector shall use a stainless steel template fabricated in accordance with Exhibit 2.

3.1.3.1.2 Prior to inspection remove the existing grease that has been previously applied on the area for corrosion protection.

3.1.3.1.3 At each location, the template shall be placed on the drywell vessel so that the notches on the template line up with the low stress die stamps that have been previously stamped on the surface of the drywell. The Inspector shall use a

UT transducer that fits within the template within a clearance of 1/16".

3.1.3.1.4 The UT transducer shall be positioned in the same orientation at each grid point. (I.e. the top of the transducer is always positioned to the top template).

3.1.3.1.5 After the UT inspection coat the location with Versilube G351 grease or an approved alternative.

3.1.3.2 Seven Point Examinations

3.1.3.2.1 For these locations the inspector shall use the same stainless steel template fabricated in accordance with Exhibit 2.

3.1.3.2.2 Prior to inspection remove the existing the grease that has been previously applied on the area for corrosion protection.

3.1.3.2.3 At each location, the template shall be placed on the drywell vessel so that the notches on the template line up with the low stress die stamps that have been previously stamped on the surface of the drywell. The Inspector shall use a UT transducer that fits within the template within a clearance of 1/16". The inspector shall record only the 7 readings in the middle row.

3.1.3.2.4 The UT transducer shall be positioned in the same orientation at each grid point. (I.e. the top of the transducer is always positioned to the top of the template).

3.1.3.2.5 Use of the template, the UT transducer, and aligning it with the template notches to the stamp on the Drywell ensures that each individual reading is located within a 1/8" of previous readings.

3.1.3.2.6 After the UT inspection coat the location with Versilube G351 grease or an approved alternative.

3.1.3.3 Multiple Point Examinations within the two floor Trenches

3.1.3.3.1 For these two locations the inspector shall use the same stainless steel template fabricated in accordance with Exhibit 2.

3.1.3.3.2 Refer to Exhibit 5. Within each trench, place the template at the very bottom of the trench and record the data. After the 49 points are recorded, relocate the template up the trench as shown in Exhibit 5. Ensure the centerline of the bottom row on the relocated template is 1" +/ - 1/16" from the previous grid top row. The inspector shall use a UT transducer that fits within the template within a clearance of 1/16".

3.1.3.3.3 The UT transducer shall be positioned in the same orientation at each grid point. (I.e. the top of the transducer is always positioned to the top of the template). The UT readings shall be taken through the existing coating.

3.1.3.4 Core Bore Locations

The following specific location/grid points have core bore plugs.

Bay Area	Points
11A	23, 24, 30, 31
17D	15, 16, 22, 23
19A	24, 25, 31, 32
19C	20, 26, 27, 33
5/D12 (51-D1)	20, 26, 27, 28, 33, 34, 35

3.1.4 Inspection Schedule

All inspections required by this specification shall be performed during the scheduled Refueling Outage for the years shown in the table 4.

3.2 Inspections

3.2.1 Internal UT Inspection of Upper Elevations

A total of nine locations are monitored for corrosion rates at elevation 51' 2"; 51' 10"; 60' 10" and 87' 5". Forty-nine individual UT readings shall be recorded at each of the nine locations in accordance with section 3.1.3.1. Table 1 below provides information for each of these locations.

Table 1 – Upper Elevation Inspection Location

Location ID	Bay	Elevation	Original NDE Data sheet	Minimum Acceptance Criteria for each Individual Reading
5/D12 (51-D1)	5	50' 2"	87-026-26	0.620"
5-5 (51-5)	5	50' 2"	87-026-124	0.620"
13/31 (51-13)	13	50' 2"	87-026-126	0.620"
15/23 (51-15)	15	50' 2"	87-026-123	0.620"
13/31 (52-13)	13	51'10"	87-026-144	0.675"
50-22	1	60' 10"	DWCV-R-005	0.625"
9/20 (86-20)	9	87' 5"	87-026-30	0.545"
13/28 (86-28)	13	87' 5"	87-026-37	0.545"
15/31 (86-31)	15	87' 5"	87-026-38	0.545"

3.2.1.1 Acceptance Criteria

With the exception of individual points positioned over core plugs (as documented is section 3.1.3.4) each individual reading less than the minimum value specified in the table 1 shall be entered into the corrective action program and evaluated by Engineering.
The acceptance criteria in table 1 is based on the minimum recorded readings in 2004 (reference 2.8) and a 20 mil tolerance. The acceptance criteria is not based on the minimum required code thickness, which is less than the above values.

3.2.1.2 Data Retention

All 49 readings values at each location shall be documented on an NDE data sheet and formatted in a 7 by 7 matrix, which

corresponds to the template. The data sheet shall also include: the date and time of the examination, location of core plugs (if applicable), the examination method, the ID number of the equipment, the ID number of the cal block, the location surface temperature, Examiner, Reviewer, the governing procedure, Location ID in accordance with Table 1. Forward the completed data sheets to Engineering.

3.2.1.3 Required Support and Tools

3.2.1.3.1 In order to provide access to the three inspection locations at elevation 87' 5", temporary planking shall be provided as necessary at the top of the biological shield extending to the drywell wall.

3.2.1.3.2 Safety and Radcon support and coverage shall be provided as necessary.

3.2.1.3.3 Prior to the UT inspection of each location remove the existing grease that was applied after the last inspection shall be removed.

3.2.1.3.4 After the UT inspection coat the location with Versilube G351 grease or an approved alternative.

3.2.2 Internal UT Inspection of Former Sandbed Region Elevations

3.2.2.1 Description

A total of 19 locations are monitored for corrosion rates at elevation 11' 3". Individual UT readings shall be recorded at each location in accordance with section 3.1.3.1 and 3.1.3.2. Table 2 below provides information for each of these locations.

Table 2– Sandbed Elevation Inspection Location

Location ID	No of points	Bay	Elevation	Original NDE Data sheet	Average Thickness based on 1992 Inspections (inches)	Average Thickness based on 1994 Inspections (inches)	Average Thickness based on 1996 Inspections (inches)
9D	49	9	11' 3"	87-026-59	0.996	0.987	1.008.
11A	49	11	11' 3"	87-049-24	0.842	0.820	0.83
11C	49	11	11' 3"	87-049-37	0.937	0.895	0.951
13A	49	13	11' 3"	87-026-58	0.865	0.837	0.843
13D	49	13	11' 3"	87-026-67	1.001	0.959	0.99
15D	49	15	11' 3"	87-026-58	1.065	1.053	1.066
17A	49	17	11' 3"	87-026-58	1.024	1.017	1.050
17D	49	17	11' 3"	87-049-26	0.823	0.81	0.845
17/19	49	17	11' 3"	87-026-66	0.982	0.97	0.980
19A	49	19	11' 3"	87-049-27	0.809	0.806	0.815
19B	49	19	11' 3"	87-049-28	0.847	0.824	0.837
19C	49	19	11' 3"	87-049-29	0.832	0.82	0.848
1D	7	1	11' 3"	87-026-54		1.07	1.074
3D	7	3	11' 3"	87-026-55		1.184	1.181
5D	7	5	11' 3"	87-026-56		1.168	1.173
7D	7	7	11' 3"	87-026-57		1.136	1.138
9A	7	9	11' 3"	87-026-60		1.157	1.155
13C	7	13	11' 3"	87-026-61		1.14	1.154
15A	7	15	11' 3"	87-026-62		1.114	1.127

3.2.2.2 Acceptance Criteria

3.2.2.2.1 With the exception of individual points positioned over core plugs each of the 49 individual readings less than 0.628" shall be entered into the corrective action program and

evaluated by Engineering. This acceptance criteria is based on the minimum recorded readings in 1994 (reference 2.3) and a 20 mil tolerance. Acceptance criteria is not based on the minimum required code thickness, which is less than 0.628".

3.2.2.2.2 In addition Engineering shall calculate the average value of each location consistent with reference 2.3. The calculated average for each location shall be within +/- 0.020" of the values documented in table 2. Values not within +/- 0.020" shall be entered into the corrective action program and evaluated by Engineering and shall be subject to the following actions:

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

3.2.2.3 Data Retention

Values at each location shall be documented on an NDE data sheet and formatted in a either 7 by 7 or a 1 by 7 matrix, which corresponds to the template. The data sheet shall also include: the date and time of the examination, location of the core plugs, the examination method, the ID number of the equipment, the governing procedure, the ID number of the cal block, the location surface temperature, Examiner, Reviewer, Location ID in accordance with table 2. Forward the completed data sheets to Engineering.

3.2.2.4 Required Support and Tools

3.2.2.4.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.2.4.2 Prior to the UT inspection of each location remove the existing grease (with an approved cleaner), which was previously applied after the last inspection.

3.2.2.4.3 After the UT inspection coat the location with Versilube G351 grease or an approved alternative.

3.2.3 External UT Inspection of Locally Thin Areas in Bays 1 and 13

3.2.3.1 Description

3.2.3.1.1 Locate and perform UT Inspection of 16 locally thin areas found during the external inspection of the Drywell in 1992, These areas were identified in NDE data sheets 92-072-01 through 92-072-26. Perform the UT inspection through the coating. Select UT equipment that is capable of subtracting the coating thickness from the vessel wall thickness.

3.2.3.1.2 The inspections shall capture the size of each area for all areas thinner than 0.736". Characterize the thicknesses within this area by recording the top, bottom, left, right, center and minimum thickness.

3.2.3.1.3 Table 3 below provides information for each of these locations. Locations are based on the distance from the vertical weld at the centerline of the vent line (horizontal) and the vent line penetration weld at the centerline (vertical). See NDE data sheet 92-072-01 and 02.

Table 3 - External Inspection Locations

Bay	Point Number	Vertical Location	Horizontal Location	Measured Lowest Thickness In 1992 Inches	Reference
1	1	Down 16"	Right 30"	0.720	92-072-12
	2	Down 22"	Right 17"	0.716	92-072-12
	3	Down 23"	Left 3"	0.705	92-072-12
	5	Down 24"	Left 45"	0.710	92-072-12
	7	Down 39"	Right 5"	0.700	92-072-12
	11	Down 23"	Right 12"	0.714	92-072-18
	12	Down 24"	Left 5"	0.724	92-072-18
13	1	Up 1"	Right 45"	0.672	92-072-24
	2	Up 1"	Right 38"	0.729	92-072-24
	5	Down 21"	Right 6"	0.718	92-072-24
	6	Down 24"	Left 8"	0.655	92-072-24
	7	Down 17"	Left 23"	0.618	92-072-24

Table 3 - External Inspection Locations					
Bay	**Point Number**	**Vertical Location**	**Horizontal Location**	**Measured Lowest Thickness In 1992 Inches**	**Reference**
	8	Down 24"	Left 20"	0.718	92-072-24
	10	Down 28	Right 12"	0.728	92-072-24
	11	Down 28"	Left 15"	0.685	92-072-24
	15	Down 20"	Left 9"	0.683	92-072-24

3.2.3.2 Acceptance Criteria

Readings less than 0.598" shall be entered into the corrective action program and evaluated by Engineering. This acceptance criteria is based on the minimum recorded reading in 1992 (reference 2.9) and a 20 mil tolerance. Acceptance criteria is not based on the minimum required code thickness, which is less than the above value.

3.2.3.3 Data Retention

All readings and areas sizes for each location shall be documented on an NDE data sheet. The data sheet shall also include: the date and time of the examination, the examination method, the ID number of the equipment, the governing procedure, the ID number of the cal block, the location surface temperature, Examiner, Reviewer, Location ID in accordance with Table 3. Forward the completed data sheets to Engineering.

3.2.3.4 Required Support and Tools

3.2.3.4.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.3.4.2 The cavity in the former sandbed region is a confined space.

3.2.3.4.3 To provide access to the cavity in the former sandbed region, the station must erect scaffolding up to each man way in the Drywell Pedestal located in the Torus Room.

3.2.3.4.4 The station shall also remove the boron bags that fill man way.

3.2.3.4.5 After Inspections per sections 3.2.3 and 3.2.4 are completed the station shall reinstall the boron bags in each man way.

3.2.3.4.6 Remove the scaffolding.

3.2.4 External Visual Inspection of the Sandbed Coating

3.2.4.1 Description

3.2.4.1.1 The external coating that was applied in 1992 to the Drywell Vessel shall be inspected in accordance with ER-AA-335-018 and ASME Section XI subsection IWE.

3.2.4.1.2 Inspect exterior surfaces of the drywell for water and the concrete floor for ponding or standing water.

3.2.4.1.3 The entire surface from the base of the sand bed region concrete floor (El 8' 11") to the top where the vessel rises into the 3" gap with the concrete (El. 12' 3") shall visually (VT-1) be inspected. In the horizontal direction the inspection of one bay shall constitute all surfaces within 16 feet centered on the vent line (see Exhibit 3).

3.2.4.1.4 The inspection shall include a visual inspection of the caulking that was applied in 1992 at the interface between the former sandbed concrete floor and the drywell vessel (see Exhibit 4).

3.2.4.1.5 Video equipment or photographs shall be used to document the general condition of the coating. However, the resulting videos and photos shall be informational only. The actual inspection shall be direct visual and performed per ER-AA-335-018

3.2.4.2 Acceptance Criteria

3.2.4.2.1 Refer to Attachment 2 of procedure ER-AA-335-018. All surface areas with flaking, chipping, blistering, peeling, pinpoint rusting, cracking, chalking and discoloration attributable to rust blooms shall be entered into the Corrective Action Program and evaluated by Engineering.

3.2.4.2.2 The caulking at the base of the Drywell shall be free of chipping, peeling, and cracking. Deviation shall be entered into the Corrective Action Program and evaluated by Engineering.

3.2.4.2.3 Discoloration due to loose surface residue from surface wetting is acceptable so long as the coating below the residue has not degraded.

3.2.4.2.4 Minor flaking, chipping and peeling is acceptable. Minor flaking, chipping and peeling is defined as follows: isolated flaking, chipping and peeling where: the loose coating is less than a ¼ square inch, is on the surface of the coating or caulking and does not penetrate to the base metal. The purpose of this exception is to allow minor physical damage that may have been caused by personnel moving around in the sand bed region and is not indicative of a coating or caulking breakdown.

3.2.4.2.5 Documentation of degraded areas shall include the location of the area (i.e. X inches from the vertical weld and Y inches from the downcomer penetration weld), the size of the area, and the specific degradation. A color picture of degraded areas shall be taken and provided to Engineering.

3.2.4.2.6 Document bays where ponding or standing water was observed.

3.2.4.3 Data Retention

Inspections shall be documented for each bay on an NDE data sheet. The data sheets shall also include: the date and time of the examination, the examination method, the governing procedure, Examiner, and Reviewer.

3.2.4.4 Required Support and Tools

3.2.4.4.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.4.4.2 The cavity in the former sandbed region is a confined space.

3.2.4.4.3 To provide access to the cavity in the former sandbed region, the scaffolding contractor must erect scaffolding up to each 20" man way in the Drywell Pedestal located in the Torus Room.

3.2.4.4.4 The field shall also remove the boron bags that fill each 20" man way.

3.2.4.4.5 After Inspections per section 3.2.3 and 3.2.4 are completed the station shall reinstall the boron bags and fill up each 20" man way and remove the scaffolding.

3.2.5 Sandbed Drain Line Inspection

3.2.5.1 Description

3.2.5.1.1 The former Sandbed cavity has five drain lines equally spaced around the sandbed (see exhibit 4). The purpose of these drains is to drain the cavity should water be introduced into the former sand bed cavity. The drains exit the Drywell Pedestal at the base of the Pedestal in the Torus Room.

3.2.5.1.2 Inspect these drains with a boroscope type video system to ensure they are not clogged. Inspections for each of the 5 specific drains shall be scheduled in the same refueling outage corresponding to the visual coating inspections (section 3.2.4); see table 4.

3.2.5.2 Acceptance Criteria

Each drain line shall be free of blockage. Minor amounts of blockage (less than 15% of the cross sectional area) are acceptable. Lines with unacceptable blockage shall be entered in to the Corrective Action Program.

3.2.5.3 Data Retention

Inspections shall be documented for each line on an NDE data sheet or in the PIMS Work Order including blockage less than 15%. The data sheets or PIMS Work Order shall also include: the date and time of the examination, the examination method, the governing procedure, Examiner, and Reviewer.

3.2.5.4 Required Support and Tools

3.2.5.4.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.5.4.2 The cavity in the former sandbed region is a confined space.

3.2.6 Trench Visual and UT Examination

3.2.6.1 Description

3.2.6.1.1 In the mid 1980's two trenches were cut out of the Drywell floor at elevation 10' 3". The purpose of these trenches was to allow UT inspection of the Drywell Vessel below the removed concrete. The inspection results were captured on NDE data sheets 86-049-047 and 86-049-056 (reference 2.7). These trenches were then filled by the installation of a foam material (reference 2.11).

3.2.6.1.2 The base Drywell Vessel metal at the bottom of these two trenches shall be inspected as follows:

1) Care shall be taken not to damage the coating under the foam. Once the foam has been removed by an approved work order inspect the coating applied to the Vessel in accordance with ER-AA-335-018 and ASME Section XI subsection IWE. Video equipment or photographs shall used to document the general condition of the coating. However, the resulting videos or photos shall be informational only. The actual inspection shall be direct visual and performed per ER-AA-335-018.

2) If the coating does not require repair, then perform UT inspection of the vessel through the coating per section 3.1.3.3. Select UT equipment that is capable of subtracting the coating thickness from the vessel wall thickness.

3) If the coating does require repair, then perform UT inspection of the vessel per section 3.1.3.3 once the coating has been removed for repair.

3.2.6.2 Acceptance Criteria

3.2.6.2.1 Visual Inspection Acceptance Criteria

3.2.6.2.1.1 Refer to in attachment 2 of procedure ER-AA-335-018. All surface areas with flaking, chipping, blistering, peeling, pinpoint rusting, cracking, chalking, and discoloration attributable to rust blooms shall be entered into the Corrective Action Program and evaluated by Engineering.

3.2.6.2.1.2 Discoloration due to loose surface residue due to surface wetting on the foam is acceptable so long as the coating below the residue not degraded. A clean cloth shall clean off the loose surface residue.

3.2.6.2.1.3 Minor flaking, chipping and peeling is acceptable. Minor flaking, chipping and peeling is defined as follows: isolated flaking, chipping and peeling where: the loose coating is less than a ¼ square inch, is on the surface of the coating and does not penetrate to the base metal. The purpose of this exception is to allow minor physical damage that may have been caused by the removal of the foam and is not indicative of coating breakdown.

3.2.6.2.2 Vessel Thickness Acceptance Criteria

Readings less than 0.660" shall be entered into the corrective action program and evaluated by Engineering. This acceptance criteria is based on the minimum recorded readings in 1987 (reference NDE data sheet 87-026–64), a 20 mil tolerance, and a 10 mil per year corrosion rate between 1987 and 1992. The acceptance criteria are not based on the minimum required code thickness, which is less than the above value.

3.2.6.3 Data Retention

3.2.6.3.1 Coating inspections shall be documented for each bay on an NDE data sheet. The data sheets shall also include: the date and time of the

examination, the examination method, the governing procedure, Examiner, and Reviewer.

3.2.6.3.2 All UT readings values within each trench shall be documented on an NDE data sheet and formatted in a 7 column format similar to NDE data sheet 86-049-047 and 86-049-056 (please refer reference 2.7). The data sheet shall also include: the date and time of the examination, location of the core plugs, the examination method, the ID number of the equipment, the governing procedure, the ID number of the cal block, the location surface temperature, Examiner, Reviewer, Location ID in accordance with table 2.

3.2.6.4 Required Support and Tools

3.2.6.4.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.6.4.2 Remove the existing foam in the trench in accordance with an approved work order.

3.2.6.4.3 After the UT inspections are complete and the coating has been repaired, if applicable. Reinstall the foam in accordance with an approved work order and reference 2.11.

3.2.7 UT Inspection of Weld Joint at Elevation 23' 6 7/8"

3.2.7.1 Background

At elevation 23' 6 7/8" there is circumferential weld which joins the bottom spherical plates and the middle spherical plates. This weld joins plates that are 1.154" thick to the plates that are 0.770" thick. The edges of the 1.154 thick plates were fabricated with a taper to provide a smooth transition to the thinner plates.

3.2.7.2 Locations

3.2.7.2.1 Two separate locations shall be inspected per the requirements of section 3.2.7.3.

3.2.7.2.2 This weld joint is located at nearly the same elevation as the grating at elevation 23' 6". The 1.154 thick plates are located below the grating. The "as built" drawings do not provide enough information to determine if there is enough clearance between the grating and the side of the Drywell to allow NDE inspectors access to the lower plates. Therefore the two inspection locations will be selected by the NDE and Engineering, based on accessibility to the lower plate. To the extent possible the two inspection locations shall be selected within Bays 17, 19, 13, or 15. These bays have historically experienced the most corrosion in the sandbed region. If necessary portions of the grating may have to be removed.

3.2.7.3 Inspection Requirements

3.2.7.3.1 Inspection of the 1.154" Plate

3.2.7.3.1.1 Dynamic UT inspections of the 1.154" thick plate shall be performed through the existing coating below the taper (see exhibit 6). Dynamically scan an area that is a nominally of 6" wide by 6" high. Record the average and maximum thickness. Also characterize and document all areas within this 6" by 6" area that are less than 0.96 inches thick.

3.2.7.3.1.2 During this first inspection, mark this area with a low stress dye stamp so that repeat inspections can be performed in the future. This shall be accomplished by marking two corners of the 6" by 6" area.

3.2.7.3.1.3 If UT inspection (per the above paragraphs) of the 1.154" thick plate cannot be performed due to interference between the grating and the side of the drywell and if the grating cannot be easily removed, document the discrepancy into the Corrective Action Process for evaluation by Engineering.

3.2.7.3.2 Inspection of the 0.770" plate

3.2.7.3.2.1 Dynamic UT inspections of the 0.770" plate shall be performed through the existing coating above the weld. Dynamically scan an area that is a nominally of 6" wide by 6" high (see exhibit 6). Record the average and maximum thickness. Also characterize and document all areas within this 6" by 6" area that are less than 0.740 inches thick.

3.2.7.3.2.2 During the first inspection, mark this area with a low stress dye stamp so that repeat inspections can be performed in the future. This shall be accomplished by marking two corners of the 6" by 6" area.

3.2.7.3.3 Inspection of the Weld

3.2.7.3.3.1 Dynamic UT thickness inspection of the weld between the two 6" x 6" areas described above. Grind the weld crown flat if necessary. 100% of the weld area shall be inspected.

3.2.7.3.3.2 Review of the original construction drawings for the drywell vessel (CBI drawing 9-0971 sheet 4, details "Joint

R", "Joint D" and "Joint E") show that this weld was required to be flush. Therefore, most likely "Flat Top" process will not be required. However, it is possible the weld may have slight crown that was not completely flush. In this case the Flat Top process will simply remove the slight crown.

3.2.7.3.3.3 After the UT inspection is complete coat the exposed weld location with Versilube G351 grease or an approved alternative.

3.2.7.4 Acceptance Criteria

3.2.7.4.1 On the 0.770" thick plate and the weld, readings less than 0.655" shall be entered into the corrective action program and evaluated by Engineering. This acceptance criteria is based on the minimum recorded local readings found in the sphere during the 1991 random inspections and a 20 mil tolerance. This acceptance criteria is <u>not</u> based on the minimum required code thickness, which is less than the above value.

3.2.7.4.2 On the 1.154" thick plate readings less than 0.90" shall be entered into the corrective action program and evaluated by Engineering. This acceptance criteria is based on the minimum recorded local readings found in the sphere during the 1991 random inspections and a 20 mil tolerance. This acceptance criteria is not based on the minimum required code thickness, which is less than the above value.

3.2.7.5 Data Retention

All readings and areas sizes for each location shall be documented on an NDE data sheet. In addition the location of the inspected area shall be clearly documented so that this same location can be inspection in the future. The data sheet shall also include: the date and time of the examination, the examination method, the ID number of the equipment, the governing procedure, the ID number of the cal block, the location surface temperature, Examiner, Reviewer, Location ID in accordance with table 3.

3.2.7.6 Required Support and Tools

3.2.7.6.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.7.6.2 The weld in the area must be ground flat prior to the inspection.

3.2.8 UT Inspection of Weld Joint at Elevation 71' 6"

3.2.8.1 Background

At elevation 71' 6" there is circumferential weld which joins the transition plates (referred to as the knuckle) between the cylinder and the sphere. This weld joins the knuckle plates, which are 2 5/8" thick to the cylinder plates, which are 0.64" thick. The edges of the 2 5/8" thick plates were fabricated with a 3 to 12 taper to provide a smooth transition to the thinner plates.

3.2.8.2 Locations/Scaffolding

3.2.8.2.1 Two separate locations shall be inspected per the requirements of section 3.2.8.3.

3.2.8.2.2 Inspection of this weld joint in two locations will require the erection of scaffolding from the drywell platform at elevation 47'. The inside of the Drywell at this elevation is very congested. Therefore the NDE, Engineering, and the trade that will erect the scaffolding will select the actual location. This will ensure that the inspection and scaffolding erection will be performed safely. To the extent possible the two inspection locations shall be selected within Bays 17, 19, 13, or 15. These bays have historically experienced the most corrosion in the sandbed region. These are areas that are generally located above the 1-1, 1-2, and 1-5 Drywell Cooling Units.

3.2.8.3 Inspection Requirements

3.2.8.3.1 Inspection of the 2 5/8" plate

3.2.8.3.1.1 Dynamic UT inspections of the 2 5/8" thick plate shall be performed through the existing coating below the taper on the plate (see exhibit 6). Dynamically scan an area that is a nominally of 6" wide by 6" high. Record the average and maximum thickness. Also characterize and document all areas within this 6" by 6" area that are less than 2.55 inches thick.

3.2.8.3.1.2 During this first inspection, mark this area with a low stress dye stamp so that repeat inspections can be performed in the future. This shall be accomplished by marking two corners of the 6" by 6" area.

3.2.8.3.2 Inspection of the 0.64" plate

3.2.8.3.2.1 Dynamic UT inspections of the cylinder plate shall be performed through the existing coating above the weld. Dynamically scan an area that is a nominally of 6" wide by 6" high. Record the average and maximum thickness. Also characterize and document all areas within this 6" by 6" area that are less than 0.585 inches thick.

3.2.8.3.2.2 During this first inspection, mark this area with a low stress dye stamp so that repeat inspections can be performed in the future. This shall be accomplished by marking two corners of the 6" by 6" area.

3.2.8.3.3 Inspection of the weld

3.2.8.3.3.1 Dynamic UT thickness inspection of the weld between the two 6" x 6" areas described above. Grind the weld crown flat if necessary. 100% of the weld area shall be inspected.

3.2.8.3.3.2 Review of the original construction drawings for the drywell vessel (CBI drawing 9-0971 sheet 4, details "Joint R", "Joint D" and "Joint E") show that this weld was required to be flush. Therefore, most likely "Flat Top" process will not be required. However, it is possible the weld may have slight crown that was not completely flush. In this case the Flat Top process will simply remove the slight crown.

3.2.8.3.3.3 After the UT inspection is complete coat the exposed weld location with Versilube G351 grease or an approved alternative.

3.2.8.4 Acceptance Criteria

3.2.8.4.1 On the cylinder plate (nominally 0.64") and the weld, readings less than 0.56" shall be entered into the corrective action program and evaluated by Engineering. This acceptance criteria is based on minimum recorded readings found in the cylinder during the 1991 random inspections and a 20 mil tolerance. This acceptance criteria is not based on the minimum required code thickness, which is less than the above value.

3.2.8.4.2 On the knuckle plate (nominally 2 5/8") readings less than 2.490" shall be entered into the corrective action program and evaluated by Engineering. This acceptance criteria is based on minimum recorded readings during the 1991 random inspections and a 20 mil tolerance. This acceptance criteria is not based on the minimum required code thickness, which is less than the above value.

3.2.8.5 Data Retention

All readings and areas sizes for each location shall be documented on an NDE data sheet. In addition the location of the inspected area shall be clearly documented so that this same location can be inspection in the future. The data sheet shall also include: the date and time of the examination, the examination method, the ID number of the equipment, the governing procedure, the ID number of the cal block, the location surface temperature, Examiner, Reviewer, Location ID in accordance with table 3.

3.2.8.6 Required Support and Tools

3.2.8.6.1 Safety and Radcon support and coverage shall be provided as necessary.

3.2.8.6.2 To provide access to this welded joint, the station must erect scaffolding from elevation 47'.

3.2.8.6.3 The weld in the area must be ground flat prior to the inspection.

3.2.8.6.4 Remove the scaffolding.

4 Quality Assurance

4.1 The following work shall be performed in accordance with the Exelon Quality Assurance Program as follows:

4.1.1 UT and Visual Inspection shall be performed in accordance with approved procedures as described in section 3.1.2 and this specification.

4.1.2 UT inspections for sections 3.2.1, 3.2.2 and 3.2.3 shall be performed with a template that meets the dimensional requirements in exhibit 2 of this specification.

4.1.3 Resulting calculation(s) shall be developed and approved in accordance with Exelon approved procedures

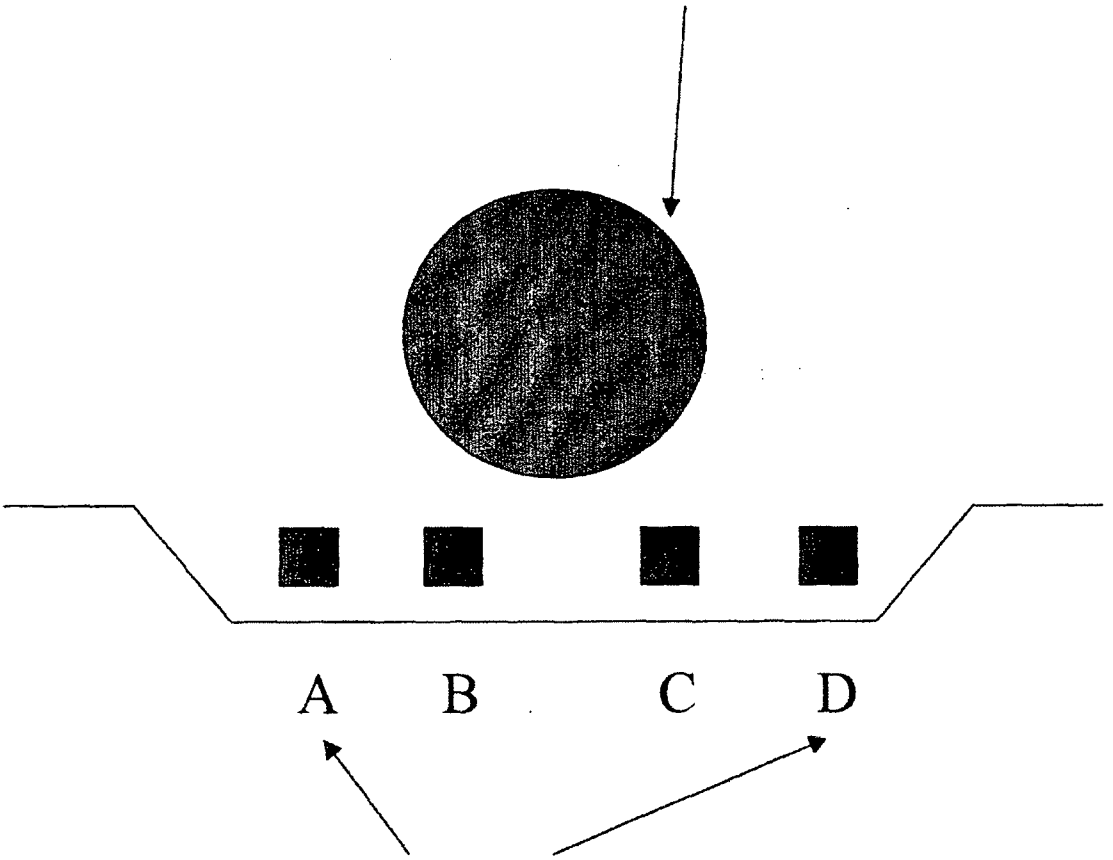
Table 4 – Inspection Schedule

Inspection	2006	2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
Internal UT Inspection in upper elevations per section 3.2.1	Yes – all locations		Yes – all locations		Yes – all locations		Yes – all locations		Yes – all locations		Yes – all locations	
Internal UT Inspection in sandbed region per section 3.2.2	Yes – all locations		Yes – all locations					Yes – all locations				
External UT Inspection of Locally Thin Areas in Bay 1 and 13 per section 3.2.3	Yes – all locations											
Visual inspection of Former Sandbed coating per section 3.2.4	Yes – Bays 1, 5, 7, 9, 13, 15 and 19	Yes – Bays 3, 11, and 17		Yes – Bays 1, 3, 13, 17, and 19		Yes – Bays 5, 7, 9, 11, and 15		Yes – Bays 1, 3, 13, 17, and 19		Yes – Bays 5, 7, 9, 11, and 15		
Inspection of Sandbed drain lines per section 3.2.5	Yes – drains corresponding to Bay 1, 5, 7, 9, 13, 15 & 19	Yes – drains corresponding to Bays 3, 11, & 17		Yes – drains corresponding to Bays 1, 13, 17 & 19		Yes – drains corresponding to Bays 5, 7 11 and 15		Yes – drains corresponding to Bays 1, 13, 17 and 19		Yes – drains corresponding to Bays 5, 7 11 and 15		
Internal UT Inspection in Trenches per section 3.2.6	Yes – all locations											
Internal Visual Inspection in Trenches per section 3.2.6	Yes –all locations											
UT Inspection of Weld Joint at Elevation 23' 6 7/8" per section 3.2.7	Yes		Yes									
UT Inspection of Weld Joint at Elevation 71' 6" per section 3.2.8	Yes		Yes									

Exhibit 1

Typical Orientation of Inspection Locations in the Sandbed Region

View - looking from inside the drywell



Location IDs = Bay Number plus one of these letters: i.e. – "11D"

Exhibit 2

Template shall be made of Stainless Steal, approximately 0.30 inches thick, with 49 holes centered on a 1 inch pattern.

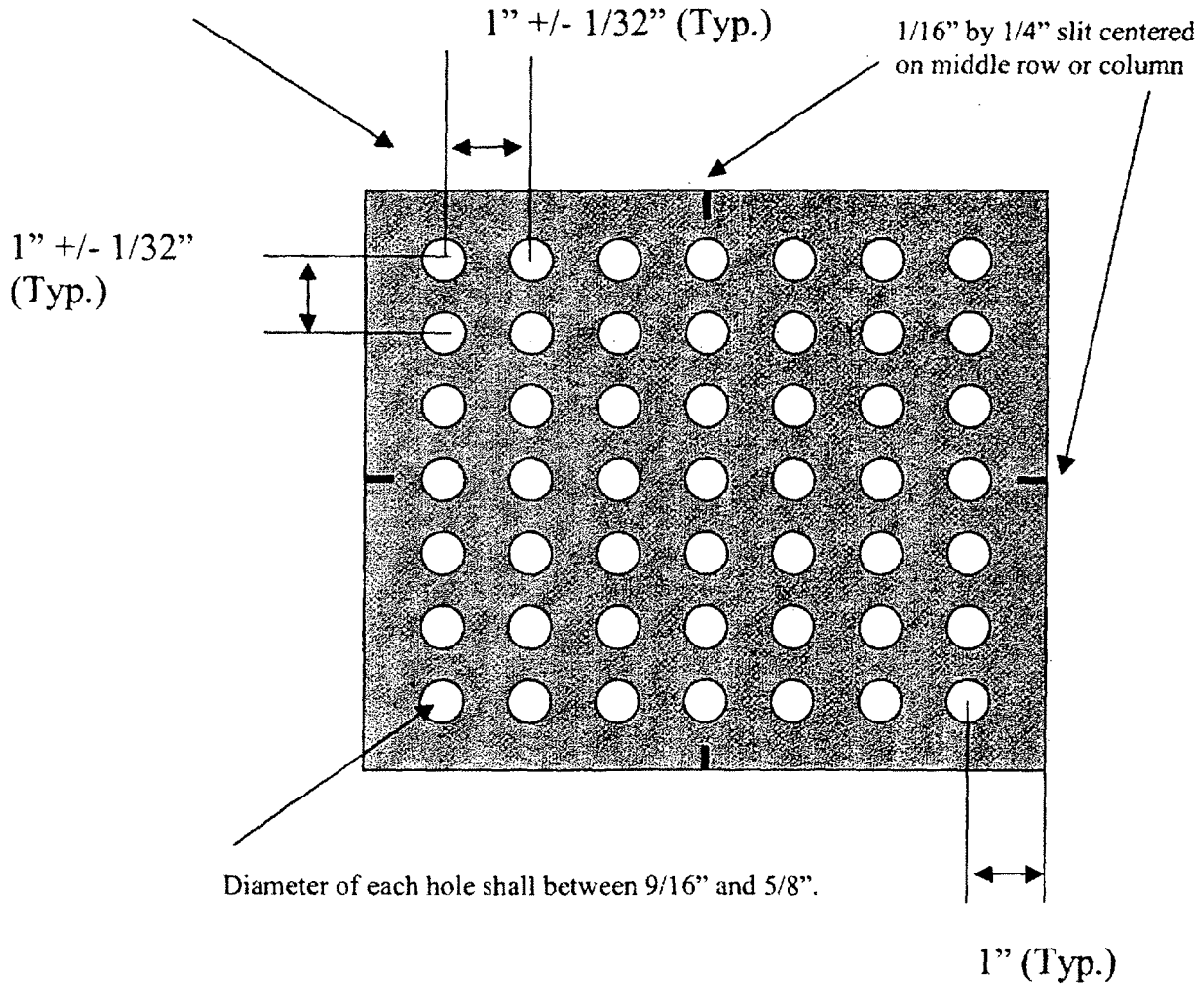


Exhibit 3

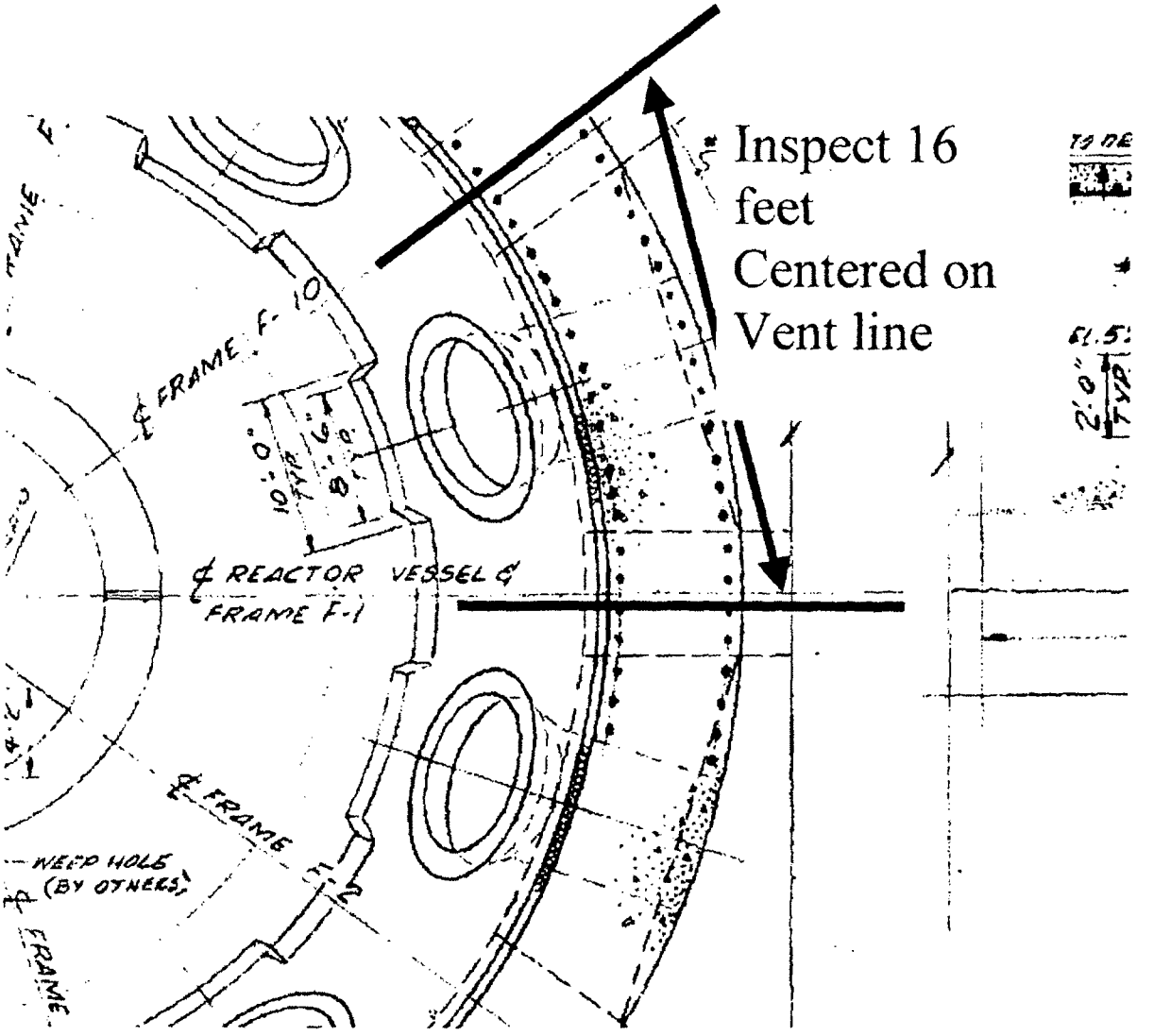

Inspect 16 feet Centered on Vent line
℄ FRAME F-10
℄ REACTOR VESSEL ℄
FRAME F-1
℄ FRAME
WEEP HOLE (BY OTHERS)
℄ FRAME

Exhibit 4

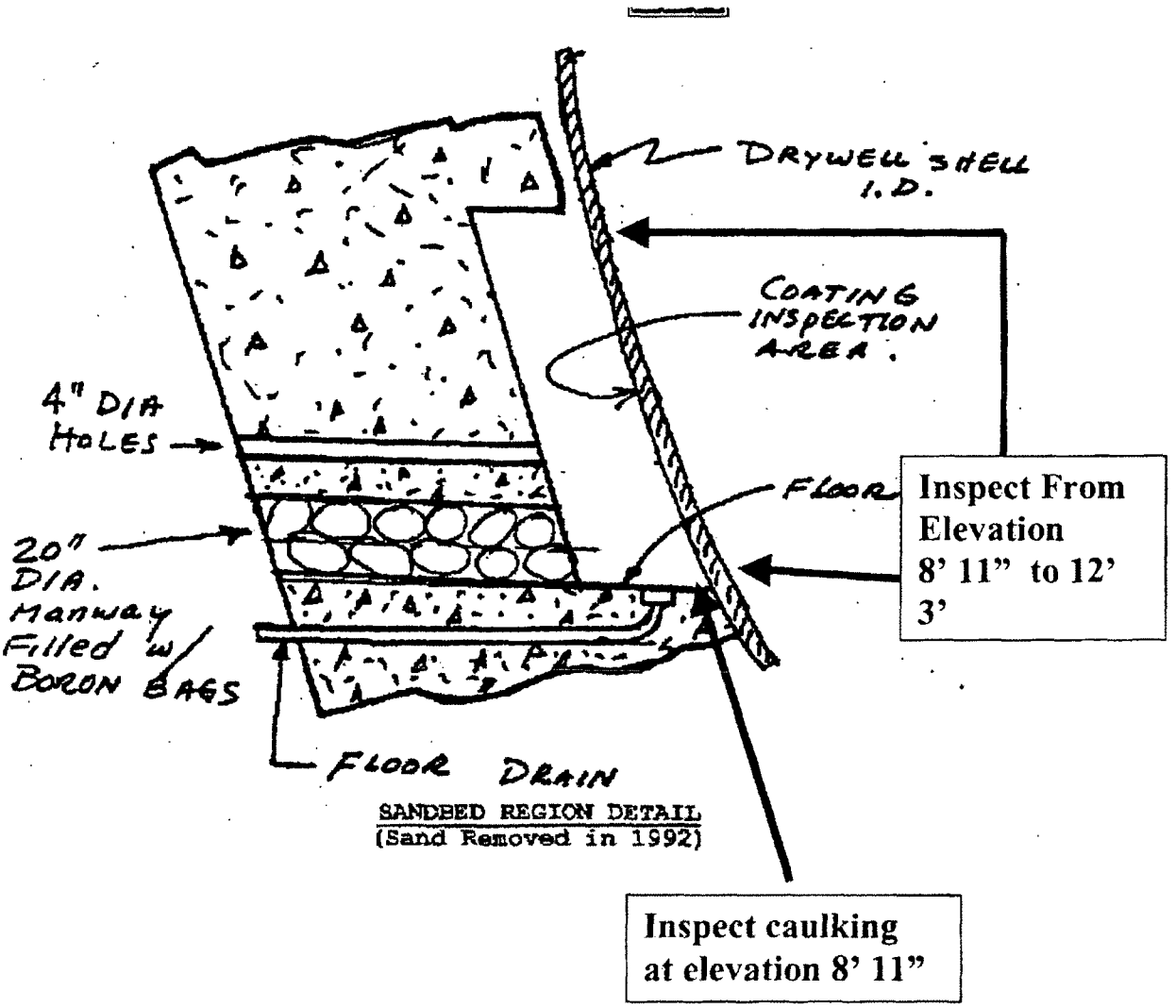
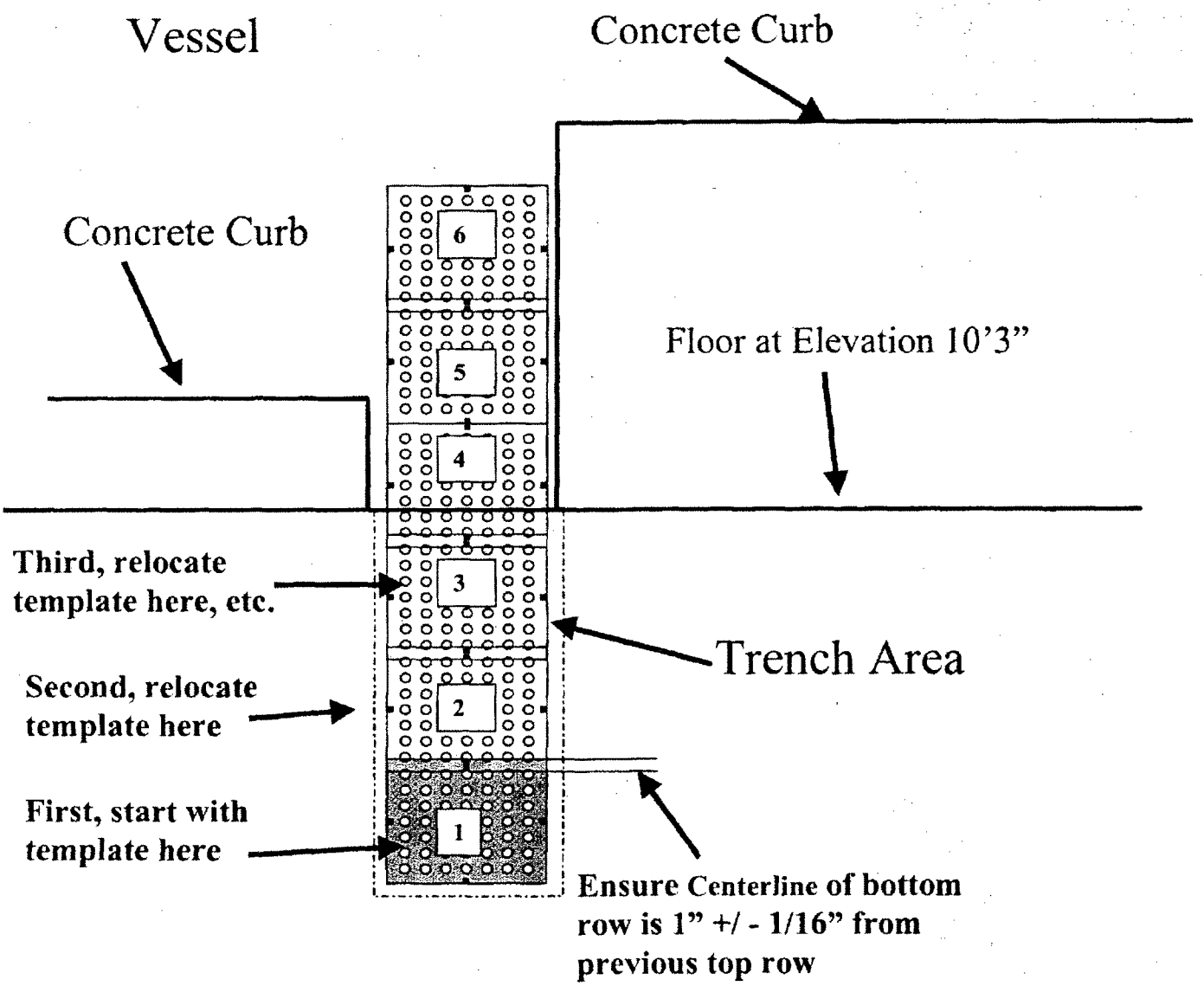
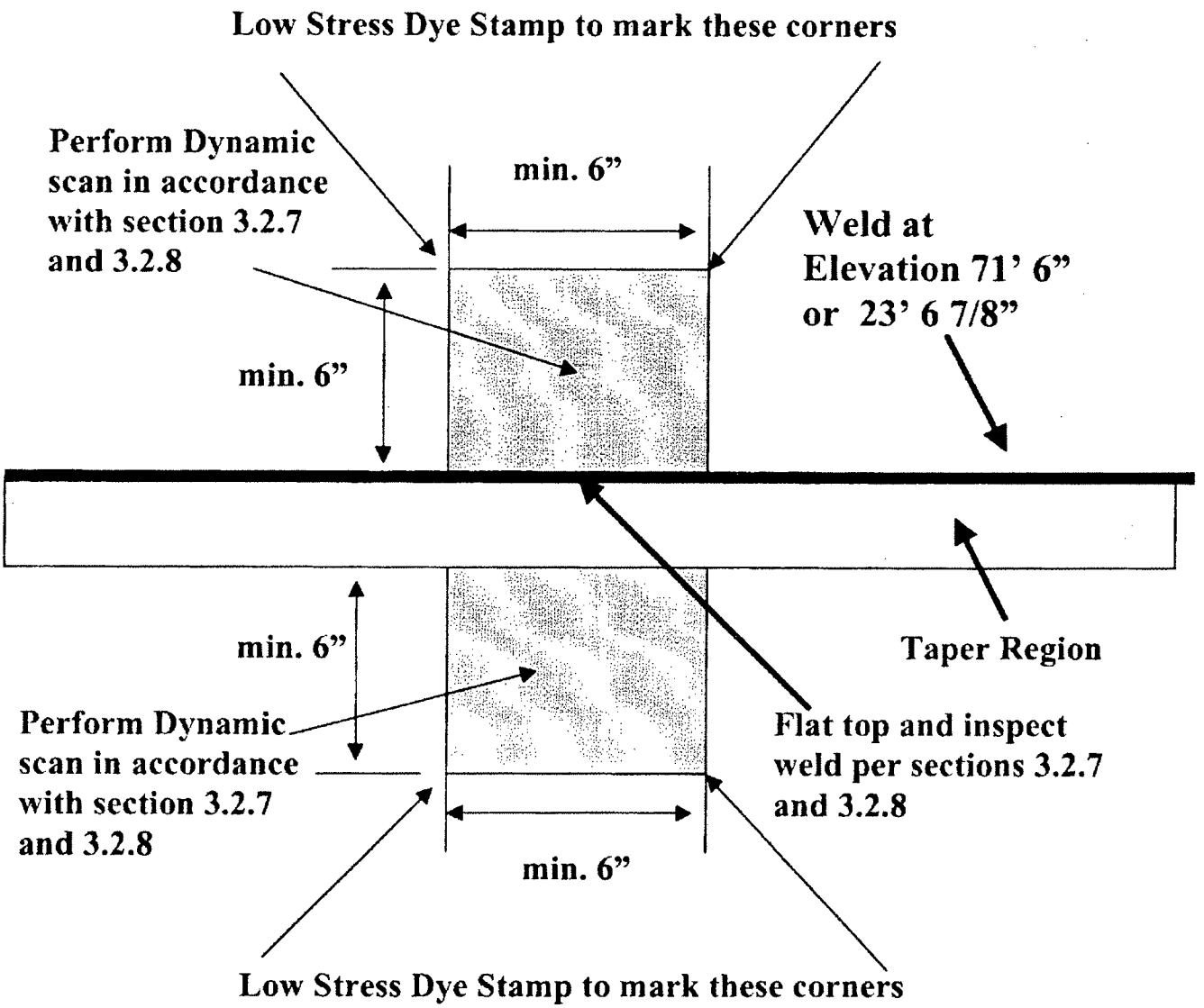

DRYWELL SHELL I.D.
COATING INSPECTION AREA.
4" DIA HOLES
FLOOR
20" DIA. Manway Filled w/ BORON BAGS
FLOOR DRAIN
SANDBED REGION DETAIL
(Sand Removed in 1992)
Inspect From Elevation 8' 11" to 12' 3'
Inspect caulking at elevation 8' 11"

Exhibit 5



Elevation View of Trenches

Exhibit 6



Elevation View

ATTACHMENT 1
Design Analysis Cover Sheet

Design Analysis (Major Revision)	**Last Page No.** [6] **114**
Analysis No.: [1] C-1302-187-5320-024	**Revision:** [2] 1
Title: [3] OC Drywell Ext. UT Evaluation in Sandbed	
EC/ECR No.: [4]	**Revision:** [5]

		Component(s): [14]	
Station(s): [7]	Oyster Creek		
Unit No.: [8]	1		
Discipline: [9]	Mechanical/Structural Eng.		
Descrip. Code/Keyword: [10]	UT Data Assessments		
Safety/QA Class: [11]	Q		
System Code: [12]	187		
Structure: [13]	Drywell Vessel		

CONTROLLED DOCUMENT REFERENCES [15]

Document No.:	From/To	Document No.:	From/To
GE # Index 9-4	From		
GE # Index 9-3	From		
GE Letter Report: "Sandbed Local Thinning and Raising the Fixity Height Analysis"	From		

Is this Design Analysis Safeguards Information? [16] **Yes** ☐ **No** ☒ If yes, see SY-AA-101-106

Does this Design Analysis contain Unverified Assumptions? [17] **Yes** ☐ **No** ☒ If yes, ATI/AR#:

This Design Analysis SUPERCEDES: [18] **in its entirety.**

Description of Revision (list affected pages for partials): [19] Revised Calculation to clarify methods used to evaluate UT Measurements of the external Drywell Shell. Also, reformatted portions of the calculation to bring it inline with the existing calculation procedure at Oyster Creek Generating Station. Revised or added the following pages: 3, 4, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 21, 23, 25, 27, 30, 32, 33, 34, 35, 36, 37, 39, 40, 42, 43, and 45. Also added Appendix D, NDE Inspection Sheets

Preparer: [20]	Jeffrey H. Horton (Enercon)	for J. HORTON	04/14/06
	Print Name	Sign Name	Date

Method of Review: [21] **Detailed Review** ☒ **Alternate Calculations (attached)** ☐ **Testing** ☐

Reviewer: [22]	Omesh Abhat (Enercon)	O Abhat	04/14/06
	Print Name	Sign Name	Date

Review Notes: [23] Independent review ☒ Peer review ☐

Review of the revised part of the calculation has been performed and is acceptable. The review (Rev. 1) addresses clarification of the original calculation only as described above under Description of Revision. Analytical buckling inputs are taken from References 3.3 (Table 4.1) and 3.5. They are assumed acceptable inputs for this calculation as provided by the client.

(For External Analyses Only)

External Approver: [24]	Don Shivas (Enercon)		04/14/06
	Print Name	Sign Name	Date
Exelon Reviewer: [25]			
	Print Name	Sign Name	Date

Is a Supplemental Review Required? [26] **Yes** ☐ **No** ☐ If yes, complete Attachment 3

Exelon Approver: [27]			
	Print Name	Sign Name	Date

AmerGen	DOCUMENT NO. C-1302-187-5320-024

TITLE: OC Drywell Ext. UT Evaluation in Sandbed

REV	SUMMARY OF CHANGE	APPROVAL	DATE
0	Initial Issue	GPU Nuclear Signatures on File	04/16/93
1	Revised Calculation to clarify methods used to evaluate UT Measurements of the external Drywell Shell. Also, reformatted portions of the calculation to bring it inline with the existing calculation procedure at Oyster Creek Generating Station. Revised or added the following pages: 3, 4, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 21, 23, 25, 27, 30, 32, 33, 34, 35, 36, 37, 39, 40, 42, 43, and 45. Also added Appendix D, NDE Inspection Sheets	Jeffrey H. Horton Enercon Services Omesh Abhat Enercon Services Don Shivas Enercon Services	04/14/06 04/14/06 04/14/06

Table of Contents

Section **Page**

1.0 PROBLEM STATEMENT:

The purpose of this calculation is to evaluate the UT thickness measurements taken in the sandbed region during the 14R outage in support of the O.C. drywell corrosion mitigation project. These measurements were taken from the outside of the shell. Access to the sandbed region was achieved by cutting ten holes completely through the shield wall from the torus room.

2.0 SUMMARY OF RESULTS:

This calculation demonstrates that the UT thickness measurements for all bays meet the minimum uniform and local required thicknesses.

The evaluation was performed by evaluating the UT measurements for each bay and dispositioning them relative to the uniform thickness of 0.736 inch used in the GE structural analysis reports References 3.2, 3.3 and 3.5. Additional acceptance criteria was developed to address measurements below 0.736 inch. The results are summarized in Table 1.

UT measurements for bays 3, 5, 7, 9, and 19 were all above the 0.736 inches and therefore acceptable.

UT measurements for bays 11, 15, and 17 were all above 0.736 inches except for one measurement for each bay. After further evaluation of these three measurements including an examination of adjacent areas, it was determined that they were acceptable as shown on Table 1.

UT measurements for bays 1 and 13 were evaluated using detailed criteria described in this calculation and the results are summarized in Table 1 below:

SUMMARY OF UT EVALUATIONS
TABLE (2-1)

Drywell Bay	General Sandbed Shell Thickness(1)			Local Sandbed Thickness(2)			Comments
	Thickness Criteria Inches	Actual Thickness inches	Acceptable Yes/No	Thickness Criteria Inches	Actual Thickness	Acceptable Yes/No	
1	0.736" whole Bay	UT_{Avg}=0.822 T_{Eval}=0.766	Yes Yes	0.636" over a 12"x12" area	T_{Eval} = 0.692" Over a 4"x4" area	Yes	See Pages 15 through 21 for details of evaluation
3	0.736" whole Bay	UT_{Avg}=0.868	Yes	0.636" over a 12"x12" area	N/A	N/A	No locations in bay are below 0.736". See Pages 22 & 23
5	0.736" whole Bay	UT_{Avg}=0.986	Yes	0.636" over a 12"x12" area	N/A	N/A	No locations in bay are below 0.736". See Pages 24 & 25
7	0.736" whole Bay	UT_{Avg}=1.001	Yes	0.636" over a 12"x12" area	N/A	N/A	No Locations in bay are below 0.736" see Pages 26 & 27
9	0.736" whole bay	UT_{Avg}=0.915	Yes	0.636" over a 12"x12" area	N/A	N/A	No Locations in bay are below 0.736" see Pages 28 and 29
11	0.736" whole bay	UT_{Avg}=0.792 T_{Eval}=0.751	Yes	0.636" over a 12"x12" area	N/A	N/A	One location with a thickness less than 0.736" but not greater than 2" in Dia. See Pages 30 to 32
13	0.736" whole bay	UT_{Avg}=0.810 T_{Eval}=0.767	Yes	0.636" over a 12"x12" area	T_{Eval}=0.693"over a 6"x6" area	yes	See pages 33 through 39 for details of evaluation
15	0.736" Whole Bay	UT_{Avg}=0.816 T_{Eval}=0.859	Yes	0.636" over a 12"x12" area	N/A	N/A	One location with a thickness less than 0.736" but not greater than 2" in Dia. See Pages 40 to 42
17	0.736" Whole Bay	UT_{Avg}=0.918 T_{Eval}=0.871	Yes	0.636" over a 12"x12" area	N/A	N/A	One location with a thickness less than 0.736" but not greater than 2" in Dia. See Pages 43 to 45
19	0.736" Whole Bay	UT_{Avg}=0.885	Yes	0.636" over a 12"x12" area	N/A	N/A	No Locations in bay are below 0.736" see Pages 46 and 47

Notes: 1. UT_{Avg} are the average shell thickness readings using a D-Meter in local areas not less than the buckling design thickness of 0.736" these areas do not exceed 2" in diameter. T_{Eval} is the average calculated Thickness of the shell surrounding areas not exceeding 2" in diameter that have UT D-Meter shell thickness readings less than 0.736". See Section 6, Methods of Analysis, Acceptance Criteria – General Wall (Sandbed Region) for details.

2. Small Areas of reduced thickness 2&½" or less in diameter have a negligible effect on shell buckling. See Section 6 Methods of Analysis, Acceptance Criteria –Very Local Wall (2½ Inches in Diameter) for details.

3.0 REFERENCE:

3.1 Drywell sandbed region pictures (Appendix C).

3.2 An ASME Section VIII Evaluation of the Oyster Creek Drywell for Without Sand Case Performed by GE – Part 1 Stress Analysis, Revision 0 dated February, 1991 Report 9-3.

3.3 An ASME Section VIII Evaluation of the Oyster Creek Drywell for Without Sand Case Performed by GE – Part 2 Stability Analysis, Revision 2 dated November, 1992 Report 9-4.

3.4 ASME Section III Subsection NE Class MC Components 1989.

3.5 GE letter report "Sandbed Local Thinning and Raising the Fixity Height Analysis (Line Items 1 and 2 In Contract PC-0391407)" dated December 11, 1992.

3.6 GPUN Memo 5320-93-020 From K. Whitmore to J. C. Flynn "Inspection of Drywell Sand Bed Region and Access Hole", Dated January 28, 1993.

3.7 Theory of Elastic Stability, by Stephen P. Timoshenko and James M. Gere, Second Edition, Engineering Societies Monographs, McGraw Hill Book Company, New York, 1961

4.0 ASSUMPTIONS AND BASIC DATA:

4.1 Raw UT measurements for each bay are presented in Appendix D and summarized in the body of calculation.

4.2 References 3.2, 3.3 and 3.5 have been design verified and are assumed correct.

5.0 DESIGN INPUTS:

5.1 Observations of the outside surface of the drywell shell indicate a rough surface with varying peaks and valleys. In order to characterize an average roughness representing the depth difference of peaks and valleys, two impressions were made at the two lowest UT measurements for bay 13 using Epoxy putty.

Appendix A presents the calculation of the depth of surface roughness using the drywell shell impressions taken in the roughest bay. Two locations in bay 13 were selected since it is the roughest bay. Approximately 40 locations within the two impressions were measured for depth and the average plus one standard deviation was calculated. A value of 0.200 inch was used in this calculation as a conservative depth of uniform roughness for the entire outside surface of the drywell in the sandbed region. This is defined as Trough.

5.3 5.2 Drywell Design Pressure = 44.0 psig, Oyster Creek, UFSAR Revision 13, Section 3.8.2.8, Page 3.8-61

Drywell Design Temperature = 292°F, Oyster Creek, UFSAR Revision 13, Table 3.11-1

The required sandbed shell thickness for the Design Pressure and Temperature is defined in paragraph ASME B&PV Code, Subsection NE, paragraph NE-3324.4, Spherical Shells, as:

$$t = \frac{PR}{2S - 0.2P}$$ Where: P = Design Pressure

R = Inside Radius of the Shell = 420 inches

S = Maximum Allowable Stress, SA 212 Grade B = 19,300 psi (From ASME B&PV Code Section VIII 1962 Edition and Reference 3.2, Section 2.2)

$$t = \frac{(44.0\text{psig})(420.0'')}{2(19{,}300\text{psi}) - 0.2(44.0\text{psig})} = 0.4789 \text{ inches}$$

5.4 Drywell Sandbed buckling design thickness is 0.736 inches. Taken from References 3.3, and 3.5

5.5 Analytical design inputs are taken from References 3.3, 3.4 and 3.5

6.0 METHODS OF ANALYSIS:

Acceptance Criteria - General Wall (Sandbed Region):

The acceptance criteria used to evaluate the measured drywell thickness is based upon GE reports 9-3 and 9-4 (Ref. 3.2 & 3.3) as well as other GE studies (Ref. 3.5) plus visual observations of the drywell surface (Ref. 3.6 and Appendix C). The GE reports used a projected uniform thickness of 0.736 inches in the sandbed area taken from References 3.3, and 3.5. This area is defined to be from the bottom to top of the sandbed, i.e., El. 8'-11½" to El. 12'-3" and extending circumferentially one full bay. Therefore, if all the UT measurements for thickness in one bay are greater than 0.736 inches the bay is evaluated to be acceptable. In bays where measurements are below 0.736 inches, more detailed evaluation is performed.

This detailed evaluation is based, in part, on visual observations of the shell surface plus a knowledge of the inspection process. The first part of this evaluation is to arrive at a meaningful value for the general sandbed shell thickness for use in the structural assessment. This meaningful value is referred to as the thickness for evaluation. It is computed by accounting for the depth of the spot where the thickness measurement is taken considering the roughness of the shell surface. The surface of the shell has been

characterized as being "dimpled" as in the surface of a golf ball where the dimples are about one half inch in diameter (Appendix C). Also, the surface contains some depressions 12 to 18 inches in diameter not closer than 12 inches apart, edge to edge (Ref. 3.6). Appendix A presents the calculation of the depth of surface roughness using the drywell shell impressions taken in the roughest bay. Two locations in bay 13 were selected since it is the roughest bay. Approximately 40 locations within the two impressions were measured for depth and the average plus one standard deviation was calculated to be at 0.186 inches. A value of 0.200 inch was used in this calculation as a conservative depth of uniform dimples for the entire outside surface of the drywell in the sandbed region.

The inspection focused on the thinnest portion of the drywell, even if it was very local, i.e., the inspection did not attempt to define a shell thickness suitable for structural evaluation. Observations indicate that some inspected spots are very deep. They are much deeper than the normal dimples found, and very local, not more than 1 to 2 inches in diameter. (Typically these observations were made after the spot was surface prepped for UT measurement. This results in a wide dimple to accommodate the meter and slightly deeper than originally found by 0.030 to 0.100 inches). The depth of these areas was measured with a depth gauge and straight edge at 0^0, 45^0, 90^0 and 135^0 around these inspected dimples. The depths obtained were averaged with respect to the tops of the locally rough areas. These depths are referred to herein as the AVG micrometer measurements. As these AVG micrometer measurements are very local in nature their effect on the structural response of the drywell to applied loads is very limited. A more meaningful shell thickness for the drywell structural response to applied loads is the general shell thickness near the UT measured indications. This can be obtained on a smooth shell exterior surface by adding the UT measured thickness at the bottom of the indication and the AVG micrometer measurements of the indication depth. But because the exterior of the drywell shell in the sandbed region is very rough and dimpled the measurement described above would give optimistic general shell thicknesses near the indications (See Figure 6.1). To determine a conservative general shell thickness at the locations of interest Design Input 5.1 of this calculation is subtracted from the combination of the UT measurement and the depth micrometer readings. This thickness is then used to determine the drywell shell susceptibility to buckling by comparing this thickness to the buckling design thickness of 0.736 inches. This thickness is referred to as the evaluation thickness which as described above is computed as:

T (evaluation) = UT (measurement) + AVG (micrometer) - T_{rough}

where:

T (evaluation)	=	General shell thickness used for the evaluation
UT (measurement)	=	thickness measurement at the area (location)
AVG (micrometer)	=	average depth of the area relative to its immediate surroundings
T_{rough}	=	0.200 inches = a conservative value of depth of typical dimple on the shell surface. See Design Input 5.1.

After this calculation, if the thickness for analysis is greater than 0.736 inches; the area is evaluated to be acceptable.

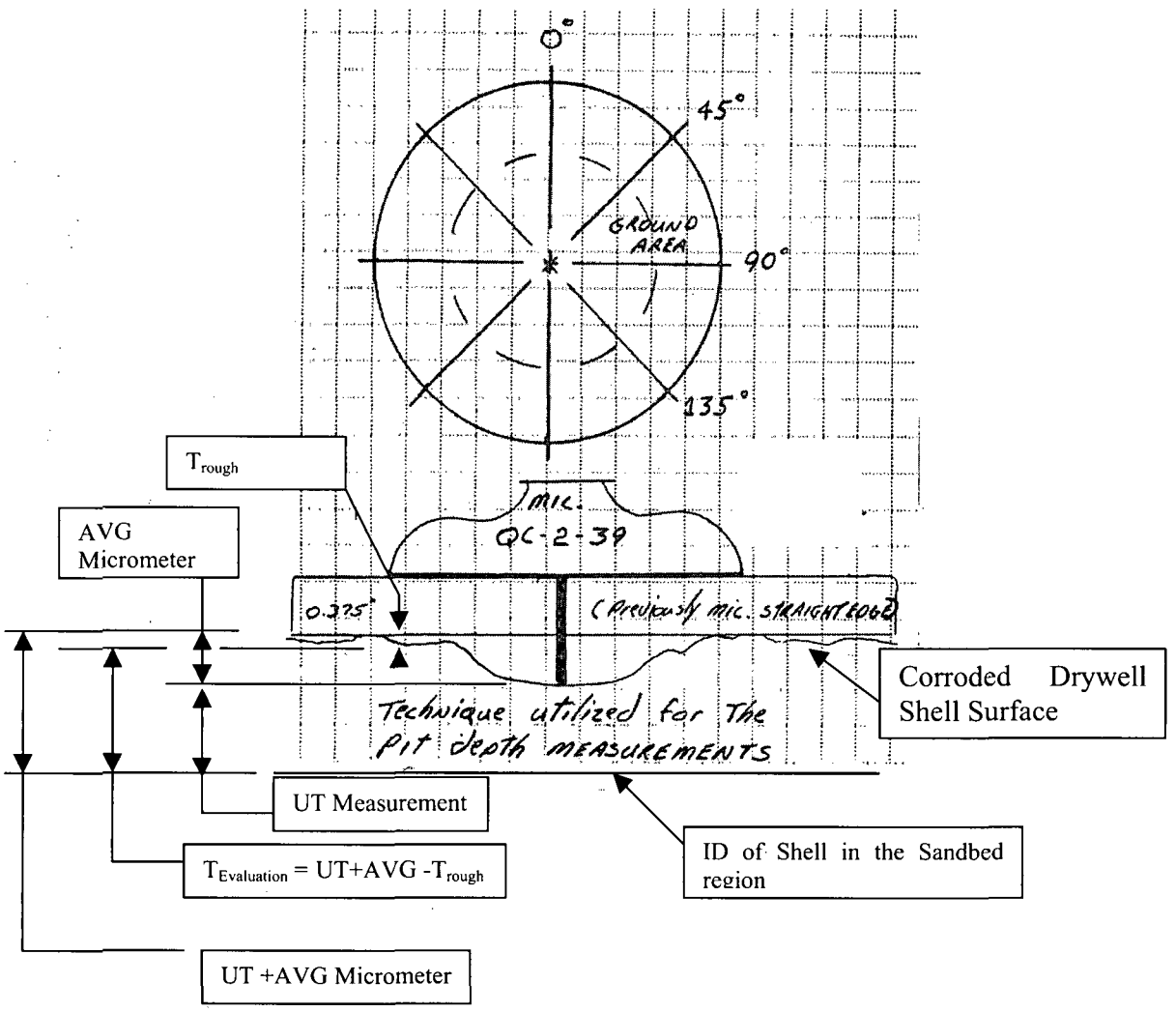


FIGURE 6.1

Acceptance Criteria – Local Wall:

If the thickness for evaluation is less than 0.736 inches, then the use of specific GE studies is employed (Ref. 3.5). The studies in Reference 3.5 do not reflect actual drywell shell conditions but are used as assessment tools for areas of the sandbed region that have reduced thicknesses. The methodology used in these studies is provided in reference 3.3 with a excerpt provided here. The studies contain a two step eigenvalue formulation procedure to perform linear elastic buckling analysis of the drywell shell with local areas of reduced thickness. The first step is a static analysis of the structure with all the anticipated loads applied. The structural stiffness matrix, [K], the stress stiffness matrix, [S], and the applied stresses, $\lfloor \sigma_{ap} \rfloor$, are developed and saved from this static analysis. A buckling pass is then run to solve for the lowest eigenvalue or load factor, λ, for the whole structure at which elastic buckling can occur. This load factor, or eigenvalue is a multiplier for the applied stress state or applied load at which the onset of elastic buckling will theoretically occur. All the applied stresses in the structure are scaled equally by the load factor.

This analysis technique is applied to the drywell pie slice finite element model, with a reduction in thickness of 0.200 inches (below the design buckling thickness of 0.736") in a local area of 12 x 12 inches in the sandbed region, tapering to the original thickness over an additional 12 inches, located to result in the largest reduction in load factor possible. This location is selected at the point of maximum deflection of the eigenvector shape associated with the lowest buckling load. The theoretical load factor / eigenvalue was reduced by 9.5% from 6.14 to 5.56.

It should be noted that this reduction of 0.200 inches is over a 144 square inch area of the shell while the actual surface area including the tapering of the thickness is 36 x 36 inches or 1,296 square inch area with thicknesses that are below the 0.736 inch buckling design thickness. This additional tapered area and its reduced thicknesses also contributed to the 9.5% reduction in load factor. In addition, to the reported result for the 27% reduction in wall thickness a second buckling analysis was performed for a wall thickness reduction of 13.5% or 0.636 inches over a one square foot area which only reduced the load factor and theoretical buckling stress by 3.9% for the whole drywell located to result in the largest reduction possible. Again, this reduction of 13.5% is only over a 144 square inch area of the shell, the actual surface area including the tapering of the thickness is a 36 x 36 inch or 1,296 square inch area with thicknesses that are below the buckling design thickness. This additional tapered area and its reduced thicknesses also contribute to the 3.9% reduction in load factor stated previously.

Also, cases of the surrounding areas of thickness greater than 0.736 inches are also used to compute the actual buckling values appropriately. Details are provided in the body of the calculation and Appendix B.

Acceptance Criteria - Very Local Wall (2½ Inches In Diameter):

All inspected locations with UT measurements below 0.736 inches have been determined to be in isolated locations less than 2½ inches in diameter.

The acceptance criteria for these measurements confined to an area less than 2 & ½ inches in diameter experiencing primary membrane plus bending stresses is based on ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE-3213.2 and NE-3213.10. In particular NE-3213.10 limits the meridional distance between openings without reinforcement to $2.5\sqrt{Rt}$. Also Paragraph NE-3335.1 only applies to openings in shells that are closer than 2 times their average diameter.

The implication of these paragraphs are that shell failures at these locations from primary stresses produced by design pressure cannot occur provided openings in shells have sufficient reinforcement. The current design pressure of 44 psig for the drywell requires a thickness of 0.479 inches in the sandbed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sandbed region exceed the required pressure thickness by a substantial margin and there are no openings in the sandbed region of the drywell shell that do not contain the required design pressure reinforcement for the design code of record. Therefore, the requirements specified by the referenced code sections in the previous paragraph are not required for the very local wall thickness evaluation presented in the calculation.

The effect of these very local wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load.

To begin the discussion we will describe the buckling of a simply supported cylindrical shell under the influence of lateral external pressure and axial load. As described in chapter 11 of Reference 3.7, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of Sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin walled cylindrical shell both the length and radius would be essentially constants and if the thickness was reduced locally then this reduction would have to be significant and over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This is demonstrated in Reference 3.5 where a 12 x 12 square inch section of the drywell sandbed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell.

Now reviewing the stability analyses provided in both References 3.3 and 3.5 and recognizing that the plate elements in the sandbed region of the model are 3" x 3", it is clear that the circumferential buckling lobes for the drywell are substantially larger than the 2 & ½ inch diameter very local wall areas. This combined with the local reinforcement surrounding these local areas and the spherical shell being close to the constraint provided by the concrete supporting structure indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from Reference 3.5 that a uniform reduction in thickness of 27% over a one square foot area followed by a transition zone would only create a 9.5% reduction in the load factor and theoretical buckling load of the drywell. Although this reduction of 27% is only over a 144 square inch area of the shell, the actual surface area including the transition zone to the 0.736 inch buckling design thickness is a 36 inch x 36 inch or 1,296 square inch area with thicknesses that are below the buckling design thickness. This additional transition zone and its reduced thicknesses also contribute to the 9.5% reduction in load factor stated previously. In addition, to the reported result for the 27% reduction in wall thickness a second buckling analysis was performed for a wall thickness reduction of 13.5% over a one square foot area followed by a transition zone to the 0.736 inch buckling design thickness which only reduced the load factor and theoretical buckling load by 3.9% for the whole drywell located to result in the largest reduction possible. Again, although this reduction of 13.5% is only over a 144 square inch area of the shell, the actual surface area including the transition zone to the buckling design thickness is a 36 inch x 36 inch or 1,296 square inch area with thicknesses that are below the buckling design thickness. This additional transition zone and its reduced thicknesses also contribute to the 3.9% reduction in load factor stated previously. To bring these results into perspective a review of the NDE reports presented in Appendix D indicate there are 20 UT measured areas scattered about the whole sandbed region that have thicknesses less than the 0.736 inch thickness used in Reference 3.3, which if contiguous would cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Therefore, to effectively change the buckling margins on the drywell shell in the sandbed region a uniform reduced thickness would have to cover approximately one square foot of shell area with an additional transition zone from the reduced thickness to the 0.736" design thickness at a location in the shell that is most susceptible to buckling with a reduction in wall thickness greater than 25% based on Reference 3.5. Furthermore, the very local wall areas are centered about the vents which significantly stiffen the shell. This stiffing effect combined with the constraint provided by the concrete supporting structure limits the shell buckling to a point in the shell sandbed region which is located at the midpoint between two vents. Based on the previous statements the 20 UT measured areas below 0.736 inches even if they were contiguous with each other and were at a location in the shell most susceptible to buckling they would not effect significantly the shell buckling response so long as they are less than one square foot based on Reference 3.5. The fact is the very local areas are in locations that are less susceptible to buckling and no two locations are contiguous with each other.

UT EVALUATION BAY #1:

The outside surface of this bay is rough and full of dimples similar to the outside surface of a golf ball. This observation is made by the inspector who located the thinnest areas for the UT examination. This inspection focused on the thinnest areas of the drywell, even if it was very local, i.e., the inspection did not attempt to define a shell thickness suitable for structural evaluation. The shell appears to be relatively uniform in thickness except for a band of corrosion which looks like a "bathtub" ring, located 15 to 20 inches below the vent pipe reinforcement plate, i.e., weld line as shown in Figure 1. (Figure 1 and other like figures presented in this calculation are NOT TO SCALE). The graphical presentation in Figure 1 of measured indications is extracted from Appendix D, Pages 6 to 11. Based on the inspectors observations the bathtub ring is 12 to 18 inches wide and about 75 inches long located in the center of the bay. Beyond the bathtub ring on both sides, the shell appears to be uniform in thickness at a conservative value of 0.800 inches. Above the bathtub ring the shell exhibits no corrosion since the original lead primer on the vent pipe/reinforcement plate is intact. Measurements 14 and 15 confirm that the thickness above the bathtub ring is at 1.154 inches starting at elevation 11'-00". Below the bathtub ring the shell is uniform in thickness where no abrupt changes in thicknesses are present. Thickness measurements below the bathtub ring (Locations 6, 7, 8, 9, 16, 17, 18, 19, 22 and 23) are all above 0.750 inches (See Table 1-b) except location 7 which is very local area.

Bay #1 General Wall (Sandbed Region) Thickness Evaluation

Therefore, taking the average of the UT measured thicknesses of locations 6, 7, 8, 9, 16, 18, 19 and 22 gives a average thickness of 0.816 inches for the shell below the bathtub ring. Based on this a conservative mean thickness of 0.800 inches is estimated to represent the evaluation thickness for this bay outside the bounds of the bathtub ring. Given a uniform thickness of 0.800 inches for these areas of the bay it is concluded that these areas are acceptable based on the thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

Locations 1, 2, 3, 4, 5, 10, 11, 12, 13, 20, and 21 are confined to the bathtub ring as shown in Figure 1. To determine the general shell thickness in the bathtub ring area of this bay the evaluation thicknesses for each of the locations defined above are averaged together. An example of a typical calculation of the general wall thickness defined as the evaluation thickness is presented below for clarity:

$$(\text{AVG Micrometer})_1 = \frac{D_{1-0^0} + D_{1-45^0} + D_{1-90^0} + D_{1-135^0}}{4}$$

Where: $D_{1-0}{}^0$ = Micrometer Depth Reading for location 1 at 0 degrees taken from Page 9 of Appendix D, etc.

$$(\text{AVG Micrometer})_1 = \frac{0.272"+0.204"+0.206"+0.185"}{4} = 0.217"$$

$$T_{(\text{Evaluation})1} = UT_{(\text{Measurement})1} + (\text{AVG Micrometer})_1 - T_{rough}$$

Where: $UT_{(\text{Measurement})1}$ = 0.720" Taken from Appendix D, Page 6, Location 1.

T_{rough} = 0.200" See Design Input 5.1 and Section 6, Acceptance Criteria, General Wall.

$$T_{(\text{Evaluation})1} = 0.720"+0.217"-0.200" = 0.737"$$

Bay 1 AVG Micrometer Calculations
Table 1-a

Location	Azimuth(1)				AVG
	0^0	45^0	90^0	135^0	
1	0.272"	0.204"	0.206"	0.185"	0.217"
2	0.143"	0.133"	0.143"	0.154"	0.143"
3	0.397"	0.316"	-------	0.329"	0.347"
5	0.330"	0.290"	0.304"	0.330"	0.313"
7	0.208	0.281"	0.246"	0.330"	0.266"
11	0.200"	0.211"	0.225"	0.211"	0.212"
12	0.299"	0.316"	0.261"	0.328"	0.301"
21	0.222"	0.202"	0.238"	0.183"	0.211"

Notes: 1. Azimuth data taken from Appendix D, Page 9.

An average value of the evaluation thicknesses presented in Table 1-c for this band is as follows;

Location	Evaluation Thickness
1	0.737"
2	0.659"
3	0.852"
4	0.760"
5	0.823"
10	0.839"
11	0.726"
12	0.825"
13	0.792"
20	0.965"
21	0.737"

Average = 0.792"

An average evaluation thickness of 0.792 inches for the bathtub ring may raise concern given that the bathtub ring is noticeable and that the difference between its average evaluation thickness (0.792 inches) and the average thickness taken for the entire region (0.800 inches) is only 0.008 inches. This results from the fact that average micrometer readings were generally not taken for the remainder of the shell since each reading was greater than 0.736 inches. In reality, the remainder of the shell is much thicker than 0.800 inches. The appropriate evaluation thickness cannot be quantified since no micrometer readings were taken.

Again given that the average evaluation thickness of the shell in the bathtub ring area exceeds the buckling design thickness of 0.736 inches the shell area within the bathtub ring is also acceptable using the results of Reference 3.3.

Bay #1 Local Wall Thickness Evaluation

The individual measured thicknesses must also be evaluated for compliance with the local wall thickness criteria. Table 1-b identifies 23 locations of UT measurements that were selected to represent the thinnest areas, except locations 14 and 15, based on visual examination. These locations are a deliberate attempt to produce a minimum measurement. Locations 14 and 15 were selected to confirm that no corrosion had taken place in the area above the bathtub ring.

Eight locations shown in Table 1-b (1, 2, 3, 5, 7, 11, 12, and 21) have measurements below 0.736 inches. Inspectors observations indicate that these locations were very deep and not more than 1 to 2 inches in diameter. The depth of each of these areas relative to its immediate surroundings was measured at 4 locations around the spot and the average is shown in Table 1-a. Using the general wall thickness acceptance criteria described

earlier, the evaluation thickness for all measurements of very local areas below 0.736 inches were found to be above 0.736 inches except for two locations, 2 and 11, as shown in Table 1-c. Locations 2 and 11 are in the bathtub ring and are about 4 inches apart. This area is characterized as a local area 4 x 4 inches located at about 15 to 20 inches below the vent pipe reinforcement plate with an average thickness of 0.692 inches. This thickness of 0.692 inches is 0.108 inches reduction from the conservative estimate of 0.800 inches evaluation thickness for the entire bay. In order to quantify the effect of this local region and to address structural compliance, the GE study on local effects used (Ref. 3.5).

This study contains an analysis of the drywell shell using the pie slice finite element model, reducing the thickness by 0.100 inches (from 0.736 to 0.636 inches) in an area 12 x 12 inches in the sandbed region located to result in the largest reduction possible. This location is selected at the point of maximum deflection of the eigenvector shape associated with the lowest buckling load. The theoretical buckling load factor was reduced by 3.9% by a 13.5% reduction in wall thickness over a area of 144 square inches of the shell followed by a transition zone of 12 inches all around. This total reduction in thickness has an area of 1296 square inch. As discussed in the methods of analysis buckling of a shell of revolution is based on a half wavelength of a sinusoidal function, these wave lengths are defined as buckling lobes. To substantially effect the buckling load of a given shell geometry the thickness over the surface of the lobe would have to be reduced significantly. Now the area over which the general sandbed shell thickness is reduced to 0.692" or a wall thickness reduction of 6.0% is 16 square inches. Based on these relative reductions in thickness and areas, the effect of this area of reduced thickness on the buckling capacity of the structure is considered negligible. Also based on the location of this area between 12 to 17 inches to the right of the vent centerline and between 22 and 23 inches down from the vent weld line, it is in the area where buckling of the shell is limited due to the stiffening effect of the vent and vent header assembly. This effect can be clearly seen in the buckling analyses presented in References 3.3 and 3.5.

In summary, using a conservative estimate of 0.800 inches for evaluation thickness for the entire bay and the presence of a bathtub ring with an evaluation thickness of 0.792 inches plus the acceptance of a local area of 4 x 4 inches based on the GE study, it is concluded that the bay is acceptable.

Bay # 1 UT Data
Table 1-b

Location	D-Meter UT Measurement (inches)	Appendix D Page Reference	Average Micrometer (See Table 1-a) (inches)
1	0.720	6	0.217
2	0.716	6	0.143
3	0.705	6	0.347
4	0.760	6	---
5	0.710	6	0.313
6	0.760	6	---
7	0.700	6	0.266
8	0.805	6	---
9	0.805	6	---
10	0.839	8	---
11	0.714	8	0.212
12	0.724	8	0.301
13	0.792	8	---
14	1.147	8	---
15	1.156	8	---
16	0.796	10	---
17	0.860	10	---
18	0.917	10	---
19	0.890	10	---
20	0.965	10	---
21	0.726	10	0.211
22	0.852	10	---
23	0.850	10	---

Summary Of Measurements Below 0.7
Table 1-c

Location	UT Measurement (1)	AVG Micrometer (2)	Mean Depth/Valley (3)	T (Evaluation) (4)=(1)+(2)-(3)	Remarks
1	0.720"	0.217"	0.200"	0.737"	Acceptable
2	0.716"	0.143"	0.200"	0.659"	Acceptable
3	0.705"	0.347"	0.200"	0.852"	Acceptable
5	0.710"	0.313"	0.200"	0.823"	Acceptable
7	0.700"	0.266"	0.200"	0.766"	Acceptable
11	0.714"	0.212"	0.200"	0.726"	Acceptable
12	0.724"	0.301"	0.200"	0.825"	Acceptable
21	0.726"	0.211"	0.200"	0.737"	Acceptable

BAY #1 DATA

NOTES:

1. All "Location" measurements from intersection of the DW shell and vent collar fillet welds.

2. Pit depts are average of four readings taken at 0/45°/90°/135° within 1" band surrounding ground spots. Only measured where remaining wall thk. was below 0.736".

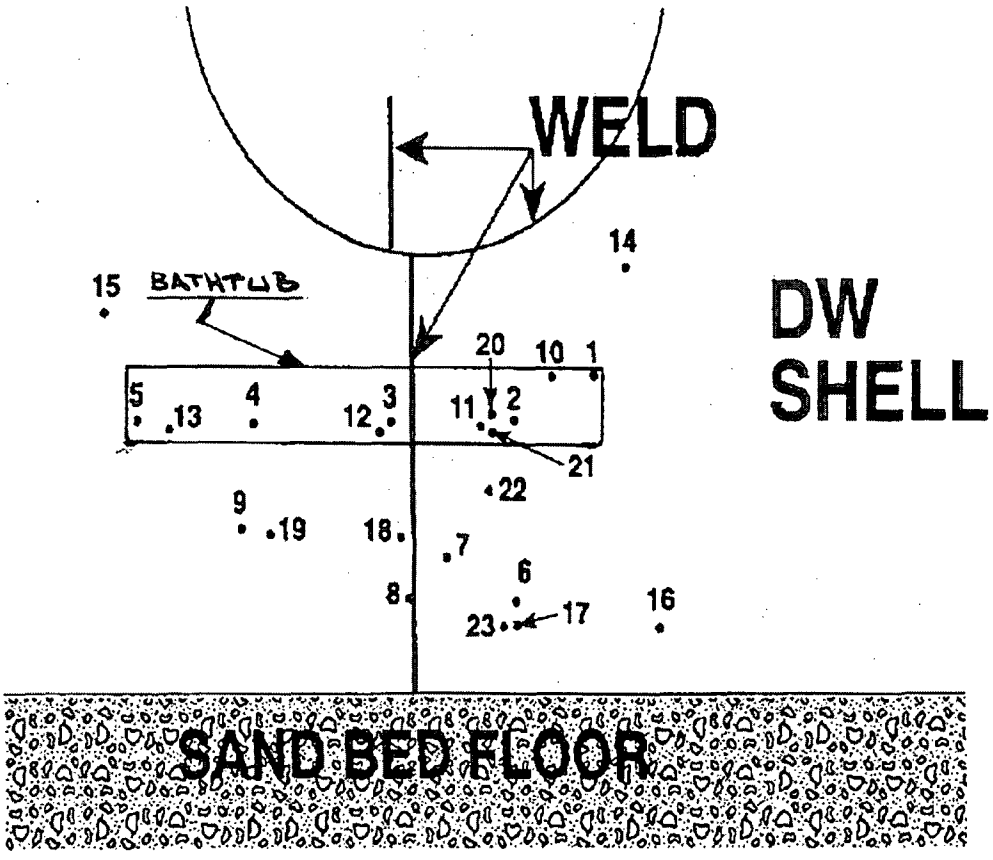


FIGURE (1)

UT EVALUATION BAY #3:

The outside surface of this bay is rough; similar to bay one, full of dimples comparable to the outside surface of golf ball. This observation is made by the inspector who located the thinnest areas for the UT examination. The shell appears to be relatively uniform in thickness except for a bathtub ring 8 to 10 inches wide approximately 6 inches below the vent header reinforcement plate. The upper portion of the shell beyond the band exhibits no corrosion where the original red lead primer is still intact. Eight locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 3). These locations are a deliberate attempt to produce a minimum measurement. Table 3 shows measurements taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches.

Bay #3 General Wall (SandBed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 3 equal to 0.868 inches, a conservative mean evaluation thickness of 0.850 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using results of Reference 3.3.

Bay # 3 UT Data
Table 3

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.795	12	---
2	1.000	12	---
3	0.857	12	---
4	0.898	12	---
5	0.823	12	---
6	0.968	12	---
7	0.826	12	---
8	0.780	12	---

BAY #3 DATA

NOTES:

1. All "Location" measurements from intersection of the DW shell and vent collar fillet welds.

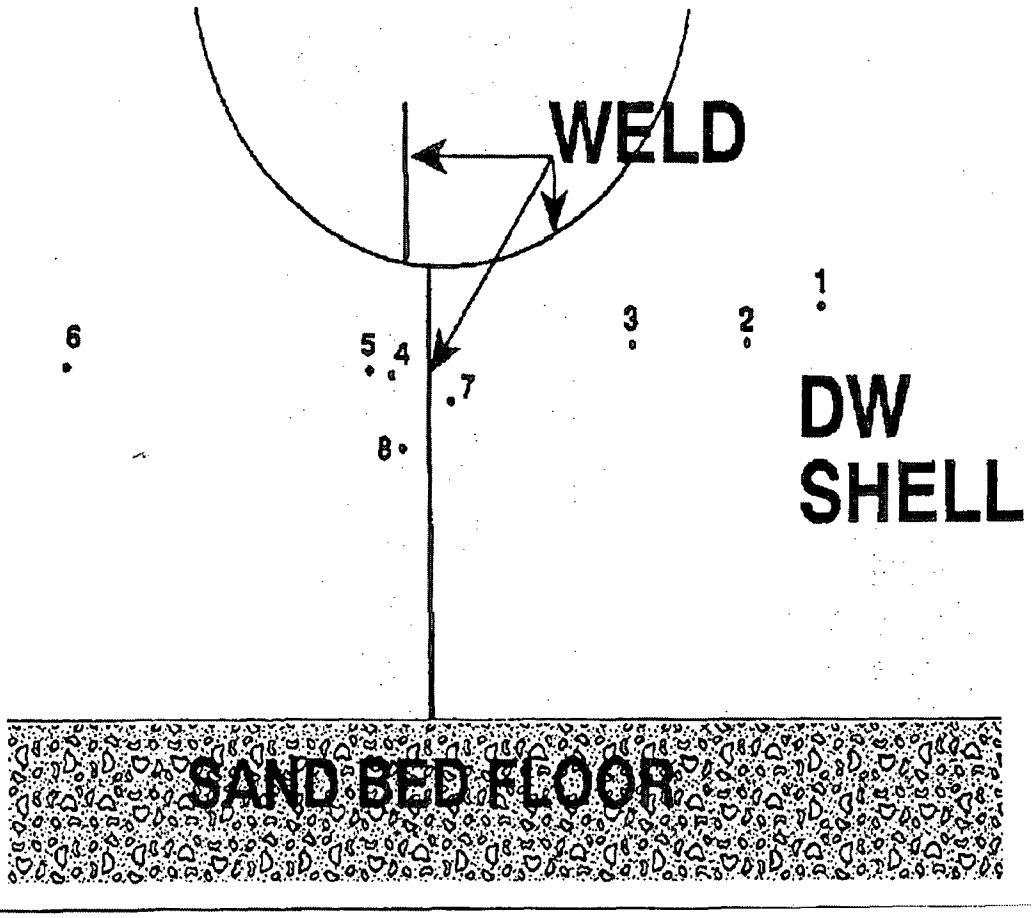


FIGURE (3)

UT EVALUATION BAY #5:

The outside surface of this bay is rough and very similar to bay 3 except that the local areas are clustered at the junction of bays 3 and 5, at about 30 inches above the floor. The shell surface is full of dimples comparable to the outside surface of a golf ball. This observation is made by the inspector who located the thinnest areas for the UT examination. The shell appears to be relatively uniform in thickness. Eight locations were selected to represent the thinnest areas based on the visual observations of the shell surface (see Fig. 5). These locations are a deliberate attempt to produce a minimum measurement. Table 5 shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches.

Bay #5 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 5 equal to 0.986 inches, a conservative mean evaluation thickness of 0.950 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

Bay # 5 UT Data
Table 5

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.970	15	---
2	1.040	15	---
3	1.020	15	---
4	0.910	15	---
5	0.890	15	---
6	1.060	15	---
7	0.990	15	---
8	1.010	15	---

BAY #5 DATA

NOTES:

1. In this bay DW shell (butt) weld is about 8" to the right of C/L of vent tube. Therefore - all measurements were taken from a line drawn on shell which approx. coincide with vent tube C/L.

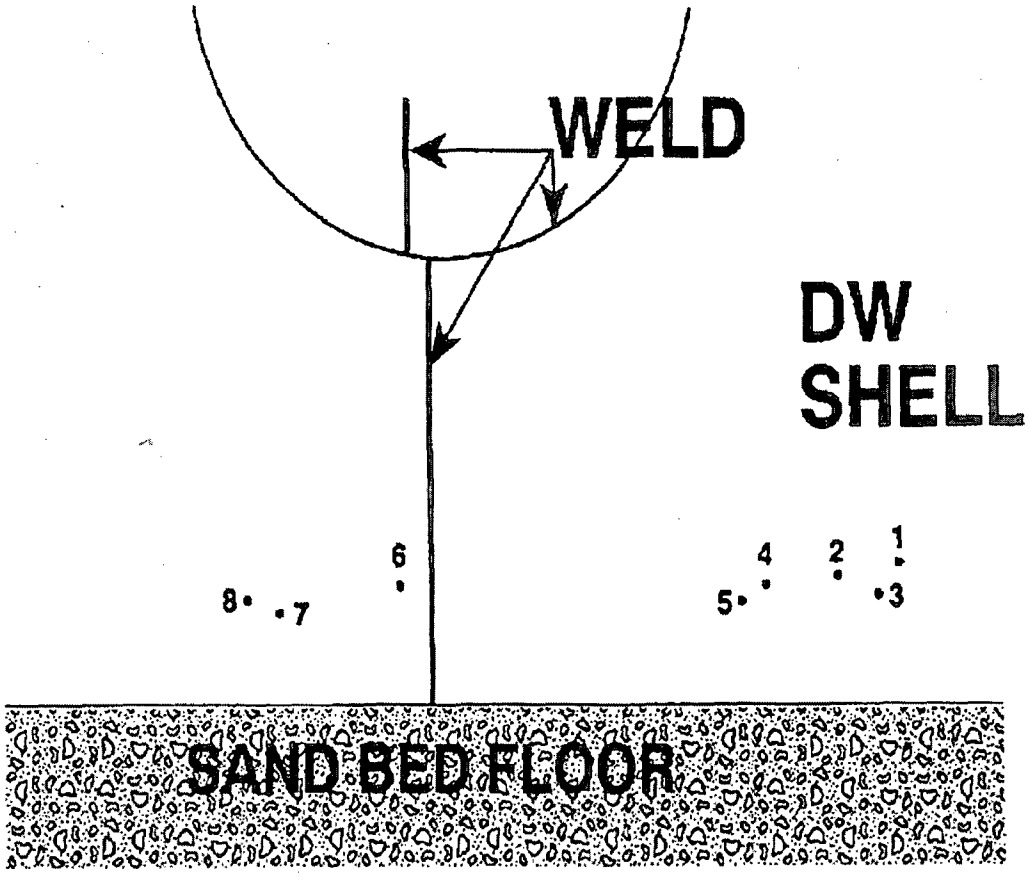


FIGURE (5)

UT EVALUATION BAY #7:

The observation of the drywell surface for this bay showed uniform dimples in the corroded area, but they are shallow compared to those in bay 1. The bathtub ring seen in the other bays was not very prominent in this bay. This observation is made by the inspector who located the thinnest areas for the UT examination. The shell appears to be relatively uniform in thickness. Seven locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 7). These locations are a deliberate attempt to produce a minimum measurement. Table 7 shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches.

Bay #7 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 7 equal to 1.001, a mean evaluation thickness of 1.00 inch is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

Bay # 7 UT Data
Table 7

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.920	19	---
2	1.016	19	---
3	0.954	19	---
4	1.040	19	---
5	1.030	19	---
6	1.045	19	---
7	1.000	19	---

BAY #7 DATA

NOTES:

1. All measurements from the intersection of DW shell (butt) and vent collar (fillet) welds.

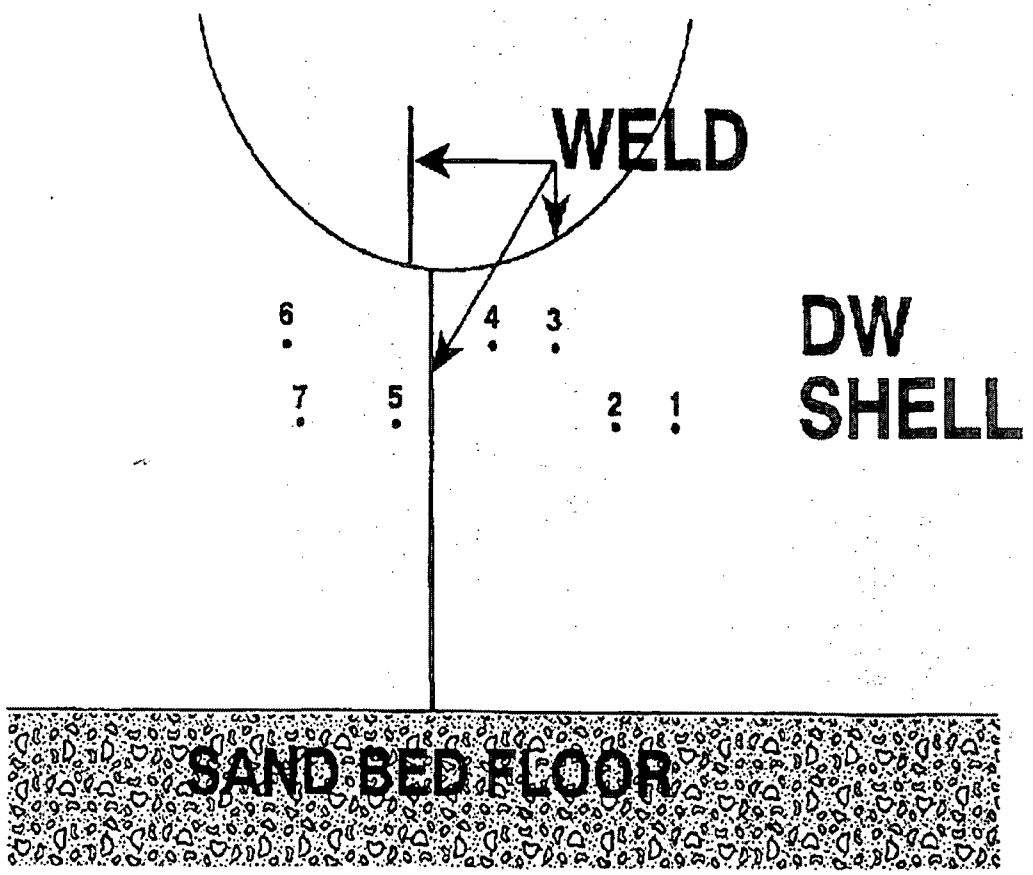


FIGURE (7)

UT EVALUATION BAY #9:

The observation of the drywell shell for this bay was very similar to bay 7 except that the bathtub ring was more evident in this bay. The shell appears to be relatively uniform in thickness except for a bathtub ring 6 to 9 inches wide approximately 6 to 8 inches below the vent header reinforcement plate. The upper portion of the shell beyond the band exhibits no corrosion where the original red lead primer is still intact. Ten locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 9). These locations are a deliberate attempt to produce a minimum measurement. Table 9 shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches.

Bay #9 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 9 equal to 0.915, a conservative mean evaluation thickness of 0.900 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

Bay # 9 UT Data
Table 9

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.960	20	---
2	0.940	20	---
3	0.994	20	---
4	1.020	20	---
5	0.985	20	---
6	0.820	20	---
7	0.825	20	---
8	0.791	20	---
9	0.832	20	---
10	0.980	20	---

BAY #9 DATA

NOTES:

1. All measurements from intersection of the DW shell (butt) and vent collar (fillet) welds.

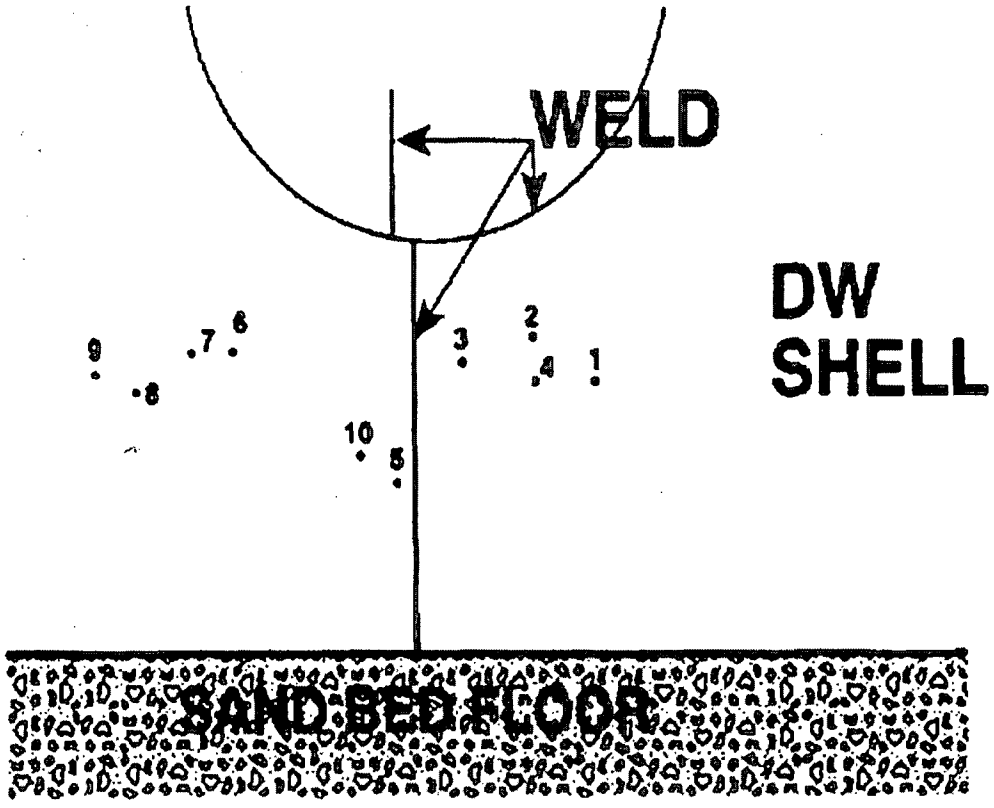


FIGURE (9)

UT EVALUATION BAY #11:

The outside surface of this bay is rough, similar to bay 1, full of uniform dimples comparable to the outside surface of a golf ball. The shell appears to be relatively uniform in thickness except for local areas at the upper right corner of Figure 11, located at about 10 to 12 inches below the vent pipe reinforcement plate.

Eight locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 11). These locations are a deliberate attempt to produce a minimum measurement. Table 11-a shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches, except one location. Location 1 as shown in Table 11-a, has a reading below 0.736 inches. Inspectors observations indicate that this location was very deep and not more than 1 to 2 inches in diameter. The depth of area relative to its immediate surrounds was measured at 4 locations around the spot and the average is shown in Table 11-a. As described in Section 6, Methods of Analysis, Very Local Wall Acceptance Criteria, areas of reduced thickness equal to or less than 2 & ½ inches are too small to reduce the shell critical buckling load. This combined with the location of the very local indication near the vent reinforcement (See Page 22 of Appendix D) indicates that this area would have a negligible effect on the shell buckling response.

Bay #11 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 11-a equal to 0.792 inches, a conservative mean evaluation thickness of 0.790 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

The calculation of the average depth for Bay 11, Location 1 is as follows:

$$(\text{AVG Micrometer})_1 = \frac{D_{1-0^0} + D_{1-45^0} + D_{1-90^0} + D_{1-135^0}}{4}$$

Where: $D_{1-0}{}^0$ = Micrometer Depth Reading for location 1 at 0 degrees taken from Page 26 of Appendix D, etc.

$$(\text{AVG Micrometer})_1 = \frac{0.289"+0.338"+0.157"+0.200"}{4} = 0.246"$$

Bay # 11 UT Data
Table 11-a

Location	UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.705	22	0.246
2	0.770	22	---
3	0.832	22	---
4	0.755	22	---
5	0.831	22	---
6	0.800	22	---
7	0.831	22	---
8	0.815	22	---

Summary of Measurements Below 0.736 Inches
Table 11-b

Location	UT Measurement (1)	AVG Micrometer (2)	Mean Depth/Valley (3)	T (Evaluation) (4)=(1)+(2)-(3)	Remarks
1	0.705"	0.246"	0.200"	0.751"	Acceptable

BAY #11 DATA

NOTES:

1. All measurements from intersection of the DW shell (butt) and vent collar (fillet) welds.
2. Pit depths are average of four readings taken at 0/45°/90°/135° within 1" band surrounding the ground spots. This measurement was only taken when wall thickness was below 0.736".

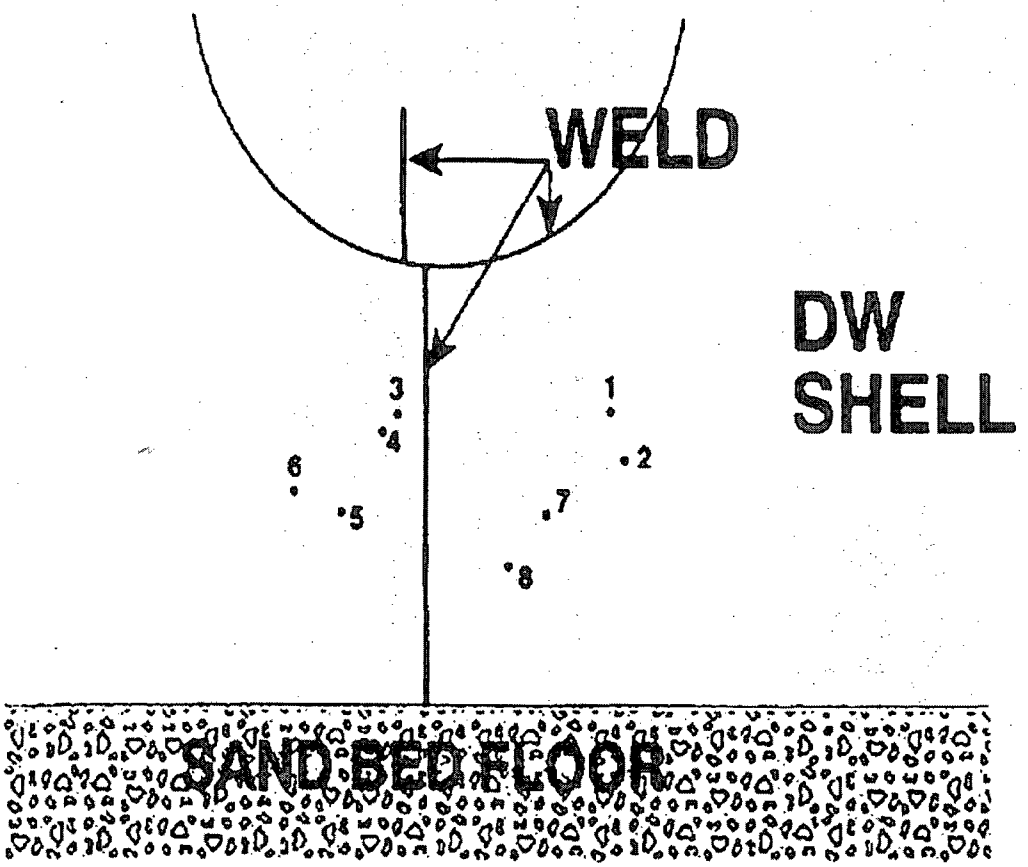


FIGURE (11)

UT EVALUATION BAY #13:

The outside surface of this bay is rough and full of dimples similar to bay 1 as shown in Appendix C. This observation is made by the inspector who located the thinnest areas in deep valleys thereby biasing the remaining wall measurements to the conservative side. This inspection focused on the thinnest areas, even if very local, i.e., the inspection did not attempt to define a shell thickness suitable for structural evaluation. The variation in shell thickness is greater in this bay than in the other bays. The bathtub ring below the vent pipe reinforcement plate was less prominent than was seen in other bays. The corroded areas are about 12 to 18 inches in diameter and are at 12 inches apart, located in the middle of the sandbed. Beyond the corroded areas on both sides, the shell appears to be uniform in thickness at a conservative value of 0.800". Near the vent pipe and reinforcement plate the shell exhibits no corrosion since the original lead primer on the vent pipe/reinforcement plate is intact. Measurement 20 confirms that the thickness above the bathtub ring is at 1.154 inches. Below the bathtub ring the shell appears to be fairly uniform in thickness where no abrupt changes in thickness are present. Thickness measurements below the bathtub ring (Locations 3, 4, 9, 12, 13, 16, 17, 18, and 19) are all 0.800 inches or better (See Table 13-b).

Bay #13 General Wall (Sandbed Region) Thickness Evaluation

Therefore, given an average of the UT measurements of the locations below the bathtub ring is equal to 0.884 inches, a conservative mean thickness of 0.800 inches is estimated to represent the evaluation thickness for areas of shell in this bay outside the bathtub ring. Given a uniform thickness of 0.800 inches for these areas of the bay it is concluded that these areas are acceptable based on the thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

Locations 5, 6, 7, 8, 10, 11, 14, and 15 are confined to the bathtub ring as shown in Figure 13. To determine the general shell thickness in the bathtub ring area of this bay the evaluation thicknesses (See Table 13-c) for each of the locations defined above are averaged together. An example of a typical calculation of the general wall thickness defined as the evaluation thickness is presented below for clarity:

$$(\text{AVG Micrometer})_5 = \frac{D_{5-0^0} + D_{5-45^0} + D_{5-90^0} + D_{5-135^0}}{4}$$

Where: $D_{5-0}{}^0$ = Micrometer Depth Reading for Bay 13, location 5 at 0 degrees taken from Page 33 of Appendix D, etc.

$$(\text{AVG Micrometer})_5 = \frac{0.150"+0.193"+0.230"+0.298"}{4} = 0.217"$$

$$T_{(\text{Evaluation})5} = UT_{(\text{Measurement})5} + (\text{AVG Micrometer})_5 - T_{rough}$$

Where: $UT_{(\text{Measurement})5}$ = 0.718" Taken from Appendix D, Page 28, Location 5

T_{rough} = 0.200" See Design Input 5.1 and Section 6, Acceptance Criteria, General Wall.

$$T_{(\text{Evaluation})5} = 0.718"+0.217"-0.200" = 0.735"$$

Bay 13 AVG Micrometer Calculations
Table 13-a

Location	Azimuth[1]				AVG
	0^0	45^0	90^0	135^0	
1	0.330"	0.382"	0.346"	0.346"	0.351"
2	0.312"	0.377"	0.360"	0.393"	0.360"
5	0.150"	0.193"	0.230"	0.298"	0.217"
6	0.327"	0.339"	0.290"	0.247"	0.301"
7	0.241	0.279"	0.260"	0.239"	0.255"
8	0.324"	0.245"	0.262"	0.279"	0.278"
10	0.186"	0.173"	0.255"	0.229"	0.211"
11	0.240"	0.231"	0.271"	0.283"	0.256"
15	0.288"	0.277"	0.239"	0.288"	0.273"

Notes: 1. Azimuth data taken from Appendix D, Page 33.

An average value of the evaluation thicknesses presented in Table 13-c for this band is as follows;

Location	Evaluation Thickness
5	0.735"
6	0.756"
7	0.675"
8	0.796"
10	0.739"
11	0.741"
12	0.885"
14	0.868"
15	0.756"
16	0.829"
	Average = 0.778"

The inspector suspected that some of the above locations in the bathtub ring were over ground. Subsequent locations with suffix A, e.g. 5A, 6A, were located close to the spots in question and were ground carefully to remove the minimum amount of metal but adequate enough for UT examination as shown in Table 13-b. The results indicate that all subsequent measurements were above 0.736 inches. The average micrometer measurements taken for these locations confirm the depth measurements at these locations. In spite of the fact that the original measurements were taken at heavily ground locations they are the ones used in the evaluation.

Again given that the average evaluation thickness of the shell in the bathtub ring area exceeds the buckling design thickness of 0.736 inches the shell area within the bathtub ring is also acceptable based on the results of Reference 3.3.

Bay #13 Local Wall Thickness Evaluation

The individual measurements must also be evaluated for compliance with the local wall thickness criteria. Table 13-b identifies 20 locations of UT measurements that were selected to represent the thinnest areas, except location 20, based on visual examination. These locations are a deliberate attempt to produce a minimum measurement. Location 20 was selected to confirm that no corrosion had taken place in the area above the bathtub ring.

Nine locations shown in Table 13-b (1, 2, 5, 6, 7, 8, 10, 11, and 15) have measurements below 0.736 inches. Inspectors observations indicate that these locations were very deep, overly ground, and not more than 1 to 2 inches in diameters. The depth of each of these areas relative to its immediate surroundings was measured at 4 locations around the spot and the average is shown in Table 13-a. Using the general wall thickness acceptance criteria described earlier, the evaluation thickness for all measurements below 0.736 inches were found to be above 0.736 inches except for two locations, 5 and 7, as shown in Table 13-b. In addition, subsequent measurements close to the locations identified above, were taken and they were all above 0.736 inches. Locations 5 and 7 are in the bathtub ring and are about 30 inches apart. These locations are characterized as local areas located at about 15 to 20 inches below the vent pipe reinforcement plate with an

evaluation thicknesses of 0.735 inches and 0.673 inches. The location 5 is near to location 14 for an average value of 0.801 inches and therefore acceptable. Location 7 could conservatively exist over an area of 6 x 6 inches for a thickness of 0.673 inches. This thickness of 0.673 inches is a full 0.127 inches reduction from the conservative estimate of 0.800 inches evaluation thickness for the entire bay. In order to quantify the effect of this local region and to address structural compliance, the GE study on local effects is used (Ref. 3.5).

The theoretical buckling load factor was reduced by 3.9% by a 13.5% reduction in wall thickness over an area of 144 square inches of the shell followed by a transition zone of 12 inches all around. This total reduction in thickness has an area of 1296 square inch. As discussed in the methods of analysis buckling of a shell of revolution is based on a half wave length of a sinusoidal function these wave lengths are defined as buckling lobes. To substantially effect the buckling load of a given shell geometry the thickness over the surface of a lobe would have to be reduced significantly. Now the area over which the general sandbed shell thickness is reduced to 0.673" or a wall thickness reduction of 8% is 36 square inches. Based on these relative reductions in thickness and area, the effect of this area of reduced thickness on the buckling capacity of the structure is considered negligible. Also, based on the location of this area between 20 to 26 inches to the left of the vent centerline and between 14 to 20 inches down from the vent weld it is in the area where buckling of the shell is limited due to the stiffening effect of the vent and vent header assembly. This effect can be clearly seen in the buckling analyses presented in References 3.3 and 3.5.

In summary, using a conservative estimate of 0.800 inches for evaluation thickness for the entire bay and the presence of a bathtub ring with a evaluation thickness of 0.778 inches plus the acceptance of a local general shell reduced thickness area of 6 x 6 inches found to be acceptable based on the GE studies, it is concluded that the bay is acceptable.

Bay # 13 UT Data
Table 13-b

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer(1) (Table 13-a) (inches)
1/1A	0.672/0.890	28/30	0.351
2/2A	0.722/0.943	28/30	0.360
3	0.941	28	---
4	0.915	28	---
5/5A	0.718/0.851	28/30	0.217
6/6A	0.655/0.976	28/30	0.301
7/7A	0.618/0.752	28/30	0.255
8/8A	0.718/0.900	28/30	0.278
9	0.924	28	---
10/10A	0.728/0.810	28/30	0.211
11/11A	0.685/0.854	28/30	0.256
12	0.885	28	---
13	0.932	28	---
14	0.868	28	---
15/15A	0.683/0.859	28/30	0.273
16	0.829	28	---
17	0.807	28	---
18	0.825	28	---
19	0.912	28	---
20	1.170	28	---

(1) (1) Average values provided in this column are for locations 1, 2, 5, etc.

(1) (without suffix A) and not for 1A, 2A, 5A, etc. The values are compiled in Table 13-a

Summary of Measurements Below 0.736 Inches
Table 13-c

Location	UT Measurement (1)	AVG Micrometer (2)	Mean Depth/Valley (3)	T (Evaluation) (4)=(1)+(2)-(3)	Remarks
1	0.672"	0.351"	0.200"	0.823"	Acceptable
2	0.722"	0.360"	0.200"	0.882"	Acceptable
5	0.718"	0.217"	0.200"	0.735"	Acceptable
6	0.655"	0.301"	0.200"	0.756"	Acceptable
7	0.618"	0.255"	0.200"	0.673"	Acceptable
8	0.718"	0.278"	0.200"	0.796"	Acceptable
10	0.728"	0.211"	0.200"	0.739"	Acceptable
11	0.685"	0.256"	0.200"	0.741"	Acceptable
15	0.683"	0.273"	0.200"	0.756"	Acceptable

BAY #13 DATA

NOTES:

1. All measurements from intersection of the DW shell (butt) and vent collar (fillet) welds.
2. Spots with suffix (e.g. 1A or 2A) were located close to the spots in question and were ground carefully to remove minimum amount of metal but adequate enough for UT.
3. Pit depths are average of four readings taken at 0/45°/90°/135° within 1" distance around ground spot. Taken only where remaining wall showed below 0.736".

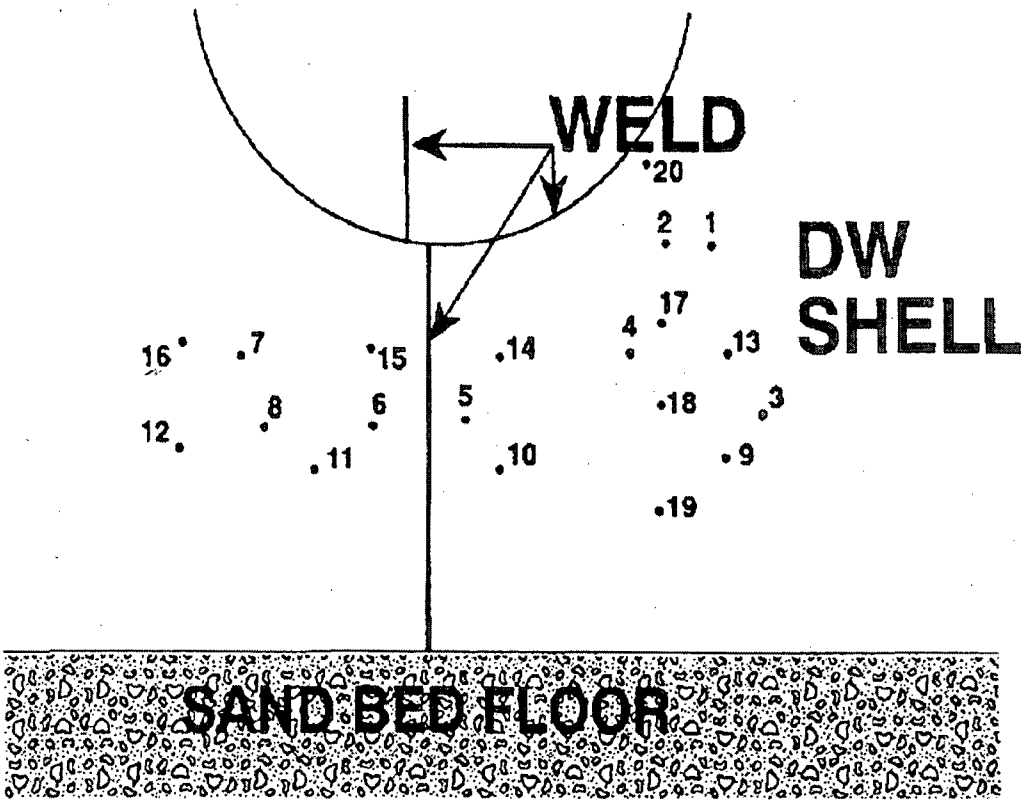


Figure (13)

UT EVALUATION BAY #15:

The outside surface of this bay is rough, similar to bay 1, full of uniform dimples comparable to the outside surface of golf ball (Appendix C). The bathtub ring seen in the other bays, was not very prominent in this bay. This observation is made by the inspector who located the thinnest areas for the UT examination. The upper portion of the shell beyond the ring exhibits no corrosion where the original red lead primer is still intact. The shell appears to be relatively uniform in thickness.

Eleven locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 15). These locations are a deliberate attempt to produce a minimum measurement. Table 15-a shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches, except one location. Location 9 as shown in Table 15-a, has a reading below 0.736 inches. Inspectors observations indicate that this location was very deep and not more than 1 to 2 inches in diameter. The depth of area relative to its immediate surrounding was measured at 4 locations around the spot and the average is shown in Table 15-a. As described in Section 6, Methods of Analysis, Very Local Wall Acceptance Criteria, areas of reduced thickness equal to or less than 2 & ½ inches are too small to reduce the shell critical buckling load. This combined with the location of the very local indication near the vent reinforcement (See Page 34 of Appendix D) indicates that this area would have a negligible effect on the shell buckling response.

Bay #15 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 15-a is equal to 0.816 inches, a conservative mean evaluation thickness of 0.800 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

The calculation of the average depth for Bay 15, Location 9 is as follows:

$$(\text{AVG Micrometer})_9 = \frac{D_{9-0^0} + D_{9-45^0} + D_{9-90^0} + D_{9-135^0}}{4}$$

Where: $D_{9\text{-}0}{}^0$ = Micrometer Depth Reading for location 9 at 0 degrees taken from Page 35 of Appendix D, etc.

$$(\text{AVG Micrometer})_1 = \frac{0.356"+0.350"+0.359"+0.282"}{4} = 0.337"$$

Bay # 15 UT Data
Table 15-a

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.786	34	---
2	0.829	34	---
3	0.932	34	---
4	0.795	34	---
5	0.850	34	---
6	0.794	34	---
7	0.808	34	---
8	0.770	34	---
9	0.722	34	0.337
10	0.860	34	---
11	0.825	34	---

Summary of Measurements Below 0.736 Inches
Table 15-b

Location	UT Measurement (1)	AVG Micrometer (2)	Mean Depth/Valley (3)	T (Evaluation) (4)=(1)+(2)-(3)	Remarks
9	0.722"	0.337"	0.200"	0.859"	Acceptable

BAY #15 DATA

NOTES:

1. All measurements from intersection of the DW shell and vent collar (fillet) welds.

2. Pit depths are average of four readings taken at 0/45°/90°/135° within 1" distance around ground spots. Taken only when remaining wall thickness shown below 0.736".

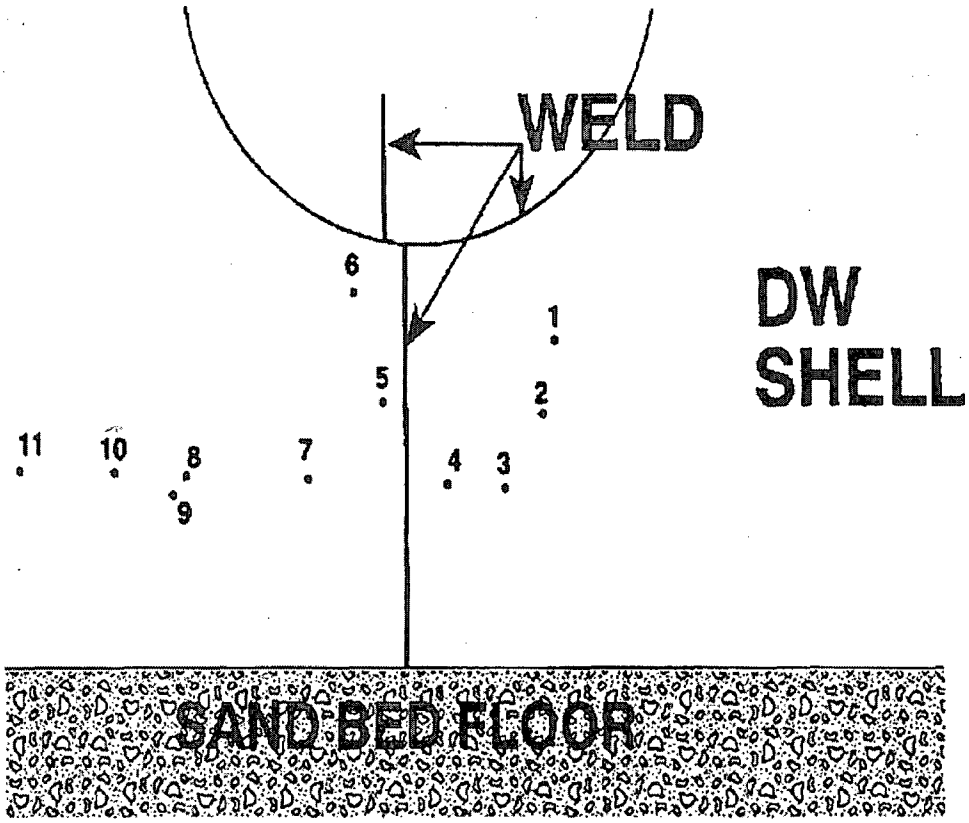


FIGURE (15)

UT EVALUATION BAY #17:

The outside surface of this bay is rough, similar to bay 1, full of uniform dimples comparable to the outside surface of golf ball. The shell appears to be relatively uniform in thickness except for a band 8 to 10 inches wide approximately 6 inches below the vent header reinforcement plate. The upper portion of the shell beyond the band exhibits no corrosion where the original red lead primer is still intact.

Eleven locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 17). These locations are a deliberate attempt to produce a minimum measurement. Table 17-a shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches, except one location. Location 9 as shown in Table 17-a, has a reading below 0.736 inches. Inspectors observations indicate that this location is very deep and not more than 1 to 2 inches in diameter. The depth of area relative to its immediate surroundings was measured at 4 locations around the spot and the average is shown in Table 17-a. As described in Section 6, Methods of Analysis, Very Local Wall Acceptance Criteria, areas of reduced thickness equal to or less than 2 & ½ inches are too small to reduce the shell critical buckling load. This combined with the location of the very local indication near the vent reinforcement (See Page 38 of Appendix D) indicates that this area would have a negligible effect on the shell buckling response.

Bay #17 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 17-a is equal to 0.918 inches, a conservative mean evaluation thickness of 0.900 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

The calculation of the average depth for Bay 17, Location 9 is as follows:

$$(\text{AVG Micrometer})_9 = \frac{D_{9-0^0} + D_{9-45^0} + D_{9-90^0} + D_{9-135^0}}{4}$$

Where: $D_{9\text{-}0}{}^0$ = Micrometer Depth Reading for location 9 at 0 degrees taken from Page 40 of Appendix D, etc.

$$(\text{AVG Micrometer})_1 = \frac{0.368"+0.407"+0.289"+0.342"}{4} = 0.351"$$

Bay # 17 UT Data
Table 17-a

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.916	39	---
2	1.150	39	---
3	0.898	39	---
4	0.951	39	---
5	0.913	39	---
6	0.992	39	---
7	0.970	39	---
8	0.990	39	---
9	0.720	38	0.351
10	0.830	38	---
11	0.770	38	---

Summary of Measurements Below 0.736 Inches

Table 17-b

Location	UT Measurement (1)	AVG Micrometer (2)	Mean Depth/Valley (3)	T (Evaluation) (4)=(1)+(2)-(3)	Remarks
9	0.720"	0.351"	0.200"	0.871"	Acceptable

BAY #17 DATA

NOTES:

1. All measurements from intersection of the DW (butt) shell and vent collar (fillet) welds.

2. Pit depths are average of four readings taken at 0/45°/90°/135° within 1" distance around ground spots. Taken only when remaining wall thickness was below 0.738".

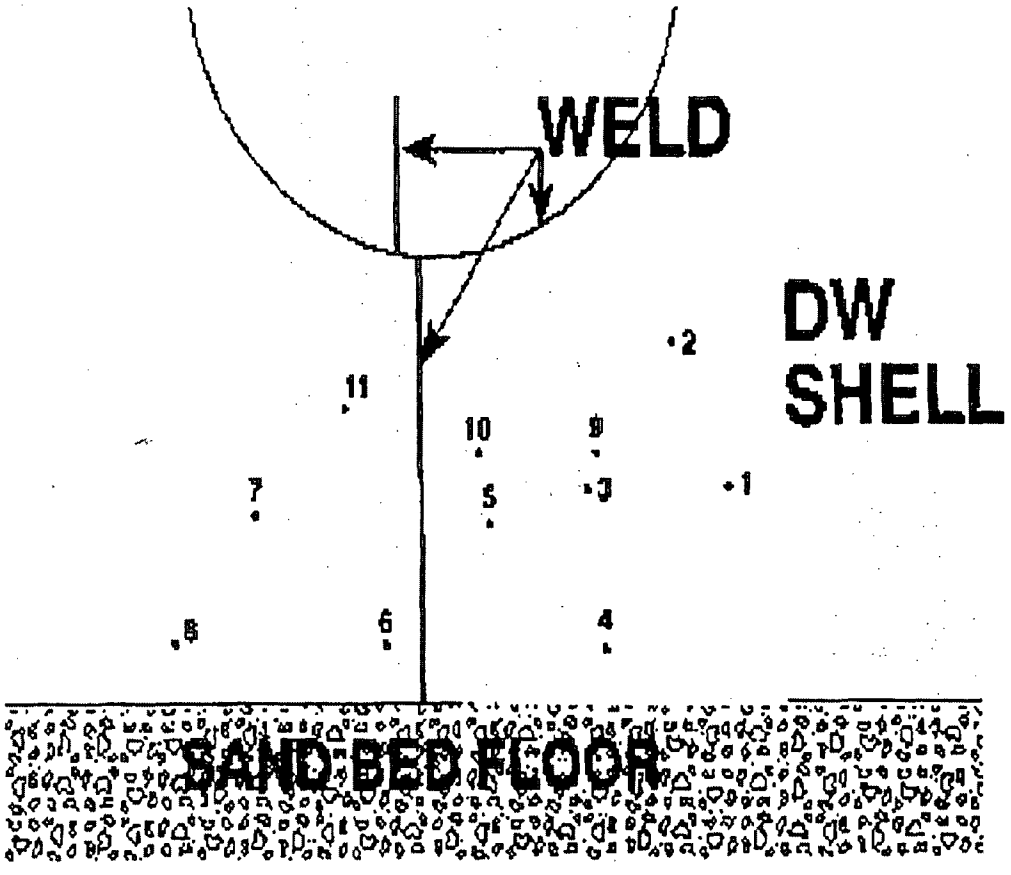


FIGURE (17)

UT EVALUATION BAY #19:

The outside surface of this bay is rough and very similar to bay 17. Locations 1 through 7 as shown in Table 19, were ground carefully to minimize loss of good metal. The shell surface is full of dimples comparable to the outside surface of a golf ball. This observation is made by the inspector who located the thinnest areas for the UT examination. The shell appears to be relatively uniform in thickness. Ten locations were selected to represent the thinnest areas based on the visual observations of the shell surface (Fig. 19). These locations are a deliberate attempt to produce a minimum measurement. Table 19 shows readings taken to measure the thicknesses of the drywell shell using a D-meter. The results indicate that all of the areas have thickness greater than the 0.736 inches.

Bay #19 General Wall (Sandbed Region) Thickness Evaluation

Given an average of the UT measurements presented in Table 19 is equal to 0.885 inches, a conservative mean evaluation thickness of 0.850 inches is estimated for this bay. Therefore, it is concluded that the bay is acceptable based on the bay evaluation thickness exceeding the buckling design thickness for the sandbed region of 0.736 inches using the results of Reference 3.3.

Bay # 19 UT Data
Table 19

Location	D-Meter UT Measurement (inches)	Appendix D Page Ref.	Average Micrometer (inches)
1	0.932	44	---
2	0.924	44	---
3	0.955	44	---
4	0.940	44	---
5	0.950	44	---
6	0.860	44	---
7	0.969	44	---
8	0.753	43	---
9	0.776	43	---
10	0.790	43	---

BAY #19 DATA

NOTES:

1. All measurements from intersection of the DW shell (butt) and vent collar (fillet) welds.

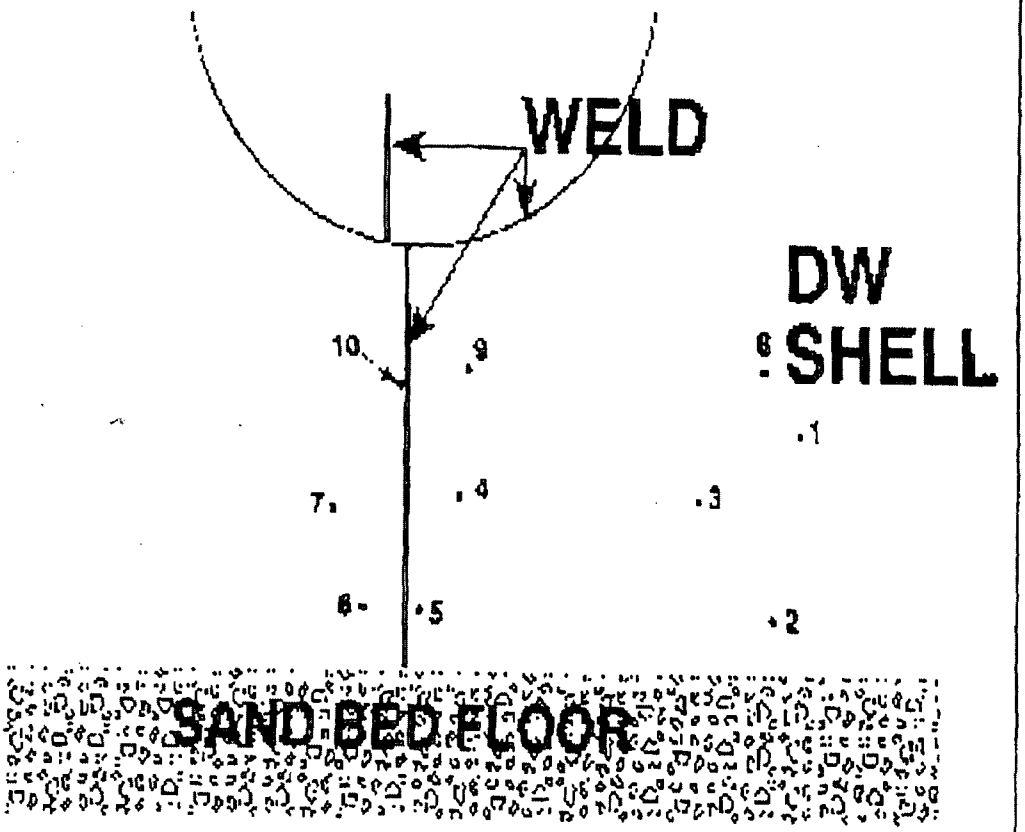


FIGURE (19)

Appendix A: Summary Of Measurements Of Impressions Taken From Bay #13 (3 pages total)

The purpose of this appendix is to characterize the depth of typical uniform dimples on the shell surface. This depth is used in acceptance criteria to quantify the evaluation thickness for an area where the micrometer readings are available.

Two locations in bay 13 were selected since bay 13 is the roughest bay. Impressions of drywell shell surface using DMR_503 Epoxy Replication Putty manufactured by Dyna Mold Inc were made. These impressions were about 10 inches in diameter and about 1 inch thick. The UT locations 7 and 10 in bay 13 were identified in each of these impression as the reference points. This is a positive impression of the drywell shell surface. The depth of the typical dimples were measured as follows;

READING (Location)	DEPTH #10 (inches)	DEPTH #7 inches)
1	0.150	0.075
2	0.000	0.110
3	0.200	0.135
4	0.140	0.200
5	0.150	0.000
6	0.040	0.000
7	0.150	0.170
8	0.010	0.205
9	0.134	-----
10	0.145	0.145
11	0.118	0.064
12	0.105	0.200
13	0.125	0.045
14	0.200	0.180
15	0.135	0.105
16	0.100	-----
17	0.175	0.035
18	0.175	0.015
19	0.155	0.190
20	0.175	0.055
21	0.175	0.305
22	-----	0.135

Location #10:

Mean Value	=	0.131
Standard Deviation	=	0.055
Mean Value + One S.D.	=	0.186

Location #7:

Mean Value	=	0.118
Standard Deviation	=	0.082
Mean Value + One S.D.	=	0.200

Therefore, a value of 0.200 inches was used as the depth of uniform dimples for the entire outside surface of the drywell in the sandbed region.

Appendix B: Buckling Capacity Evaluation For Varying Uniform Thickness Through The Whole Sandbed Region Of The Drywell (5 pages total)

Based Upon GE Buckling Analysis (Reference 3.3)

Note: Tables on sheets 50 to 53 are not used in this calculation and are provided for historical purpose only from Rev. 0.

CALCULATION OF BUCKLING MARGIN - REFUELING CASE, NO SAND - GE OYCR1S&T - UNIFORM THICKNESS t=0.736 Inch

ITEM	PARAMETER	UNITS	VALUE	LOAD FACTOR
	*** DRYWELL GEOMETRY AND MATERIALS			
1	Sphere Radius, R	(in.)	420	
2	Sphere Thickness, t	(in.)	0.736	
3	Material Yield Strength, Sy	(ksi)	38	
4	Material Modolus of Elasticity, E	(ksi)	29600	
5	Factor of Safety, FS		2	
	*** BUCKLING ANALYSIS RESULTS			
6	Theoretical Elastic Instability Stress, Ste	(ksi)	46.590	6.140
	***STRESS ANALYSIS RESULTS			
7	Applied Meridional Compressive Stress, Sm	(ksi)	7.588	5.588
8	Applied Circumferential Tensile Stress, Sc	(ksi)	4.510	3.300
	*** CAPACITY REDUCTION FACTOR CALCULATION			
9	Capacity Reduction Factor, ALPHAI		0.207	
10	Circumferential Stress Equivalent Pressure, Peq	(psi)	15.806	
11	'X' Parameter, X= (Peq/8E) (d/t)^2		0.087	
12	Delta C (From Figure -)	-	0.072	
13	Modified Capacity Reduction Factor, ALPHA,1, mod		0.326	
14	Reduced Elastic Instability Stress, Se	(ksi)	15.182	2.001
	*** PLASTICITY REDUCTION FACTOR CALCULATION			
15	Yield Stress Ratio, DELTA=Se/Sy		0.400	
16	Plasticity Reduction Factor, NUi		1.000	
17	Inelastic Instability Stress, Si = NUi x Se	(ksi)	15.182	2.001
	*** ALLOWABLE COMPRESSIVE STRESS CALCULATION			
18	Allowable Compressive Stress, Sall = SI/FS	(ksi)	7.591	1.000
19	Compressive Stress Margin, M-(Sall/Sm -1) x 100%	(%)	0.0	

CALCULATION OF BUCKLING MARGIN - REFUELING CASE, NO SAND - GE OYCRFST01 - UNIFORM THICKNESS t=0.776 Inch

ITEM	PARAMETER	UNITS	VALUE	LOAD FACTOR
	*** DRYWELL GEOMETRY AND MATERIALS			
1	Sphere Radius, R	(in.)	420	
2	Sphere Thickness, t	(in.)	0.776	
3	Material Yield Strength, Sy	(ksi)	38	
4	Material Modolus of Elasticity, E	(ksi)	29600	
5	Factor of Safety, FS		2	
	*** BUCKLING ANALYSIS RESULTS			
6	Theoretical Elastic Instability Stress, Ste	(ksi)	49.357	6.857
	***STRESS ANALYSIS RESULTS			
7	Applied Meridional Compressive Stress, Sm	(ksi)	7.198	5.588
8	Applied Circumferential Tensile Stress, Sc	(ksi)	4.248	3.300
	*** CAPACITY REDUCTION FACTOR CALCULATION			
9	Capacity Reduction Factor, ALPHAI		0.207	
10	Circumferential Stress Equivalent Pressure, Peq	(psi)	15.697	
11	'X' Parameter, X= (Peq/8E) (d/t)^2		0.078	
12	Delta C (From Figure -)	-	0.066	
13	Modified Capacity Reduction Factor, ALPHA,1, mod		0.316	
14	Reduced Elastic Instability Stress, Se	(ksi)	15.583	2.165
	*** PLASTICITY REDUCTION FACTOR CALCULATION			
15	Yield Stress Ratio, DELTA=Se/Sy		0.410	
16	Plasticity Reduction Factor, NUi		1.000	
17	Inelastic Instability Stress, Si = NUi x Se	(ksi)	15.183	2.165
	*** ALLOWABLE COMPRESSIVE STRESS CALCULATION			
18	Allowable Compressive Stress, Sall = SI/FS	(ksi)	7.592	1.082
19	Compressive Stress Margin, M-(Sall/Sm -1) x 100%	(%)	8.2	

GPU Nuclear

Subject		Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed		C-1302-187-5320-024	1	52 of 114
Originator	**Date**	**Reviewed by**		**Date**
Mark Yekta	01/12/93	S. C. Tumminelli		

CALCULATION OF BUCKLING MARGIN - REFUELING CASE, NO SAND -
GPUN EVALUATION FOR UNIFORM THICKNESS t=0.800 Inch USING THICKNESS RATIO

ITEM	PARAMETER	UNITS	VALUE	LOAD FACTOR
	*** DRYWELL GEOMETRY AND MATERIALS			
1	Sphere Radius, R	(in.)	420	
2	Sphere Thickness, t	(in.)	0.800	
3	Material Yield Strength, Sy	(ksi)	38	
4	Material Modolus of Elasticity, E	(ksi)	29600	
5	Factor of Safety, FS		2	
	*** BUCKLING ANALYSIS RESULTS			
6	Theoretical Elastic Instability Stress, Ste	(ksi)	50.884	7.288
	***STRESS ANALYSIS RESULTS			
7	Applied Meridional Compressive Stress, Sm	(ksi)	6.982	5.588
8	Applied Circumferential Tensile Stress, Sc	(ksi)	4.120	3.300
	*** CAPACITY REDUCTION FACTOR CALCULATION			
9	Capacity Reduction Factor, ALPHAI		0.207	
10	Circumferential Stress Equivalent Pressure, Peq	(psi)	15.697	
11	'X' Parameter, X= (Peq/8E) (d/t)^2		0.073	
12	Delta C (From Figure -)	-	0.063	
13	Modified Capacity Reduction Factor, ALPHA,1, mod		0.311	
14	Reduced Elastic Instability Stress, Se	(ksi)	15.824	2.266
	*** PLASTICITY REDUCTION FACTOR CALCULATION			
15	Yield Stress Ratio, DELTA=Se/Sy		0.416	
16	Plasticity Reduction Factor, NUi		1.000	
17	Inelastic Instability Stress, Si = NUi x Se	(ksi)	15.824	2.266
	*** ALLOWABLE COMPRESSIVE STRESS CALCULATION			
18	Allowable Compressive Stress, Sall = SI/FS	(ksi)	7.912	1.133
19	Compressive Stress Margin, M-(Sall/Sm -1) x 100%	(%)	13.3	

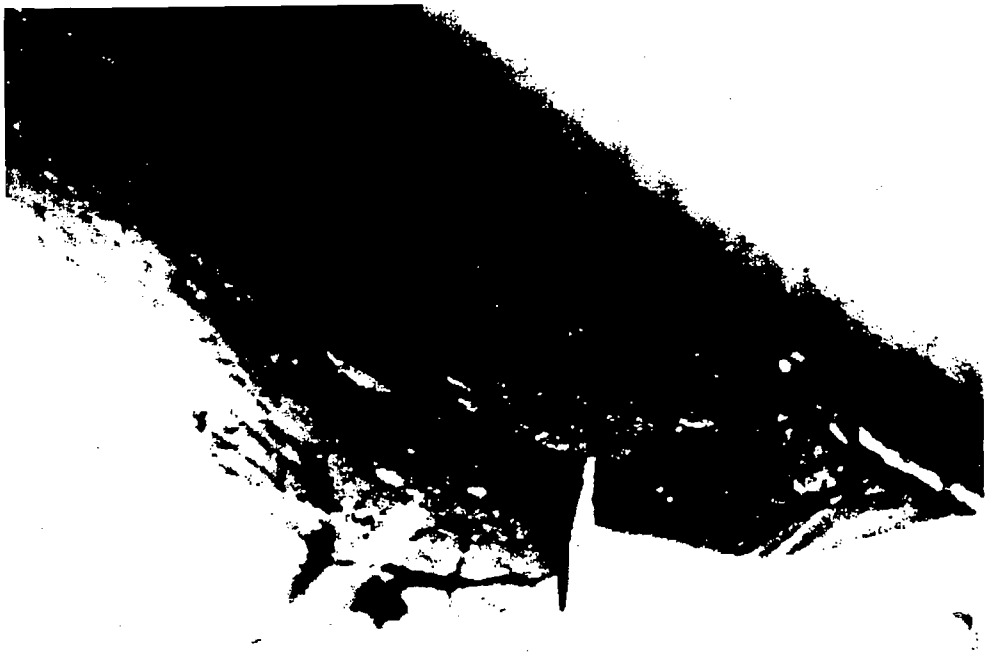
GPU Nuclear

Subject		Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed		C-1302-187-5320-024	1	53 of 114
Originator	**Date**	**Reviewed by**		**Date**
Mark Yekta	01/12/93	S. C. Tumminelli		

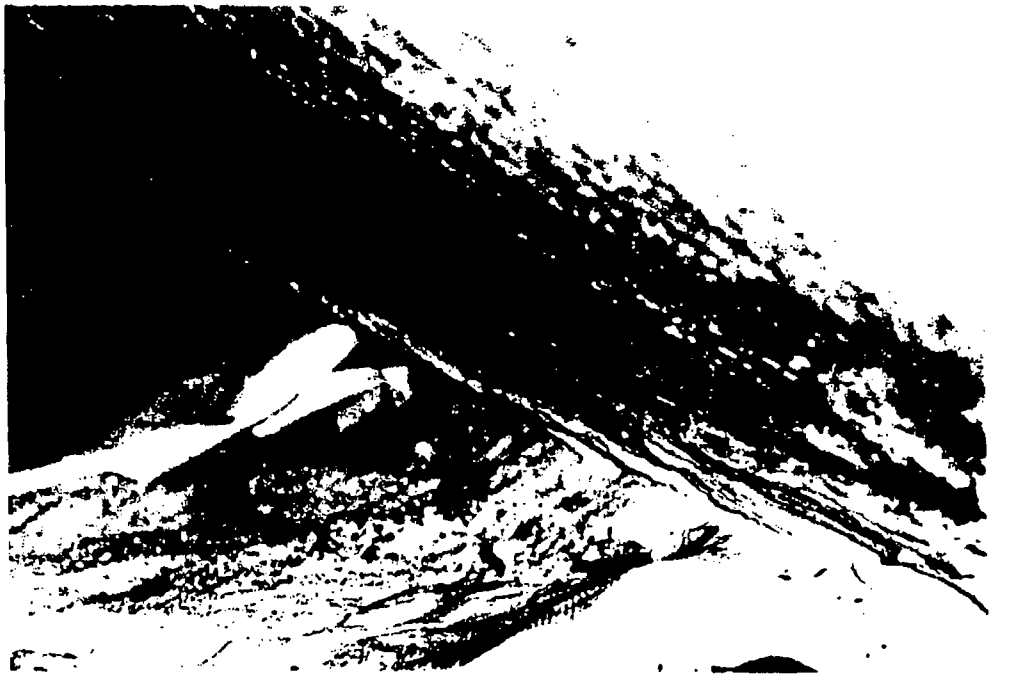
CALCULATION OF BUCKLING MARGIN - REFUELING CASE, NO SAND -
GPUN EVALUATION FOR UNIFORM THICKNESS t=0.850 Inch USING THICKNESS RATIO

ITEM	PARAMETER	UNITS	VALUE	LOAD FACTOR
	*** DRYWELL GEOMETRY AND MATERIALS			
1	Sphere Radius, R	(in.)	420	
2	Sphere Thickness, t	(in.)	0.850	
3	Material Yield Strength, Sy	(ksi)	38	
4	Material Modolus of Elasticity, E	(ksi)	29600	
5	Factor of Safety, FS		2	
	*** BUCKLING ANALYSIS RESULTS			
6	Theoretical Elastic Instability Stress, Ste	(ksi)	54.063	8.227
	***STRESS ANALYSIS RESULTS			
7	Applied Meridional Compressive Stress, Sm	(ksi)	6.571	5.588
8	Applied Circumferential Tensile Stress, Sc	(ksi)	3.878	3.300
	*** CAPACITY REDUCTION FACTOR CALCULATION			
9	Capacity Reduction Factor, ALPHAI		0.207	
10	Circumferential Stress Equivalent Pressure, Peq	(psi)	15.697	
11	'X' Parameter, X= (Peq/8E) (d/t)^2		0.065	
12	Delta C (From Figure -)	-	0.057	
13	Modified Capacity Reduction Factor, ALPHA,1, mod		0.300	
14	Reduced Elastic Instability Stress, Se	(ksi)	16.257	2.474
	*** PLASTICITY REDUCTION FACTOR CALCULATION			
15	Yield Stress Ratio, DELTA=Se/Sy		0.428	
16	Plasticity Reduction Factor, NUi		1.000	
17	Inelastic Instability Stress, Si = NUi x Se	(ksi)	16.257	2.474
	*** ALLOWABLE COMPRESSIVE STRESS CALCULATION			
18	Allowable Compressive Stress, Sall = SI/FS	(ksi)	8.128	1.237
19	Compressive Stress Margin, M-(Sall/Sm -1) x 100%	(%)	23.7	

Appendix C: Pictures Showing Condition Of The Drywell In The Sandbed Region (9 pages total)



Sand Bed Region - Typical condition found on initial entry.



Corrosion product on drywell vessel

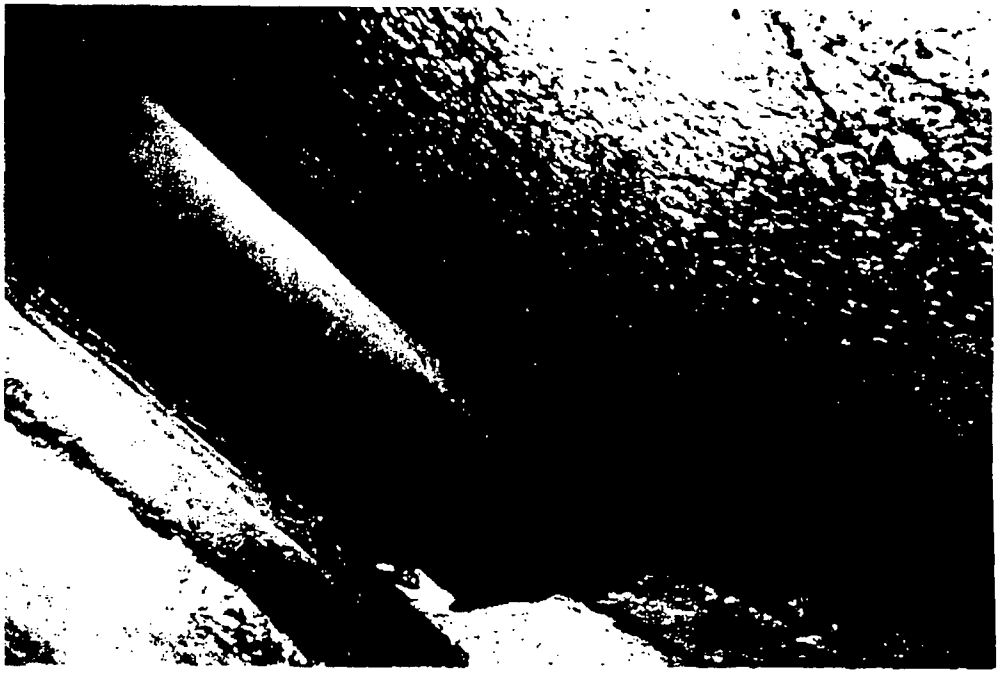
Bay #13 - D/W shell showing plug . The plug is located in the middle of the worst corroded area of the shell The plug showed no sign of corrosion.

Bay #13 - D/W shell showed less prominent "Tub Ring" than what was seen in other

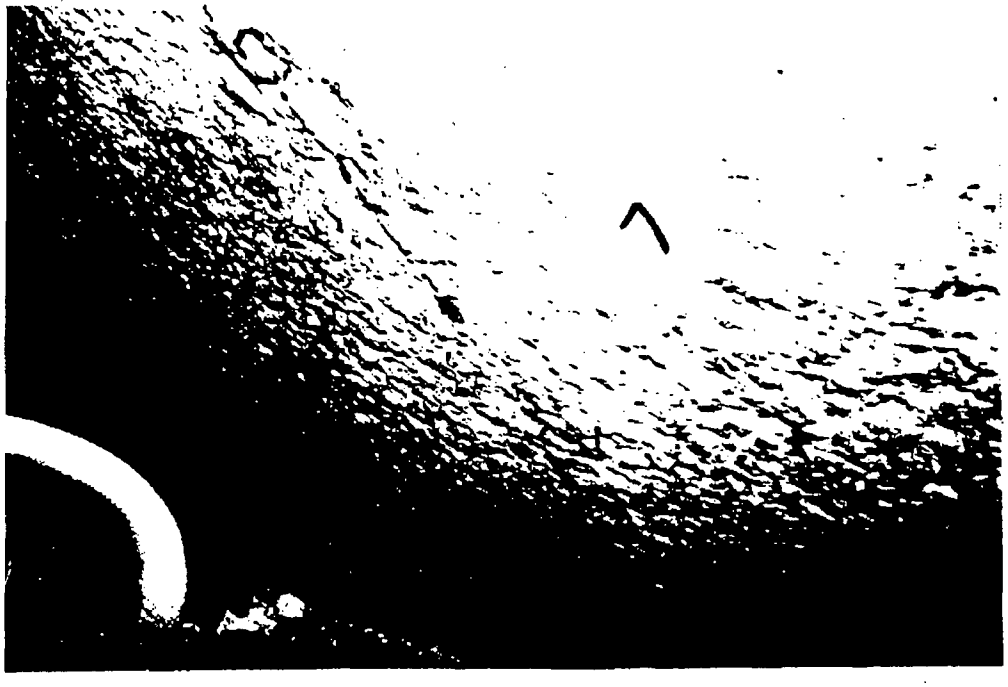
Bay #1 - Looking at the worst corroded area on shell near vent tube collar/ring. The ground spots seen here correspond to UT spot 20-21-22-3

Bay #13 - Lower Mid portion of the D/W shell showing UT spot 5,6 and 10. This close up photo shows the roughness of the corroded surface and how each UT spot has been picked up in the deep valleys thereby biasing the remaining wall readings to the conservative side

Bay #13 - Looking towards **Bay#11** - Upper right corner of D/W shell. Note ① - Grinding depth on UT spot #1 & 2, ② - A part of "Bath Tub Ring" as delineated by marking and ③ locations of UT spots 3,4,13 & 17. The photo on right (although blurred by flash reflection) shows 1/8" projection of plug.

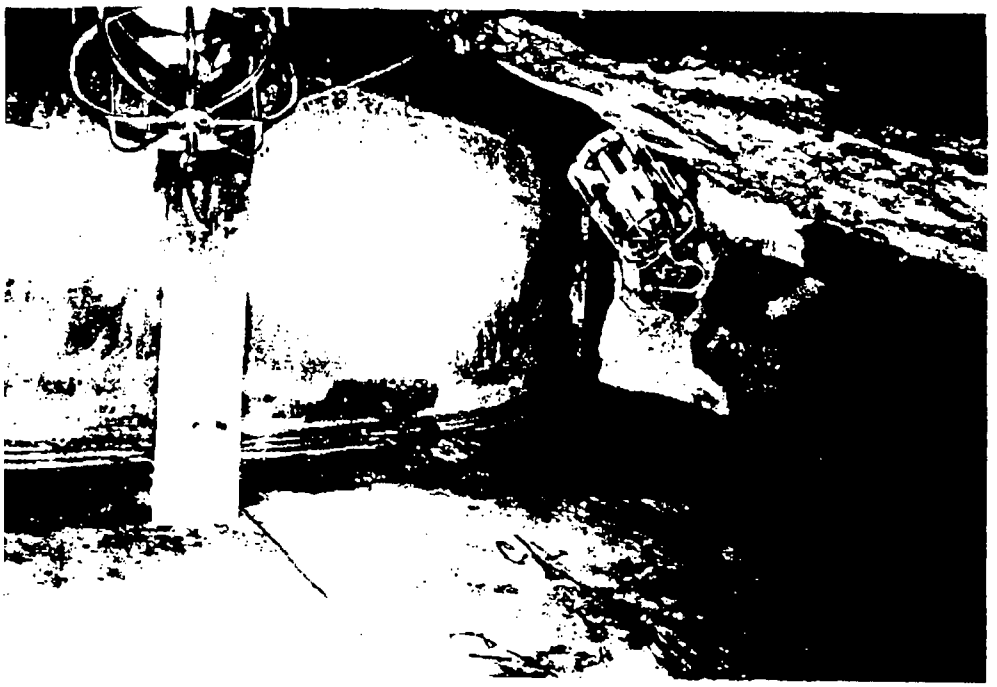


Bay #15 Looking towards **Bay#17** which has been closed with foam for coating work in Bay #17. Note the typical surface of the D/W shell and localized corroded spot

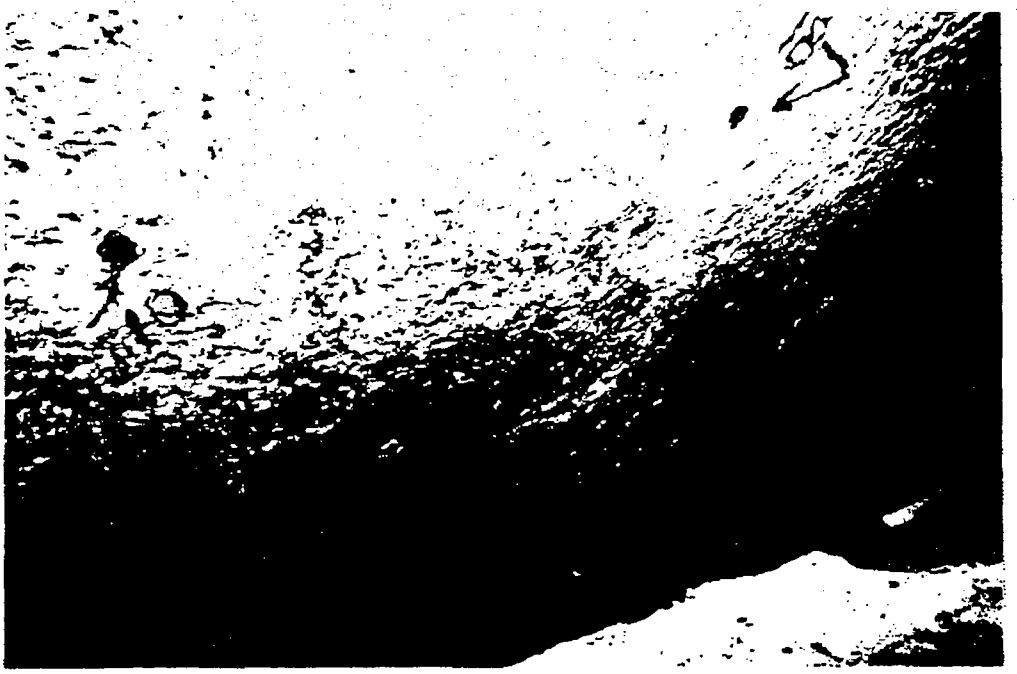


Bay #13 - Looking toward Bay #15 - Lower left corner showing UT spot #7,12 & 16. This close up has captured the peaks and valleys of the corroded shell in vivid detail. Later NDE inspection revealed depth between peaks and valleys in the 0.25" - 0.40"

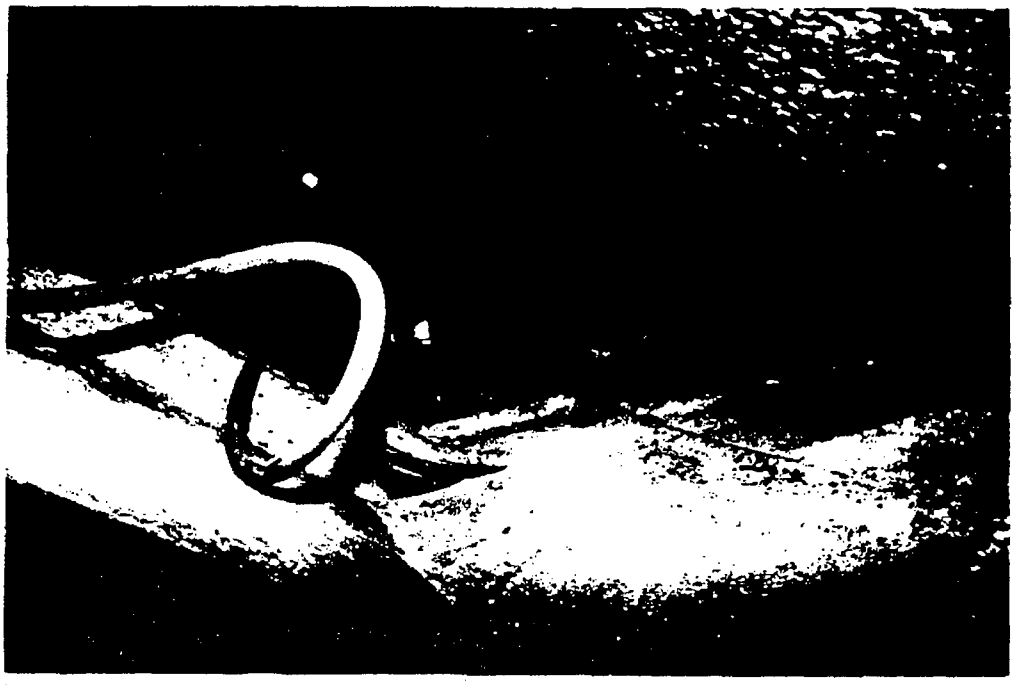
Bay #15 Looking toward **Bay #13** showing portions of D/W shell and concrete floor, after removal of loose debris / sand / rust. The concrete floor in this bay is one of the better ones. However - Note ① no drainage channel and ② cratered holes near shell corner



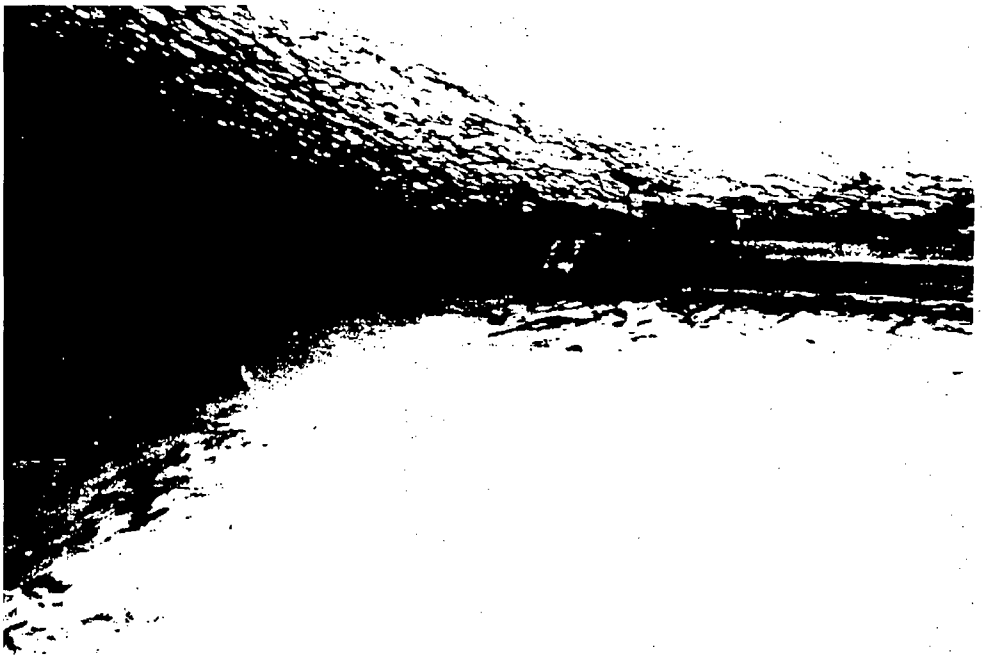
Bay #15 - Note the original lead primer on vent tube OD surface. The "Tub Ring" was less prominent on the shell in this bay except a portion in lower left corner. Also note presence of lead primer on vent collar/ring plate.



Bay #13 Looking toward **Bay #11** - Lower right corner of D/W shell showing UT spots 9, 10, 18 & 19 Note the location of these spots - all are located in the valleys of the corroded surface This photo also shows the condition of the concrete floor. It appears



Bay #13 - Looking toward **Bay #15** - This photo captures the concrete floor condition and a portion of lower shell corroded surface in very great detail. The floor in this area



Finished floor, vessel with two top coats - caulking material applied.

Drain after floor has been returbished

Appendix D: NDE Inspection Sheets for the Drywell Sandbed Region (52 pages total)

GPU Nuclear

NDE Request
Oyster Creek

QC Charge No. 351A-57307 Request No. 92-C72

1 To be filled in by Requestor

Job Order No.	Short Form No.	BA No. 328295	Date of Request

Job Description: UT THICKNESS OF D W LINER

System:

Job Location: SAND BED AREA

Applicable Code/Specification: INR FR LND

Type of NDE requested:

- ☐ Visual
- ☐ Leakage
- ☐ Video
- ☐ Liquid Penetrant
- ☐ Magnetic Particle
- ☐ Radiographic
- ☐ Eddy Current
- ☐ Alloy Separator
- ☐ Ferrite
- ☒ Ultrasonic
- ☐ Acoustic Emissions

NDE Requested by: J SLITER FOR JOHN FLYNN | Phone No.: | Date 12-5-92

Remarks

2 To be filled in by NDE Coordinator

NDE Coordinator: J SLITER | Date

Instructions

UT	PT	MT	RT	VT	ET
☒ 0°	Type	Dry	Isotope	☐ Direct	☐ Probe
☐ 45°	☐ A-1	☐ Red	☐ Ir^{192}	☐ Weld Insp	☐ Double
☐ 60°	☐ A-2	☐ Black	☐ Co^{60}	INDIRECT/VIDEO	☐ Single
☐ 70°	☐ A-3	☐ Grey	X-Ray	☐ Mirror	☐ Coil
☐ Other	☐ B-1	☐ Other	☐ 150 KV	☐ Boroscope	☐ Double
☐ Acoustic Emissions	☐ B-2	Wet	☐ 250 KV	☐ Fiberoptic	☐ Single
	☐ B-3	☐ Black		☐ Binocular	☐ Alloy Sep.
		☐ Flourescent		☐ Camera	☐ Ferrite

Remarks

Results: ☑ Accept ☐ Reject ☐ Only

MNCR #'s open/close/cond. rel.: N/A

Proc. No.

Proc. No.

Proc. No.

Job start date | Job stop date

NDE Coordinator | Date Closed 1-29-93 | Date to DCC

Yellow - Originator Final Copy Gold - Originators Initial Copy N60892 (03-87)
Pink - NDE Field Work Copy

GPU Nuclear

NDE/ISI Report Log

Page _____ of _____

Oyster Creek - QC

NDE Req. # 92 - 072

Test: ☐ PT ☐ MT ☒ VT ☐ RT ☐ UT ☐ _____

System/Location: _____

Item: _____

Report #	Test Type	Date of Test	Results: Acc	Results: Rej	Results: Recordable	Remarks:
92-072-21	UT	1-8-93				BAY 15
92-072-22	UT	1-7-93				BAY 9
92-072-23	UT	1/8/93				BAY 13
92-072-24	UT	1-11-93				BAY 13
92-072-25	UT	1-11-93				BAY 13
92-072-26	UT	1-11-93				BAY 13
92-072-27	VT	1-11-93				BAY 13 DEPTH GAUGE
92-072-28	VT	1-12-93				BAY 1 DEPTH GAUGE
92-072-29	VT	1-12-93				BAY 17 DEPTH GAUGE
92-072-30	VT	1-12-93				BAY 15 DEPTH GAUGE
92-072-31	VT	1-12-93				BAY 11 DEPTH GAUGE

Form ID 6133ADM 7230 01-2 (8/82)

GPU Nuclear

Oyster Creek - QC

NDE/ISI Report Log Page ____ of ____

NDE Req. #: 92-072

Test: ☐ PT ☐ MT ☐ VT ☐ RT ☒ UT ☐ ____

System/Location: DW LINER SANDBED

Item: ____

Report #	Test Type	Date of Test	Results: Acc	Results: Rej	Results: Recordable	Remarks:
92-072-01	UT	12-5-92				BAY 17
92-072-02	UT	12-5-92				BAY 19
92-072-03	UT	12-14-92				BAY 19
92-072-04	UT	12-14-92				BAY 17
92-072-05	UT	12-14-92				BAY 19
92-072-06	UT	12-14-92				BAY 17
92-072-07	UT	12-11-92				BAY 19
92-072-08	UT	12-11-92				BAY 17
92-072-09	UT	12-22-92				BAY 11
92-072-10	UT	12-22-92				BAY 11
92-072-11	VT	12-16-92				OVERLAY PLATE
92-072-12	UT	1-2-93				BAY 1
92-072-13	UT	1-2-93				BAY 1
92-072-14	UT	1-2-93				BAY 3
92-072-15	UT	1-2-93				BAY 3
92-072-16	UT	1-2-93				BAY 5
92-072-17	UT	1-2-93				BAY 5
92-072-18	UT	1-4-93				BAY 1
92-072-19	UT	1-5-93				BAY 1
92-072-20	UT	1-8-93				BAY 7

Form ID 6133ADM 7230 01-2 (8/87)

A0001537

Program	Xducer	Screen	Digital
1	5 mhz 3/4" Single H31900 (SP)	2"	2"
2	2.25 mhz 3/4" Single F28932	2"	2"
3	2 mhz MSEB MC8524	2"	2"
4	5 mhz bubbler water delay	2" delayed	2" delayed
5	5 mhz bubbler water delay	2" sync. screen	NONE
6	5 mhz bubbler water delay	2" sync. screen	2"
7	5 mhz 3/4" single H31900(SP)	1"	1"
8	2 mhz MSEB MO8524	1"	1"
9	5 mhz 1/4" delay G00504 single	2"	NONE
10	5 mhz 1/4" dual 014252	1"	1"
11	5 mhz 1/4" dual 014252	2"	2"

Jamie for your info. [illegible]

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	68 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear — Ultrasonic Thickness Data Sheet

☑ OC ☐ TMI-1 ☐ TMI-2 | Class: N/A | Item: N/A | NDE Request: 92-072 | Data Sheet No.: 92-072-12

Task Description: UT Thickness | Task No.: 01A | Date: 1/2/93

Comp. Desc.: Drywell Liner | System: 187 | Code/Spec.: ENG INFOR.

Procedure/Rev.: 6100-QAP-7209.07 Rev. 0 | Drawing No./Rev.: 3E-187-29-001 Rev. 0

Test Surface: O.D. | Thickness: 1 1/8" | Material: C/S

Examiner	Sign: [signature]	Print: J. VanDer Linde	ID No.: 154-48-0318	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-81-1862	Level: I

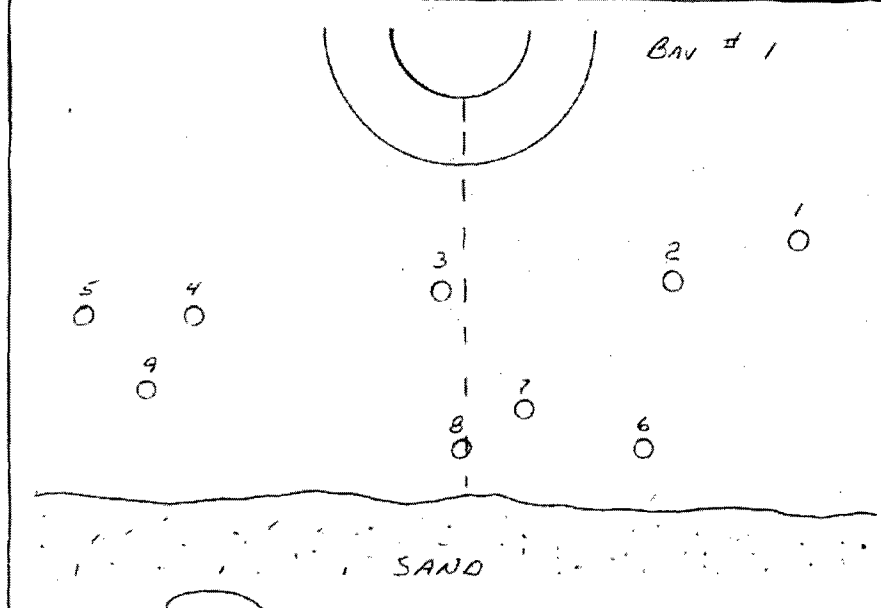
Thermometer S/N 88-081 Part Temperature 22 F D-Meter S/N 92-035
Cal. Blk. S/N 214 Cal. In: N/A AM 11:51 PM
Cal. Blk. Temp. 22 F Cal. Out: N/A AM 22:15 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☐ CRT ☒ D-Meter
Other N/A

Position #/Reading In Inches



Drawing

	AREA		MEASUREMENT
1	0-16"	R30"	.720
2	0-22"	R17"	.716
3	0-23"	L3"	.705
4	0-24"	L33"	.700
5	0-24"	L45"	.710
6	0-48"	R16"	.700
7	0-39"	R5"	.700
8	0-48"	0"	.655
9	0-36"	L38"	.605

Reviewed by: [signature] | Level: III | Date: 1-5-93 | Page 1 of 91

GPU Nuclear

Subject	Calc No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	69 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli	**Rev. No.** 1
Date 01/12/93		**Date**

GPU Nuclear — Ultrasonic Thickness Data Sheet

☑ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-13
Task Description: UT Thickness		Task No.: N/A	Date: 1/2/93
Comp. Desc.: Drywell Liner	System: 187	Code/Spec.: ENG INFOR
Procedure/Rev.: 6100-QAP-7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner Sign:	Print: J. Van der Linde	ID No.: 154-48-0318	Level: II
Examiner Sign: Mark F. Bagnell	Print: Mark F. Bagnell	ID No.: 553-BI-1802	Level: I

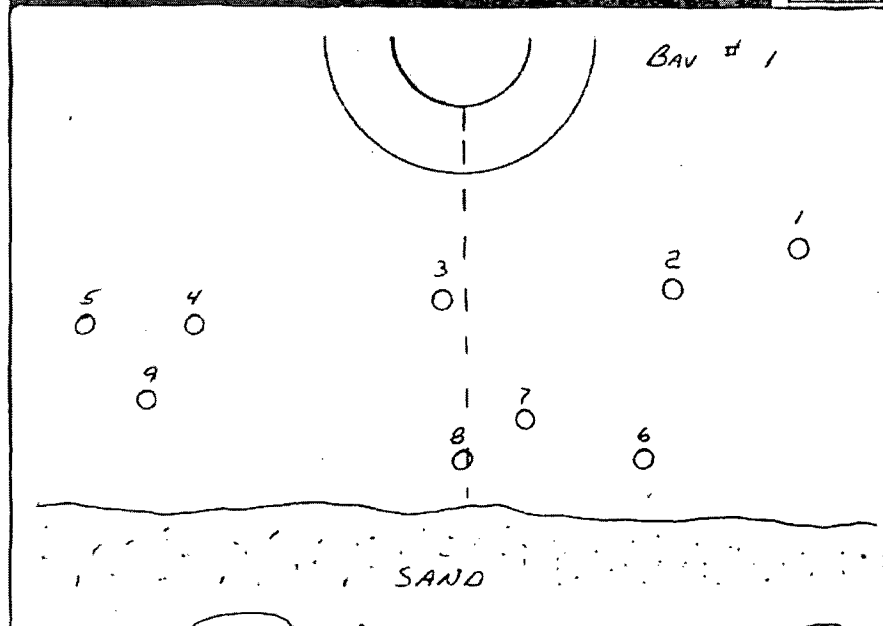
Thermometer S/N 88-081 Part Temperature 22 F D-Meter S/N 137-113
Cal. Blk. S/N 214 Cal. In: N/A AM 21:51 PM
Cal. Blk. Temp. 22 F Cal. Out: N/A AM 22:15 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☒ CRT ☐ D-Meter
Other N/A

Position #/Reading In Inches



Drawing

	AREA		MEASUREMENT
1	0-16"	R30"	700*
2	0-22"	R17"	710*
3	0-23"	L3"	690*
4	0-24"	L33"	750
5	0-24"	L45"	680*
6	0-48"	R16"	700*
7	0-39"	R5"	690*
8	0-48"	0"	800
9	0-36"	L38"	800

J. Smith

Reviewed by: [illegible] Level: III Date: 1-3-93 Page 21 of 81

2 Points under

GPU Nuclear

Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No. 92-072-19
Task Description: UT THICKNESS			Task No.: N/A	Date: 1-4-93
Comp. Desc.: DRYWELL LINER Bay 1	System: 187		Code/Spec.: ENG. INFO.	
Procedure/Rev.: 6100-QAP-7209.07 REV. 0		Drawing No./Rev.: 3E-187-29-001		
Test Surface: O.D.		Thickness: 1 1/8"	Material: C.S.	
Examiner	Sign: [signature]	Print: Joel VanderLinde	ID No.: 134-48-0319	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-81-1862	Level: I

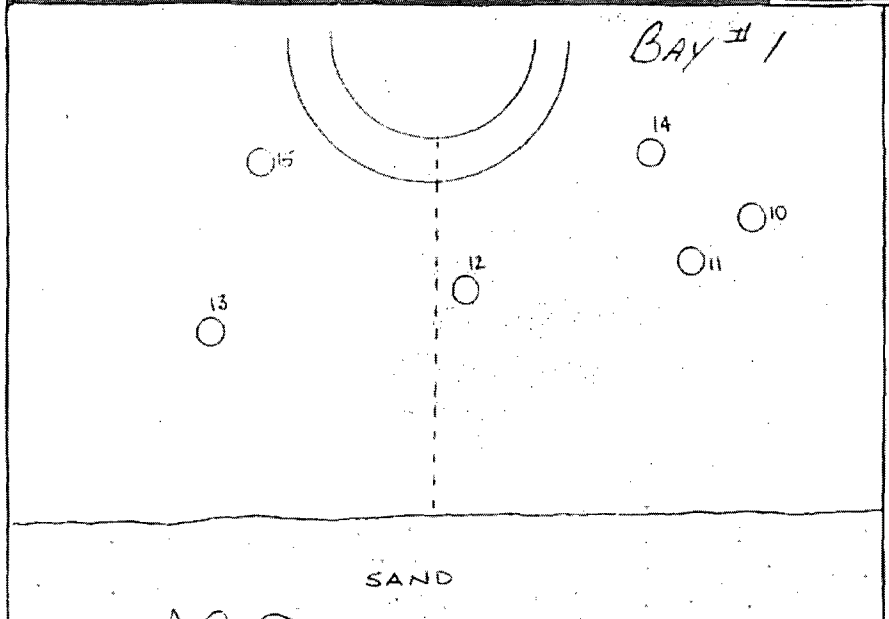
Thermometer S/N 92-068 Part Temperature 76° F D-Meter S/N 92-056
Cal. Blk. S/N INV 219 Cal. In: N/A AM 23:11 PM
Cal. Blk. Temp. 76° F Cal. Out: N/A AM 23:24 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☐ CRT ☒ D-Meter
Other N/A

Position #/Reading In Inches



Drawing

	AREA	MEASUREMENT
10	D 16" R 23"	833"
11	D 23" R 12"	714"
12	D 24" L 5"	724"
13	D 24" L 40"	792"
14	D 2" R 35"	1.147"
15	D 6" L 51"	1.156"

NOTE ADDITIONAL READINGS TAKEN FOR CONFORMATION OF PREVIOUS INSPECTION

Reviewed by: [signature] Level: II Date: 1-5-93 Page 1 of 1

NS455 (05/90)

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed		Calc No. C-1302-187-5320-024	Sheet No. 70 of 114
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tummineli	Rev. No. 1
			Date

GPU Nuclear

Subject	Calc No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	71 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli	
Date 01/12/93	**Rev. No.** 1	**Date**

GPU Nuclear

☒ OC ☐ TMI ☐ OTHER _____

Sketch Form (with grid)

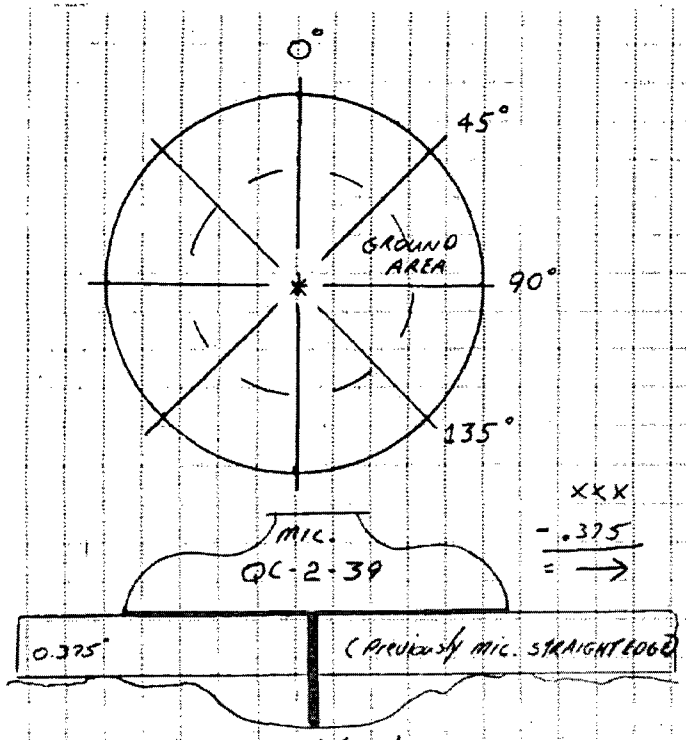
Component: DRYWELL liner SANDBED AREA

Data Sheet No.: 92-072-28

Location: BAY # 1

Drawing No.: N/A Rev.: N/A

Drawing



xxx
- .375
= →

Technique utilized for The Pit depth MEASUREMENTS

AZIMUTH

AREA	0°	45°	90°	135°
1	.272	.204	.206	.185
2	.143	.133	.143	.154
3	.397	.316	*	.329
5	.330	.290	.304	.330
7	.208	.281	.246	.330
11	.200	.211	.225	.211
12	.279	.316	.261	.328
21	.222	.202	.238	.183

* VALLEY FROM AREA #12 INTERFERERD WITH ~~TAKE~~ TAKING MEANINGFUL MEASUREMENT PRA 1/12/93

Prepared by: [signature]

Title: VT LV II

Date: 1-12-93

Reviewed by: [signature]

Level: II

Date: 1-13-93

Page 1 of 1

NDE Request No.: 92-072

ORM 6130-QAP-7200.06 (12-83)

one point under

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-F1
Task Description: UT THICKNESS			Task No.: N/A	Date: 1-5-93
Comp. Desc.: DRYWELL LINER Bay 1	System: 187		Code/Spec.: ENG INFO.	
Procedure/Rev.: 6100-QAP-7209.01 REV. 0		Drawing No./Rev.: 3E-187-28-001 REV. 0		
Test Surface: O.D.		Thickness: 1 1/8"	Material: C.S.	
Examiner	Sign: [signature]	Print: Jan Van der Grijp	ID No.: 154-45-0319	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bergnell	ID No.: 553-81-1822	Level: I

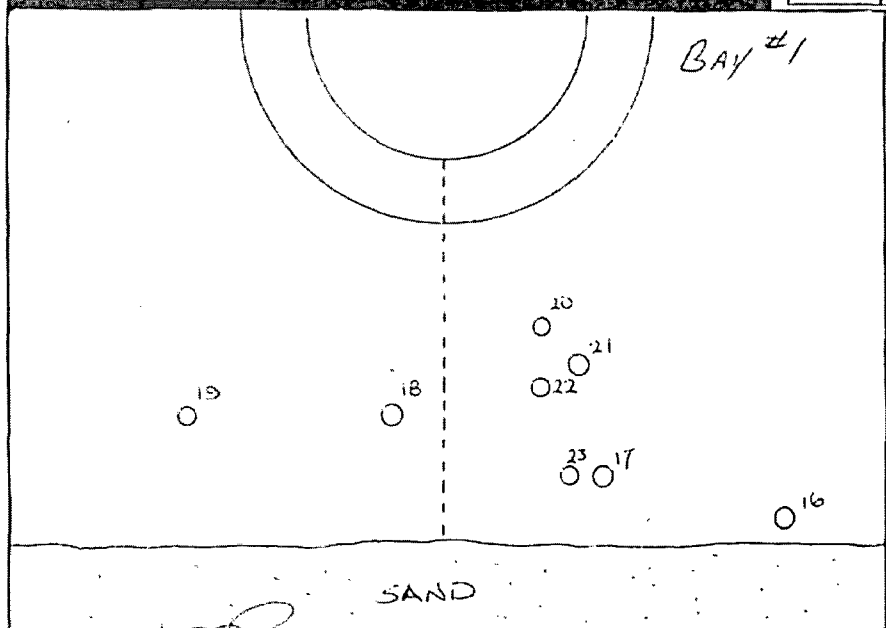
Thermometer S/N 88-081 Part Temperature 72°F D-Meter S/N 90-056
Cal. Blk. S/N INV 214 Cal. In: N/A AM 22:42 PM
Cal. Blk. Temp. 72° F Cal. Out: N/A AM 22:55 PM

Calibration Readings (Inches)

Cal. Blk.	5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☐ CRT ☒ D-Meter
Other N/A

Position #/Reading In Inches



Drawing

	AREA		MEASUREMENT
16	D 50"	R 40"	796"
17	D 48"	R 16"	860"
18	D 38"	L 2"	917"
19	D 38"	L 24"	890"
20	D 18"	R 13"	965"
21	D 24"	R 15"	726" *
22	D 32"	R 13"	852"
23	D 48"	R 15"	850"

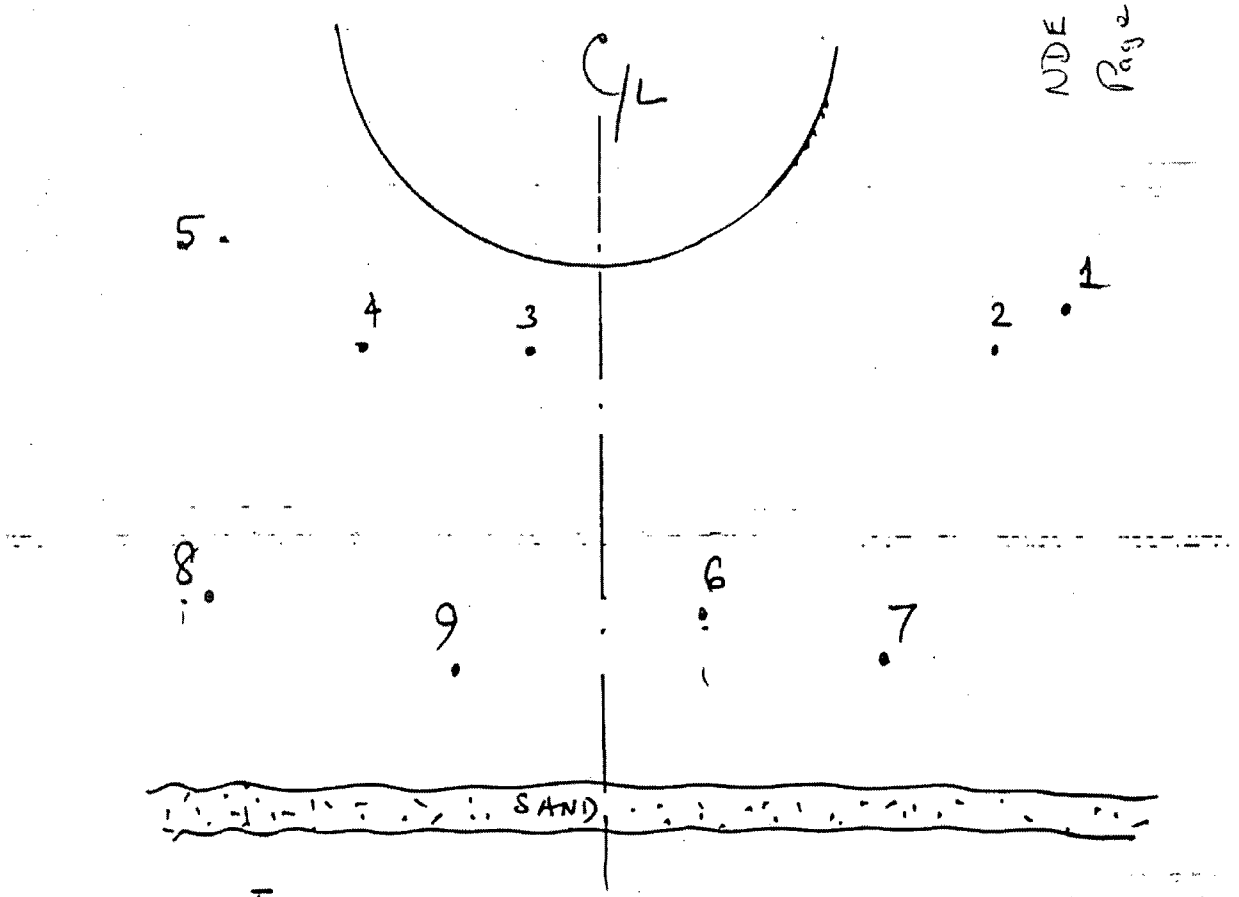
Reviewed by: [signature] Level: II Date: 1-6-93 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed		Calc No.: C-1302-187-5320-024	Rev. No.: 1
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Date
			Sheet No.: 72 of 114

NDE REQ. 92.072
Page 3 of 9



INSPECTION SPOTS FOR UT
BAY #1

NOTE:

1. GRIND FLAT FOR UT WITH MINIMUM REMOVAL OF SHELL AT THE VALLEY.

All Good

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☑ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-14
Task Description: UT Thickness			Task No.: N/A	Date: 1/2/93
Comp. Desc.: Drywell Liner	System: 187		Code/Spec.: EVUL. INFOR	
Procedure/Rev.: 6100-GNP-7209.07 Rev. 0		Drawing No./Rev.: 3C-187-29 001 Rev. 6		
Test Surface: O.D.		Thickness: 1 1/8"	Material: C/S	
Examiner	Sign: [signature]	Print: J. Van der Linde	ID No.: 154-48-0318	Level: II
Examiner	Sign: Mark F. Bagnell	Print: Mark F. Bagnell	ID No.: 553-61-1602	Level: I

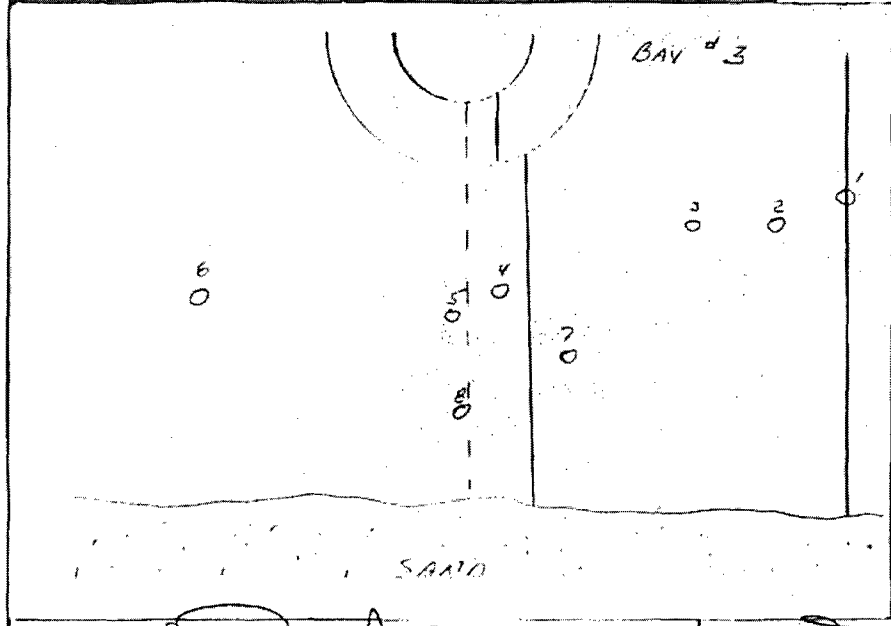
Thermometer S/N 88-081 Part Temperature 72 F D-Meter S/N 92-035
Cal. Blk. S/N 214 Cal. In: N/A AM 2118 PM
Cal. Blk. Temp. 72 F Cal. Out: N/A AM 2145 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☐ CRT ☒ D-Meter Other N/A

Position # Reading in Inches



Drawing

	AREA	MEASUREMENT
1	0-5" R-63	.795"
2	0-9" R-50	1.00"
3	0-9" R-33	.857"
4	0-13" L-5	.898"
5	0-15" L-8	.823"
6	0-15" L-56	.966"
7	0-17" R-	.626"
8	0-24" L-	.780"

Reviewed by: [signature] Level: III Date: 1-3-93 Page 41 of 91

HS455 (05/90)

GPU Nuclear			
Subject O.C. Drywell Ext. UT Evaluation in Sandbed		**Calc No.** C-1302-187-5320-024	**Rev. No.** 1	**Sheet No.** 74 of 114
Originator Mark Yekta	**Date** 01/12/93	**Reviewed by** S. C. Tumminelli		**Date**

GPU Nuclear			
Subject: O.C. Drywell Ext. UT Evaluation in Sandbed	Calc No. C-1302-187-5320-024	Rev. No. 1	Sheet No. 75 of 114
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Date

All good

Ultrasonic Thickness Data Sheet

GPU Nuclear

☑ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No. 92-072-15
Task Description: UT Thickness			Task No.: N/A	Date: 1/2/93
Comp. Desc.: Drywell Liner	System: 187		Code/Spec.: ENG. ENFOR	
Procedure/Rev.: 6100-QAP-7209.07 Rev. 0			Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.			Thickness: 1 1/8"	Material: C/S
Examiner	Sign:	Print: J. Van der Linde	ID No.: 154-48-0318	Level: II
Examiner	Sign:	Print: Mark F. Bagnell	ID No.: 553-81-1802	Level: II

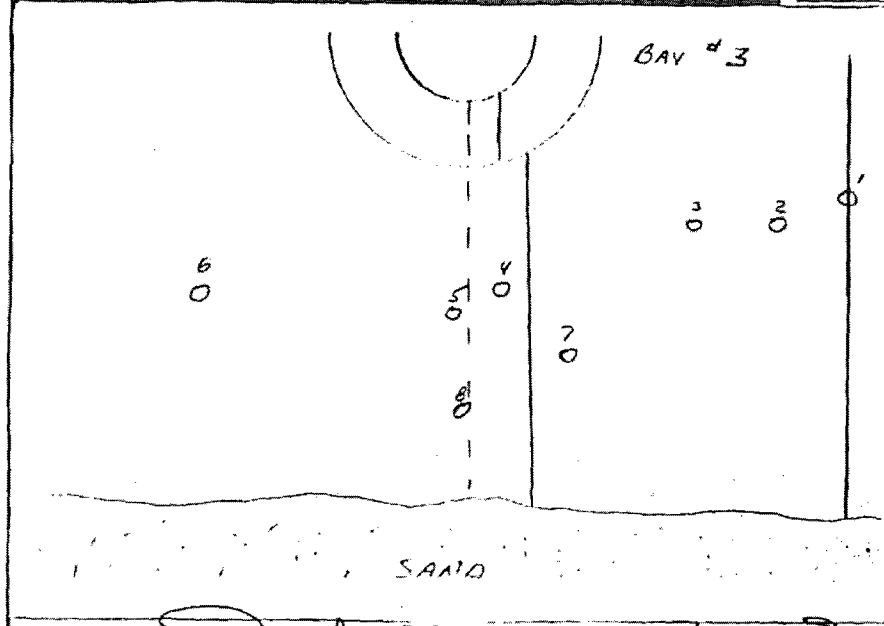
Thermometer S/N 88-081 Part Temperature 22 F D-Meter S/N 137-113
Cal. Blk. S/N 214 Cal. In: N/A AM 21:18 PM
Cal. Blk. Temp. 72 F Cal. Out: N/A AM 21:45 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	N/A

Techniques: ☒ CRT ☐ D Meter
Other N/A

Position # Reading In Inches



Drawing

	AREA	MEASUREMENT
1	0-5" R-63	.800"
2	0-9" R-50	1.00"
3	0-9" R-33	.800"
4	0-13" L-5	.900"
5	0-15" L-8	.840"
6	0-15" L-56	1.00"
7	0-17" R-	.840"
8	0-24" L-	.790"

Reviewed by: [illegible] Level: III Date: 1-3-93 Page 61 of 91

1-20-93

115455 (05 90)

All good

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☑ OC ☐ TMI-1 ☐ TMI-2 | Class: 01A | Item: 01A | NDE Request: 92-072 | Data Sheet No. 92-072-15

Task Description: UT Thickness | Task No.: 01A | Date: 1/2/93

Comp. Desc.: Drywell Liner | System: 187 | Code/Spec.: ENG. ENFOR

Procedure/Rev.: 6100-ONP-7209.07 Rev. 0 | Drawing No./Rev.: 3E-187-29-001 Rev. 0

Test Surface: O.D. | Thickness: 1 1/8" | Material: C/S

Examiner	Sign: [signature]	Print: J. Van der Linde	ID No.: 154-48-0319	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-61-1802	Level: II

Thermometer S/N 88-081 Part Temperature 22 F D-Meter S/N 157-113

Cal. Blk. S/N 214 Cal. In: N/A AM 21:18 PM

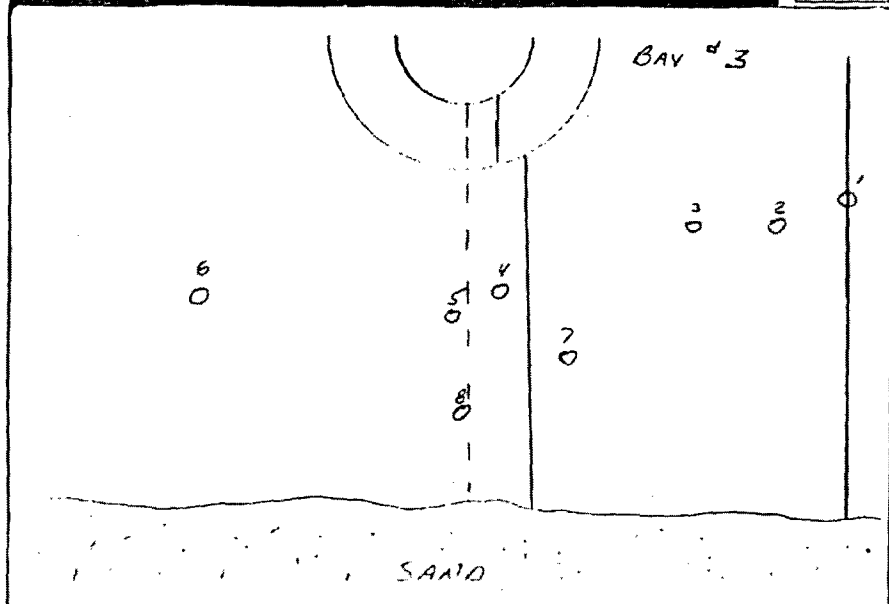
Cal. Blk. Temp. 22 F Cal. Out: N/A AM 21:45 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☒ CRT ☐ D Meter Other N/A

Position # Reading In Inches



Drawing

	AREA	Measurement
1	0-5" R-63	.800"
2	0-9" R-50	1.00"
3	0-9" R-33	.800"
4	0-13" L-5	.900"
5	0-15" L-8	.840"
6	0-15" L-56	1.00"
7	0-17" R-	.840"
8	0-24" L-	.790"

Reviewed by: [signature] | Level: III | Date: 1-3-93 | Page 81 of 91

1-20-93

(15455 (05/90)

GPU Nuclear			
Subject: O.C. Drywell Ext. UT Evaluation in Sandbed			
Originator: Mark Yekta	Date: 01/12/93	Calc No.: C-1302-187-5320-024	Rev. No.: 1
		Reviewed by: S. C. Tumminelli	Date
			Sheet No.: 77 of 114

all good

GPU Nuclear — Ultrasonic Thickness Data Sheet

☑ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-14
Task Description: UT Thickness		Task No.: N/A	Date: 1/2/93
Comp. Desc.: Drywell Liner	System: 187	Code/Spec.: ENG. INFO. R	
Procedure/Rev.: 6100-GAP 7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29.001 Rev. 0		
Test Surface: O.D	Thickness: 1 1/8"	Material: C/S	
Examiner Sign:	Print: J. VAN der Linde	ID No.: 154-43-0318	Level: II
Examiner Sign: Mark F. Bagnell	Print: Mark F. Bagnell	ID No.: 553-81-1802	Level: I

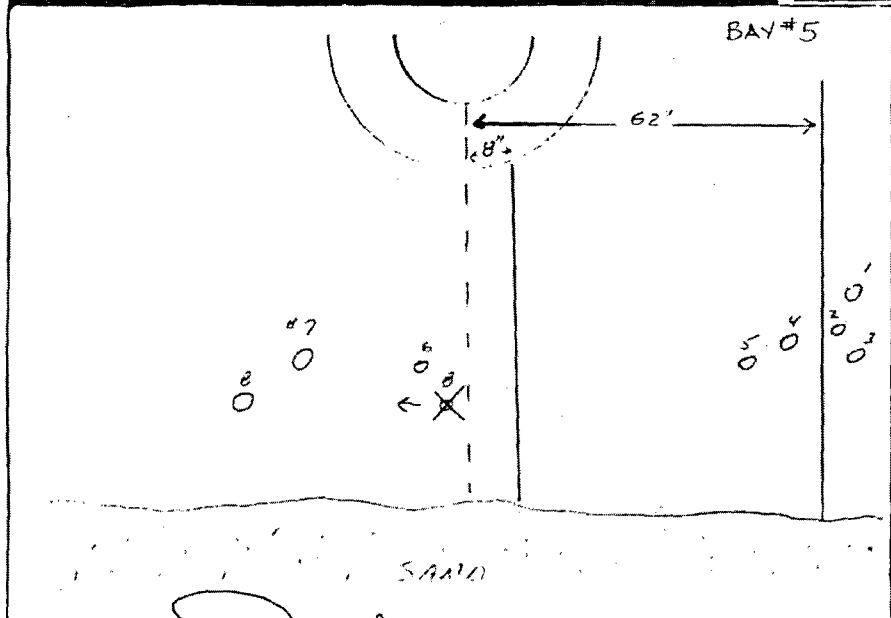
Thermometer S/N 88-081 Part Temperature 72 F D-Meter S/N 92-035
Cal. Blk. S/N 214 Cal. In: N/A AM 22:23 PM
Cal. Blk. Temp. 72 F Cal. Out: N/A AM 22:36 PM

Calibration Readings (Inches)

Cal. Blk.	.5"	.75"	1.0	1.25"	1.5"	N/A
D-Meter	.5"	.75"	1.0	1.25"	1.5"	

Techniques: ☐ CRT ☒ D-Meter
Other N/A

Position #, Reading in Inches



Drawing

	AREA	MEASUREMENT
1	0-40" R-23"	.970"
2	0-42" R-3"	1.040"
3	0-44" R-10"	1.020"
4	0-44" R-7"	.970"
5	0-46" R-11"	.890"
6	0-44" L-4"	1.000"
7	0-48" L-24"	.990"
8	0-46" L-28"	1.010"

* FROM weld

1-4-93

Reviewed by: [signature] Level: III Date: 1-3-93 Page 71 of 91

N5455 (05.90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	78 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		**Date**
Date 01/12/93			

all good

GPU Nuclear — Ultrasonic Thickness Data Sheet

☑ OC ☐ TMI-1 ☐ TMI-2 | Class: N/A | Item: N/A | NDE Request: 92-072 | Data Sheet No.: 92-072-11

Task Description: UT Thickness | Task No.: N/A | Date: 1/2/93

Comp. Desc.: Drywell Liner | System: 187 | Code/Spec.: ENG. INFO.

Procedure/Rev.: 6100-QAP-7209.07 Rev. 0 | Drawing No./Rev.: 3E-187-29.001 Rev. 0

Test Surface: O.D. | Thickness: 1 1/8" | Material: C/S

Examiner	Sign: [signature]	Print: J. Van der Linde	ID No.: 154-48-0318	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-81-1862	Level: I

Thermometer S/N 88-081 Part Temperature 72 F D-Meter S/N 137-113

Cal. Blk. S/N 214 Cal. In: N/A AM 22:23 PM

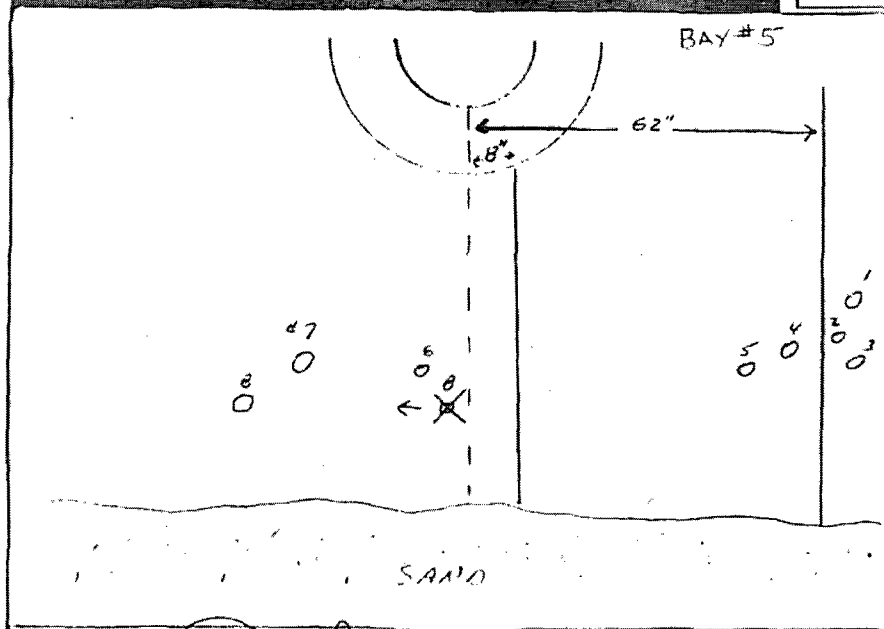
Cal. Blk. Temp. 72 F Cal. Out: N/A AM 22:38 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	1.25	1.5	N/A
D-Meter	.5	.75	1.0	1.25	1.5	

Techniques: ☒ CRT ☐ D-Meter Other N/A

Position # Reading In Inches

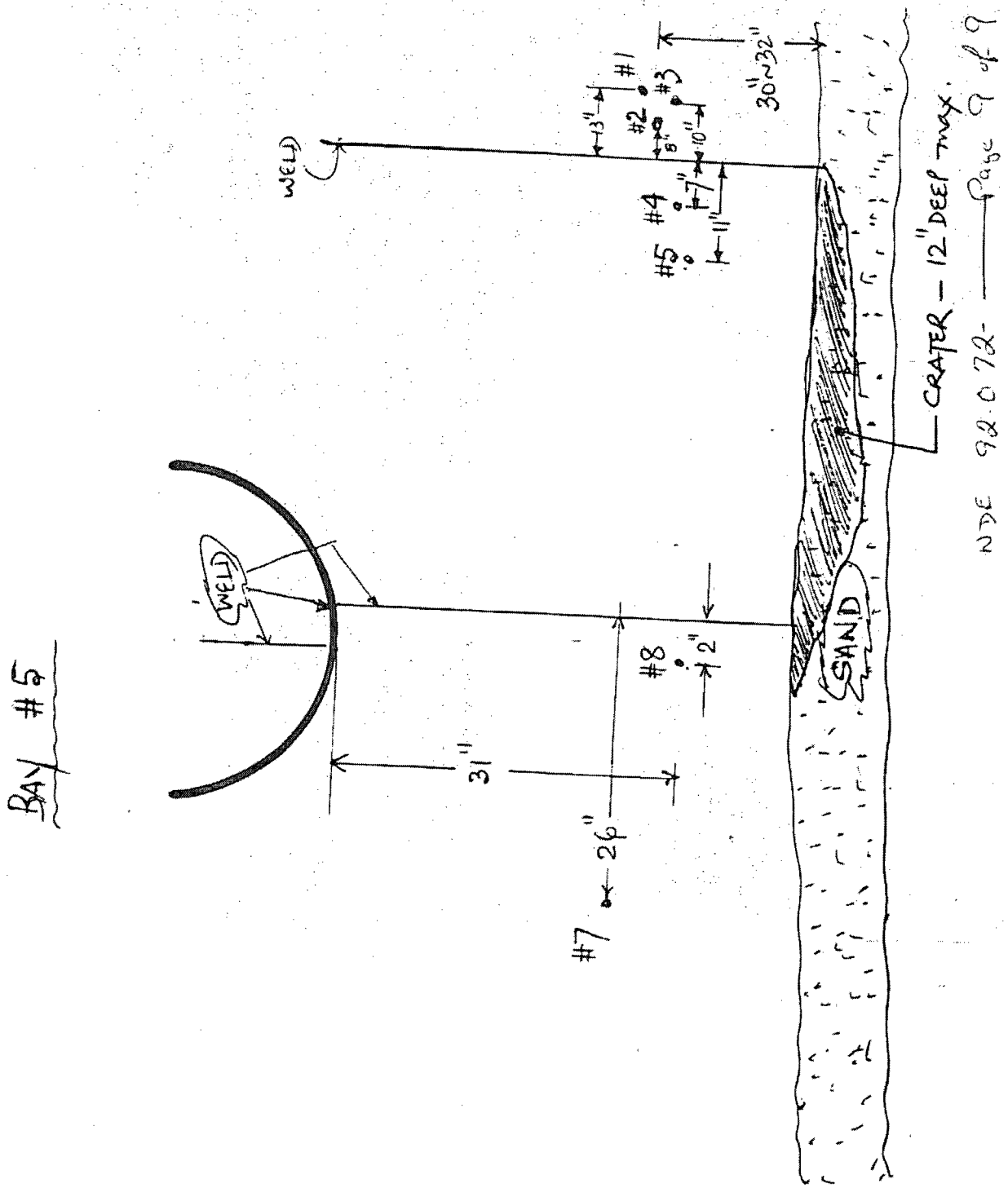


Drawing

	AREA	MEASUREMENT
1	0-40" R-13"	.910"
2	0-42" R-8"	1.030"
3	0-44" R-10"	1.040"
4	0-44" R-7"	.960"
5	0-46" R-11"	.890"
6	0-44" L-4"	1.060"
7	0-48" L-24"	1.000"
8	0-46" L-28"	1.020"

* FROM weld

Reviewed by: [signature] | Level: III | Date: 1-3-93 | Page 81 of 81


BAY #5
WELD
WELD
#1
#2
#3
#4
#5
#7
#8
13"
8"
10"
7"
11"
2"
26"
31"
30~32"
SAND
CRATER – 12" DEEP MAX.
NDE 92.0 72-
Page 9 of 9

GPU Nuclear

Subject	Originator	Date
O.C. Drywell Ext. UT Evaluation in Sandbed	Mark Yekta	01/12/93

Calc No.	Reviewed by	Rev. No.	Date
C-1302-187-5320-024	S. C. Tumminelli	1	

Sheet No.
80 of 114

GPU Nuclear

OC ITMI

Calibration Sheet

Cal Sheet# 14R-103

System	Component	Procedure	Rev
187	Drywell Liner	6100-QAP-7209.07	0

	Signature	Print	Initial	ID#	Level
Examiner:	[signature]	J Van der Linde	[initials]	154-43-0029	II
Examiner:	Mark [signature]	Mark F. Bragnell	MB	553-E1-ITC2	I

Instrument Settings
ID# 137-113
Model/Manul SONIC 137 STAVELY

Gain
Coarse 65
Fine n/a
Uncal n/a

Sweep Circuit
Coarse 2" (Range)
Fine vel. 0.231
Delay 0.995
Screen Depth 2"

Operation
(T&R) Normal
Frequency: 2.25 MHZ
Reject: [X] Off [ ] On ___ %
Filter: [ ] Off [X] On 1 %
Damping: [ ] Off [X] On 100 %

Rep Rate: 1000 Hz

Cal Standard
ID# 214
Size n/a Sch. n/a
Thickness .5 to 1.5
S/S CS
Temp 72 °F

System Check
[ ] Exit Point
[ ] Angle +/- 2 N/A

Date 1-2-93

Search Unit
ID# M08524
Type MSEB
Freq 2 MHZ
Size ½"
Angle 0 Mode Long.

Cal Direction
[ ] Axial [ ] Both
[ ] Circ. [X] Normal

Time 1900

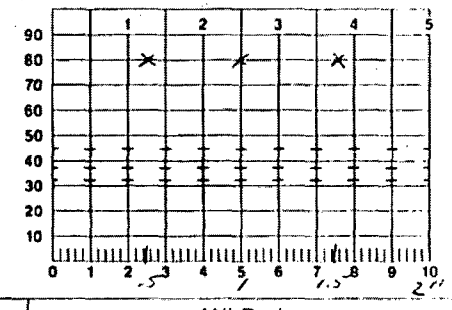
Search Unit Cable
Type BNC to Lemo Length 2x6'

Couplant
Make Sonasafe Batch# SSP-89-1-02

Thermometer
S/N: 88-081 Cal Due 1-9-93

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	80	.5
1.5	80	1.5

DAC Plot



Time/Date	2118 1-2-93		2151 1-2-93		2223 1-2-93	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	80	.5	80	.5	80	.5
1.5	80	1.5	80	1.5	80	1.5
Initials	[initials]		[initials]		[initials]	

Remarks:
Drywell liner thickness measurements
Digital utilized

Components Examined:
Bays 1, 3 & 5

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 1-3-93

NDE Request#: 92-072

N0927 (05-90)

allgood

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072
Task Description: UT Thickness		Task No.: N/A	Date: 1-8-93
Comp. Desc.: Drywell Liner	System: 187	Code/Spec.: Eng. Info.
Procedure/Rev.: 6100-GAP-7208.07 Rev. 0	Drawing No./Rev.: 36-157-29-001	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner Sign: [signature]	Print: Jon VanderLinde	ID No.: 154-83-0210	Level: II
Examiner Sign: [signature]	Print: Luis Valenzuela	ID No.: 110-44-2524	Level: II

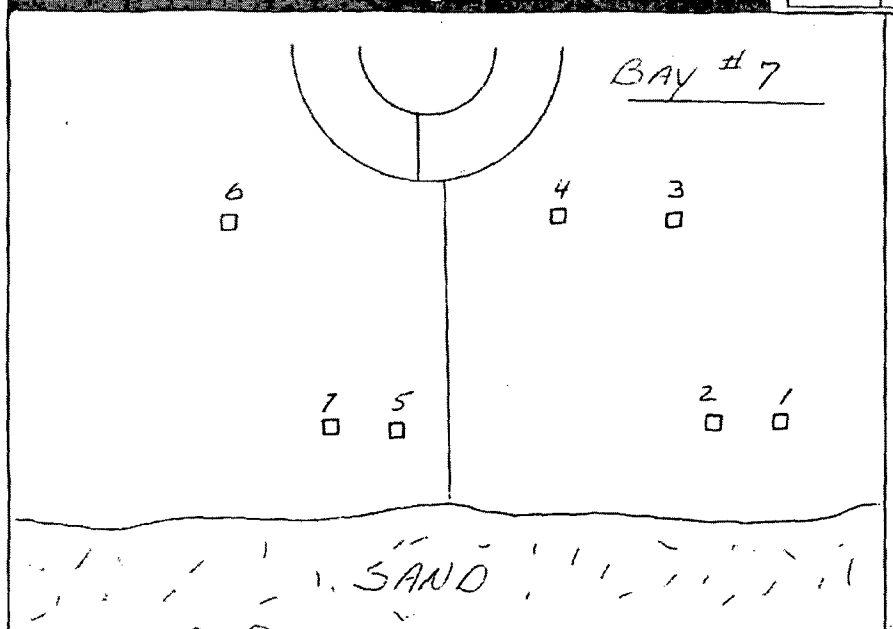
Thermometer S/N 92-065 Part Temperature 70 F D-Meter S/N 92-035
Cal. Blk. S/N 219 Cal. In: 0010 AM ____ PM
Cal. Blk. Temp. 72 F Cal. Out: 0205 AM ____ PM

Calibration Readings (Inches)

Cal. Blk.	.5	1.0	1.5			
D-Meter	.5	1.0	1.5			

Techniques: ☐ CRT ☒ D-Meter; Other ____

Position #/Reading in Inches



Drawing

	AREA		MEASUREMENT
1	D-21"	R-39"	0.92"
2	D-21"	R-32"	1.016"
3	D-10"	R-20"	0.954"
4	D-10"	R-10"	1.04"
5	D-21"	L-6"	1.03"
6	D-10"	L-23"	1.045"
7	D-21"	L-12"	1.0"

Reviewed by: [signature] Level: II Date: 1-8-93 Page 1 of 1

115455 (05/90)

GPU Nuclear

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed		Calc No.: C-1302-187-5320-024	Rev. No.: 1
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Date

Sheet No. 81 of 114

GPU Nuclear	Subject: O.C. Drywell Ext. UT Evaluation in Sandbed	Calc No.: C-1302-187-5320-024	Rev. No.: 1	Sheet No.: 82 of 114
	Originator: Mark Yekta	Reviewed by: S. C. Tumminelli		
	Date: 01/12/93			Date

all good

GPU Nuclear — Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-23
Task Description: UT Thickness		Task No.: N/A		Date: 1-7-93
Comp. Desc.: Drywell Liner	System: 157		Code/Spec.: Eng. Info.	
Procedure/Rev.: 6100-GAP 7209.07 Rev. C		Drawing No./Rev.: 3E-157-29-001 Rev. C		
Test Surface: O.C. Bay #9		Thickness: 1 1/8"	Material: C/S	
Examiner Sign: [signature]	Print: J. Vanderlinde	ID No.: 154-46038	Level: II	
Examiner Sign: [signature]	Print: Luis Valenzuela	ID No.: 116-44-2524	Level: II	

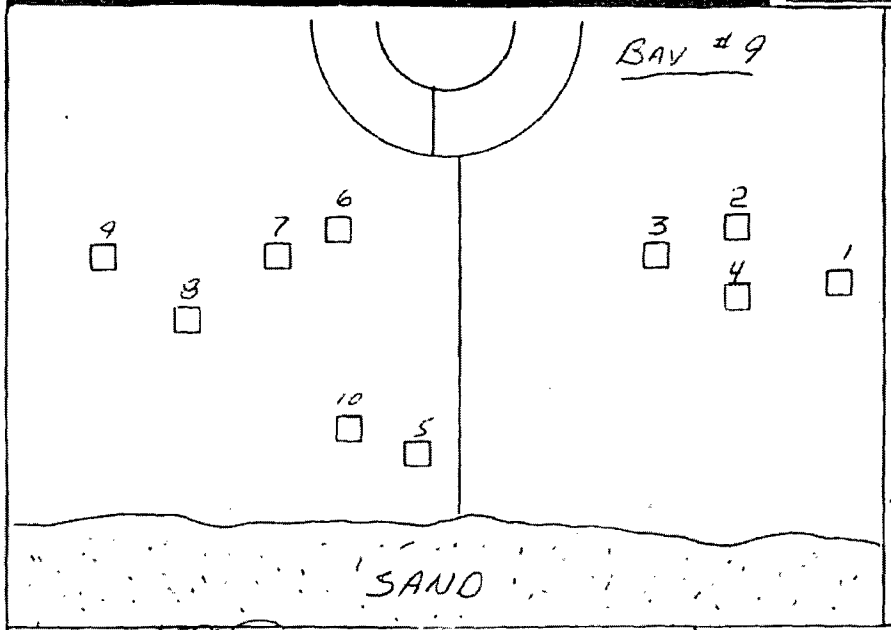
Thermometer S/N 92-008 Part Temperature 72 F D-Meter S/N 92-009
Cal. Blk. S/N 219 Cal. In: 0200 AM 0200 PM
Cal. Blk. Temp. 72 F Cal. Out: 0415 AM 0415 PM

Calibration Readings (Inches)

Cal. Blk.	.5	1.0	1.5			
D-Meter	.5	1.0	1.5			

Techniques: ☐ CRT ☒ D-Meter ☐ Other

Position #/Reading in Inches



Drawing

	AREA	MEASUREMENT
1	0-21 R-32	.960
2	0-12 R-17	.94
3	0-18 R-8	.994
4	0-21 R-17	1.020
5	0-36 L-4	.935
6	0-~~34~~16 L-30	.82
7	0-18 L-	.825
8	0-22 L-	.791
9	0-~~54~~ L-53	.832
10	0-32 L-8	.930

Reviewed by: [signature] Level: II Date: 1-8-93 Page 1 of 1

NS155 (05/90)

One Point

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☑ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-09
Task Description: UT Thickness			Task No.: N/A	Date: 12/22/92
Comp. Desc.: Drywell Liner Bay 11	System: 187		Code/Spec.: ASME Sect. III	
Procedure/Rev.: GPU: GAP-QS-4.03 Rev. 0		Drawing No./Rev.: 3E-187-29-001 Rev. 0		
Test Surface: O.D.		Thickness: 1 1/8"	Material: C/S	
Examiner	Sign: [signature]	Print: J. Vander Linde	ID No.: 154-45-0219	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-61-1802	Level: I

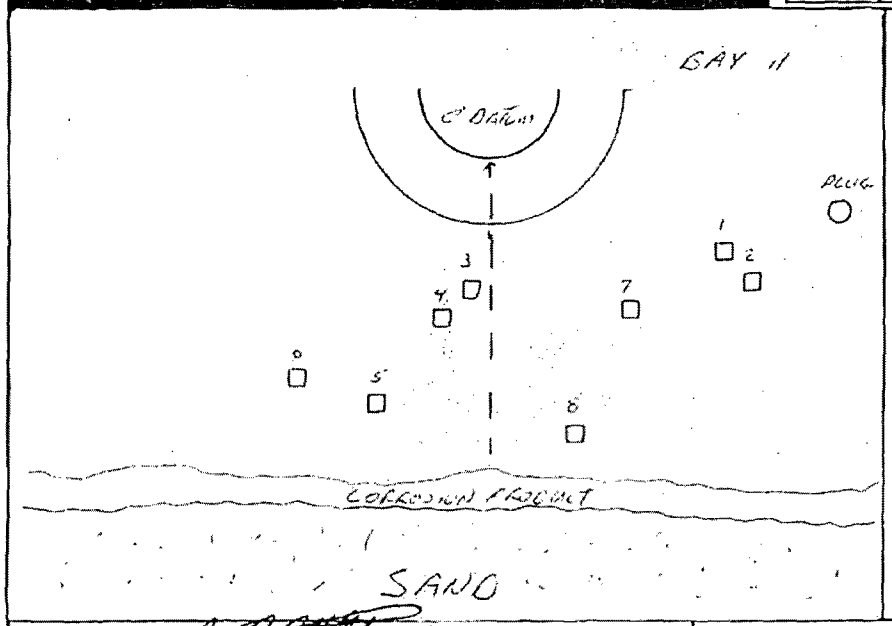
Thermometer S/N 92-005 Part Temperature 65 F D-Meter S/N 137-113
Cal. Blk. S/N 92 Cal. In: N/A AM 3:00 PM
Cal. Blk. Temp. 65 F Cal. Out: N/A AM 3:30 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0			
D-Meter	.5	.75	1.0			

Techniques: ☑ CRT ☐ D-Meter ☐ Other

Position #/Reading in Inches



Drawing

PLUG 15" down 4" right
AREA Thickness
1. 0-20" R-29" 0.71"
2. 0-25" R-32" 0.76"
3. 0-21" L-4" 0.63"
4. 0-24" L-6" 0.76"
5. 0-30" L-14" 0.64"
6. 0-27" L-22" 0.61"
7. 0-31" R-20" 0.53"
8. 0-40" R-15" 0.87"

Reviewed by: [signature] Level: III Date: 12-27-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear			
Subject O.C. Drywell Ext. UT Evaluation in Sandbed			
Originator Mark Yekta	**Date** 01/12/93	**Calc No.** C-1302-187-5320-024	**Rev. No.** 1
		Reviewed by S. C. Tumminelli	**Date**
			Sheet No. 83 of 114

GPU Nuclear	Subject: O.C. Drywell Ext. UT Evaluation in Sandbed	Calc No.: C-1302-187-5320-024	Rev. No.: 1	Sheet No.: 84 of 114
	Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Date:

ONE POINT

GPU Nuclear — Ultrasonic Thickness Data Sheet

☑ OC ☐ TMI-1 ☐ TMI-2 | Class: N/A | Item: N/A | NDE Request: 92-072 | Data Sheet No.: 92-072-10

Task Description: UT Thickness | Task No.: N/A | Date: 12/22/92

Comp. Desc.: Drywell Liner Bay 11 | System: 167 | Code/Spec.: ASME [illegible]

Procedure/Rev.: 6100-CRP-2209.07 Rev | Drawing No./Rev.: 3E-187-25-001 REO

Test Surface: O.C. | Thickness: 1 1/8" | Material: C/S

Examiner	Sign: [signature]	Print: Jonathan B. Unicke Cash	ID No.: 1349-03A	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-EH-1662	Level: II

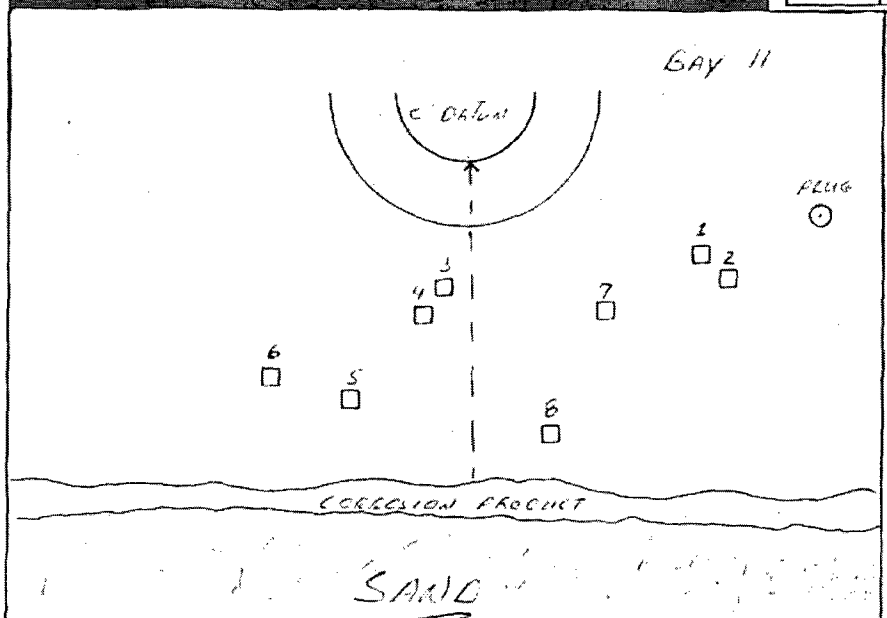
Thermometer S/N 92-055 Part Temperature 65 F D-Meter S/N 92-035
Cal. Blk. S/N 92 Cal. In: N/A AM 2:40 PM
Cal. Blk. Temp. 65 F Cal. Out: N/A AM 3:00 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0			
D-Meter	.5	.75	1.0			

Techniques: ☐ CRT ☑ D-Meter Other _____

Position #/Reading In Inches



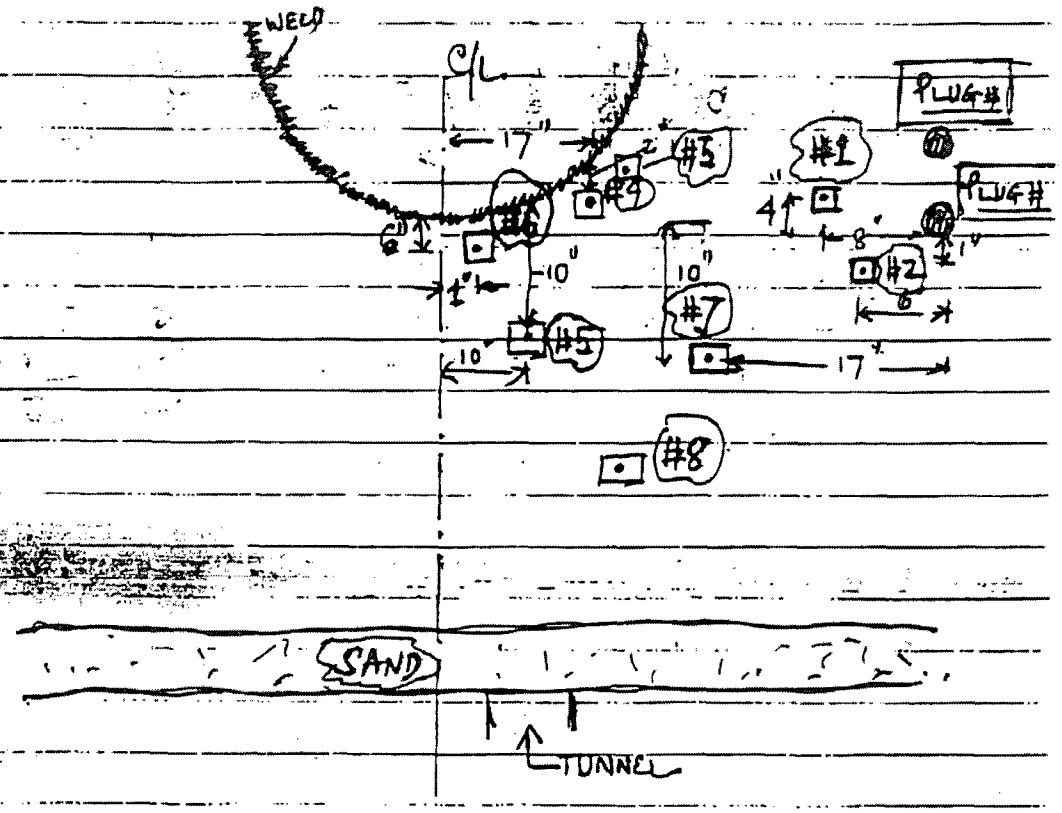
Drawing

PLUG 15" DOWN 11" RIGHT

	AREA	THICKNESS
1	0-20" R-29"	0.705"
2	0-25" R-32"	0.770"
3	0-24" 4-4"	0.832"
4	0-24" 4-6"	0.755"
5	0-32" 4-14"	0.501
6	0-27" 4-22"	0.60
7	0-31" R-20"	0.531
8	0-40" R-13"	0.860

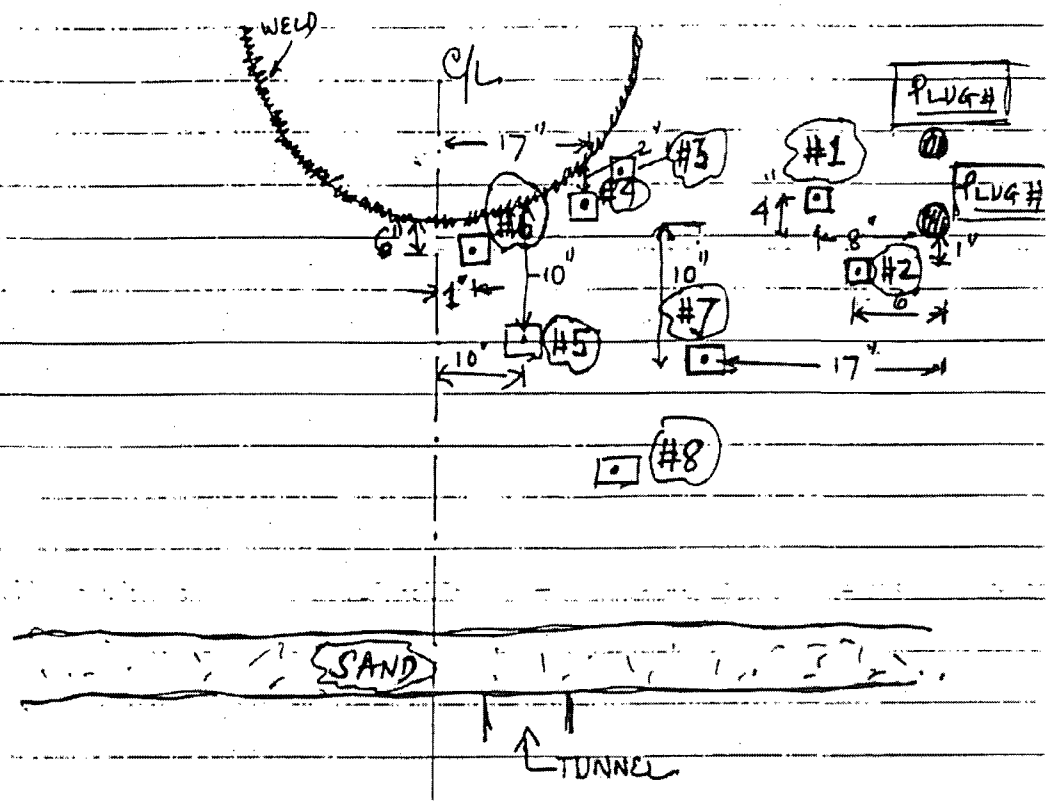
Reviewed by: [signature] Level: II Date: 12-27-92 Page 1 of 1

N5455 (05-90)



BAY-11 — UT SPOTS FOR GRINDING

NOTE: GRIND ONE SPOT AT A TIME. REMARK THE SPOT # AFTER GRINDING.



BAY-11 — UT SPOTS FOR GRINDING

NOTE: GRIND ONE SPOT AT A TIME. REMARK THE SPOT # AFTER GRINDING.

GPU Nuclear

Subject	Calc No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	87 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli	**Rev. No.** 1
Date 01/12/93		**Date**

GPU Nuclear

OC ITMI

Calibration Sheet

Cal Sheet# 14R-069

System	Component	Procedure	Rev
187	Drywell Cont Bay 11	6100-ORP-7209.07	0

	Signature	Print	Initial	ID#	Level
Examiner:	[signature]	J Ulrich Clark	[initials]	154-46-0519	II
Examiner:	Mark Bagnell	Mark F. Bagnell	MFB	555-61-1662	I

Instrument Settings
ID# 137-113
Model/Manuf Sonic 137 STRUERS

Gain
Coarse 52.2
Fine NR
Uncal NR

Sweep Circuit
Coarse 2" (Range)
Fine 0.31
Delay 1"
Screen Depth 2"

Operation (T&R)
Normal
Frequency: 2.25 MHZ
Reject: ☐Off ☐On ___ %
Filter: ☐Off ☑On 1 %
Damping: ☐Off ☑On 200 %

Rep Rate: Low Hz

Cal Standard
ID# 96
Size 4-1" Sch. 40
Thickness .5 .75 1.0
S/S CS
Temp 65 °F

System Check
☐Exit Point N/A
☐Angle +/- 2

Date 12/22/92

Search Unit
ID# M0574
Type MSEB
Freq 2 MHZ
Size 1/2"
Angle 0 Mode Long

Cal Direction
☐Axial ☐Both
☐Circ. ☑Normal

Time 15:05

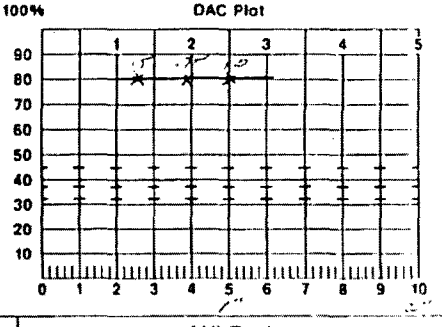
Search Unit Cable
Type Dual Line Length 2x6'

Couplant
Make Sonotrak Batch# SSA-92-1 [illegible]

Thermometer
S/N: 96-055 Cal Due 5/23/93

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	50	.5
.75	80	.75
1.0	60	1.0

DAC Plot



Time/Date	1530 / 12/22/92		/		/	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	50	.5				
.75	80	.75				
1.0	50	1.0				
Initials	[initials]					

Remarks:

Components Examined: Bay 11

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 12-27-92

NDE Request#: 92-072

N0927 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	88 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tummminelli		
Date 01/12/93			**Date**

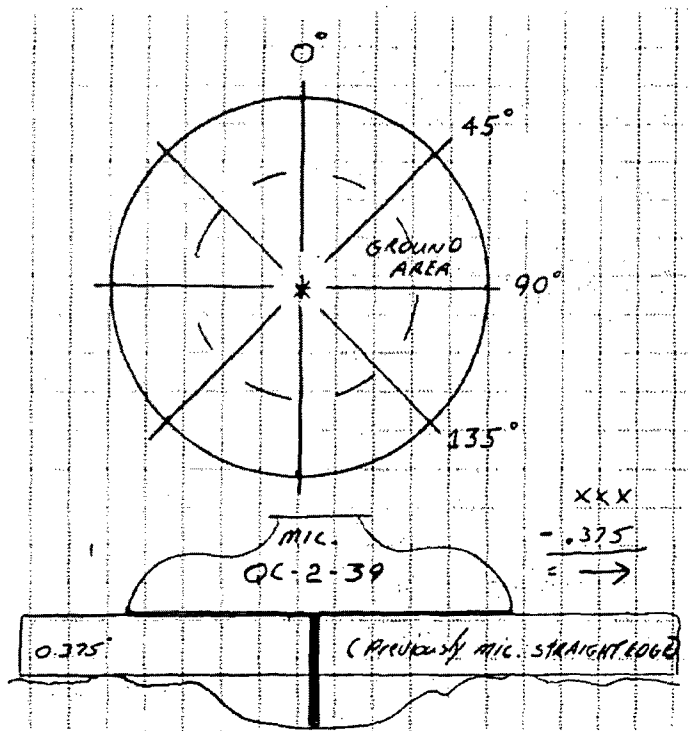
GPU Nuclear

☒ OC ☐ TMI ☐ OTHER _____

Sketch Form (with grid)

Component: DRYWELL liner SANDBED AREA	Data Sheet No.: 92-072-31
Location: BAY # 11	Drawing No.: N/A Rev.: NA

Drawing



Technique utilized for The Pit depth MEASUREMENTS

AZIMUTH

AREA	0°	45°	90°	135°
1	.289	.338	.157	.200

Prepared by:	Title: VT LV II		Date: 1/12/93
Reviewed by: Level: II	Date: 1-13-93	Page 1 of 1	NDE Request No.: 92-072

FORM 6130-QAP-7200.06 (12-83)

N5454 (05-90)

Four Points under

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: NA	Item: NA	NDE Request: 92-072	Data Sheet No.: 92-072-23
Task Description: DRYWELL CORROSION CONTROL (LINER THICKNESS)			Task No.: NA	Date: 1/8/93
Comp. Desc.: DRYWELL LINER BAY 13	System: DRYWELL		Code/Spec.: ENG. INFO.	
Procedure/Rev.: 6100-QAP-7209.01 Rev 0			Drawing No./Rev.: 3E-187-29-001	
Test Surface: O D			Thickness: 1 1/8"	Material: C S
Examiner	Sign: TM Sheerer	Print: N. H. SHERERER	ID No.: 217-58-4172	Level: II
Examiner	Sign: NA	Print: NA	ID No.: NA	Level: NA

Thermometer S/N 92-068 Part Temperature 74° F D-Meter S/N 92-009
Cal. Blk. S/N 219 Cal. In: NA AM 1220 PM
Cal. Blk. Temp. 69° F Cal. Out: NA AM 230 PM

Calibration Readings (Inches)

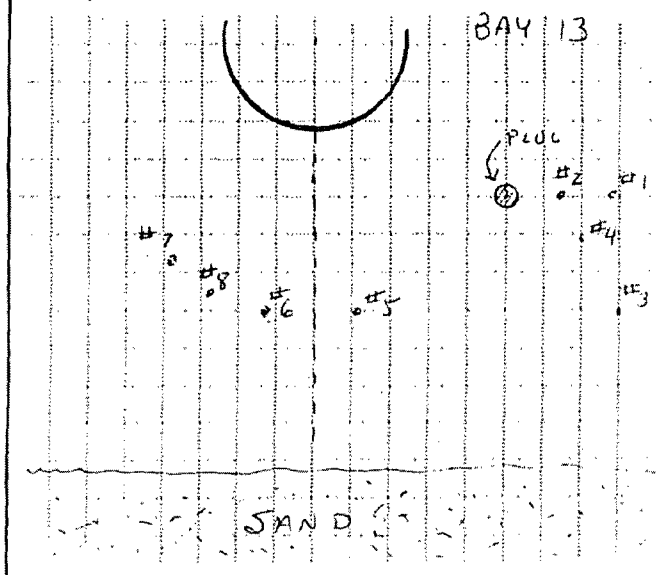
Cal. Blk.	.502"	1.499"			NA	
D-Meter	.502"	1.500"				

Techniques: ☐ CRT ☒ D-Meter
Other NA

Position #/Reading In Inches

AREA	LOCATION	THIC
1	D 6" R 46"	.814"
2	D 6" R 38"	.675" *
3	D 26" R 43"	.934"
4	D 12" R 35"	.914"
5	D 26" R 6"	.135" *
6	D 24" L 8"	.683" *
7	D 17" L 23"	.632" *
8	D 22" L 20"	.744"

Drawing



Reviewed by: [signature] Level: N/A Date: 1-8-93 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed		Calc No.: C-1302-187-5320-024	Sheet No.: 89 of 114
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Rev. No.: 1
			Date

7 Points under

GPU Nuclear

Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-0272	Data Sheet No.: 92-0272-24
Task Description: Drywell liner Thk. measurements		Task No.: N/A	Date: 1-11-93
Comp. Desc.: Drywell liner Bay 13	System: 187	Code/Spec.: N/A (ENG. INFOR)	
Procedure/Rev.: 6100-QAP-7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29 001		
Test Surface: O.D.	Thickness: 1 1/8"	Material: C.S	
Examiner Sign:	Print: J. VAN der Cudi	ID No.: 154-48-0318	Level: II
Examiner Sign:	Print: LUIS VALENZUELA	ID No.: 110-44-2524	Level: III

Thermometer S/N 92-068 Part Temperature 68 F D-Meter S/N 92-033
Cal. Blk. S/N 219 Cal. In: 1/4 AM 2225 PM
Cal. Blk. Temp. 66 F Cal. Out: 1/4 AM 2300 PM

Calibration Readings (Inches)

Cal. Blk.	.5	1.0	1.5			
D-Meter	.5	1.0	1.5			

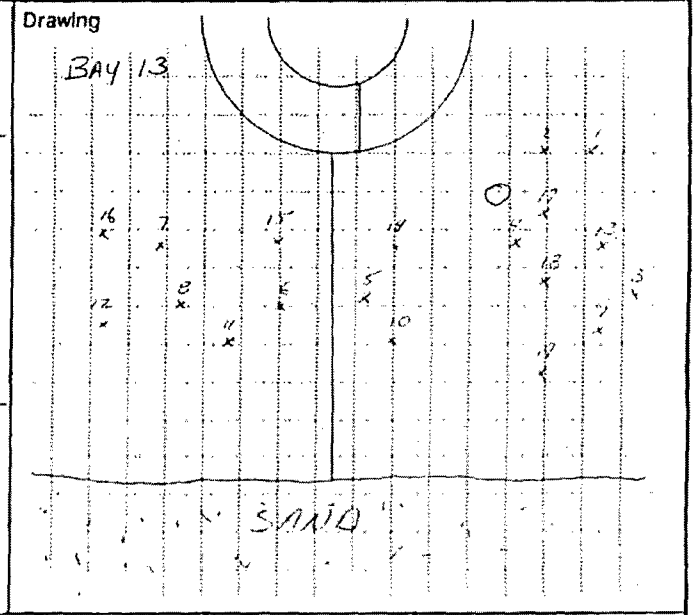
Techniques: ☐ CRT ☒ D-Meter Other _____

Position #/Reading in Inches

AREA	LOCATION	THK.
1	UP-1" R-45"	0.622"
2	UP-1" R-38"	0.725
3	0-21" R-48"	0.841"
4	0-12" R-36"	0.813"
5	0-21" R-6"	0.718"
6	0-24" L-8"	0.653"
7	0-12" L-22"	0.516"
8	0-24" L-22"	0.718"
9	0-28" R-41"	0.729"
10	0-28" R-12"	0.726"
11	0-28" L-15"	0.683"
12	0-28" L-23"	0.683"
13	0-18" R-40"	0.822"
14	0-18" R-8"	0.666"
15	0-20" L-3"	0.663"
16	0-20" L-29"	0.829"
17	0-5" R-32"	0.602"
18	0-22" R-38"	0.682"
19	0-37" R-38"	0.612"

20 not defined in 3D CAD DWG. 1/2" thk. plate
* All - Thk. measurements from exterior
Backwall on the CRT

Drawing



Reviewed by: Stan McCauley Level: III Date: 1-11-93 Page 1 of 2

N5455 (05-90)

*** Performed inference check check area of rust
[illegible]

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed	Calc No.: C-1302-187-5320-024	Rev. No.: 1	Sheet No.: 90 of 114
Originator: Mark Yekta	Reviewed by: S. C. Tumminelli		Date
Date: 01/12/93			

GPU Nuclear

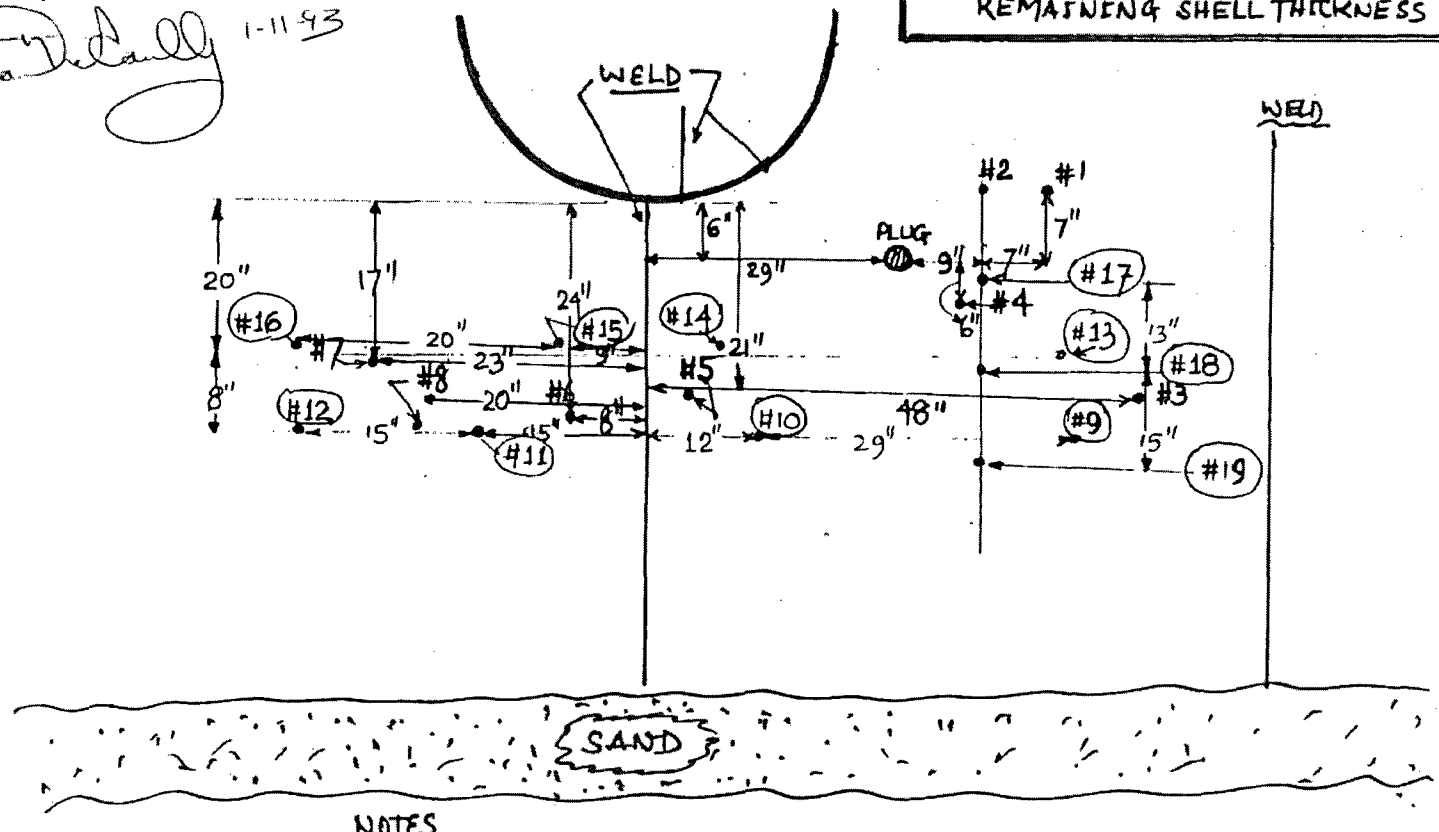
Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	91 of 114
Originator Mark Yekta	**Date** 01/12/93	**Reviewed by** S. C. Tumminelli	**Date**

BAY # 13

NOTES:

- SPOT #9 THRU 19 MARKED ON 1/10/93. SKD 1/10/93
- GRIND ABOVE SPOTS CAREFULLY AS NOT TO REDUCE SHELL THICKNESS EXCESSIVE
- UT ALL SPOTS (1 THRU 19) FOR REMAINING SHELL THICKNESS

#92-072-24
Pg 2 of 2
1-11-93



NOTES

- PLUG UNCORRODED — LOCATED IN A DEEP VALLEY.
- "TUB RING" LESS PROMINENT.
- SHELL & FLOOR NEEDS MORE CLEANING.

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	92 of 114
Originator Mark Yekta	**Date** 01/12/93	**Reviewed by** S. C. Tumminelli	**Date**

NOTE under

GPU Nuclear

Ultrasonic Thickness Data Sheet

☑ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-25
Task Description: Drywell liner Thk. measurements		Task No.: N/A	Date: 1/11/93
Comp. Desc.: Drywell liner BAY 13	System: 187	Code/Spec.: ENG. INFO
Procedure/Rev.: 6100-QAP-7209.07 Rev 0	Drawing No./Rev.: 3E-187-29-001	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S

Examiner	Sign: [signature]	Print: J. VAN DER LINDE	ID No.: 154-48-039	Level: II
Examiner	Sign: N/A	Print: N/A	ID No.: N/A	Level: N/A

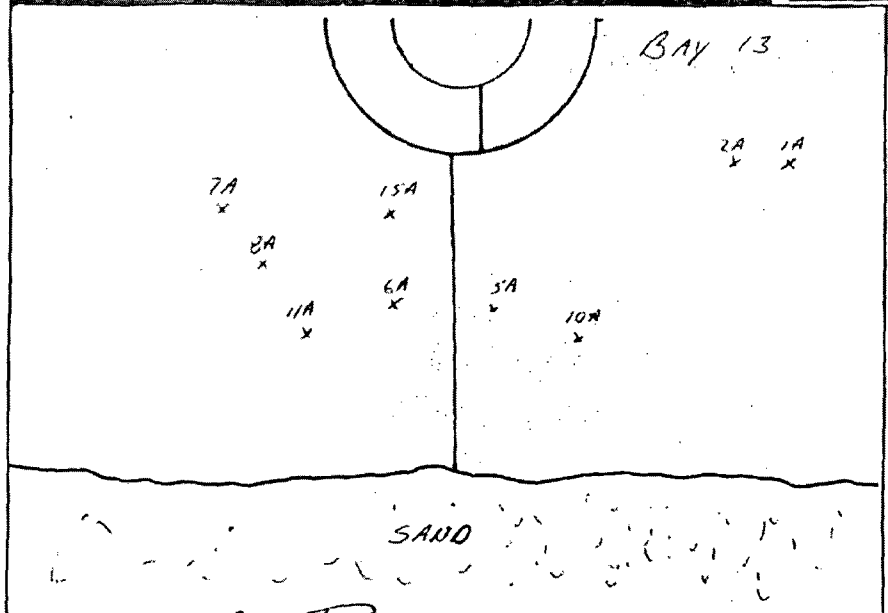
Thermometer S/N 92-068 Part Temperature 70 F D-Meter S/N 92-035
Cal. Blk. S/N 219 Cal. In: N/A AM 1030 PM
Cal. Blk. Temp. 70 F Cal. Out: N/A AM 1045 PM

Calibration Readings (Inches)

Cal. Blk.	.5	1.0	1.5	N/A		
D-Meter	.5	1.0	1.5			

Techniques: ☐ CRT ☑ D-Meter Other _____

Position #/Reading In Inches



Drawing

AREA	THICKNESS
1A	0.89"
2A	0.943"
5A	0.851"
10A	0.81"
11A	0.854"
8A	0.9"
7A	0.752"
6A	~~0.859"~~ .976"
15A	~~0.876~~ .857"

A" minimal grind area adjacent to previous grind/cut locations.

Reviewed by: [signature]	Level: III	Date: 1/11/93	Page 1 of 1

N5455 (05-90)

Done under

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-16
Task Description: Drywell liner Thickness			Task No.: N/A	Date: 1/11/93
Comp. Desc.: Drywell liner Bay 13	System: 187		Code/Spec.: Eng. Info.	
Procedure/Rev.: 6100-QAP 7208.07 Rev. 0		Drawing No./Rev.: 3E-187-29-001		
Test Surface: O.D		Thickness: 1 1/8"	Material: c/s	
Examiner Sign: [signature]	Print: J. Van der Linde	ID No.: 154-48-0319	Level: II	
Examiner Sign: N/A	Print: N/A	ID No.: N/A	Level: N/A	

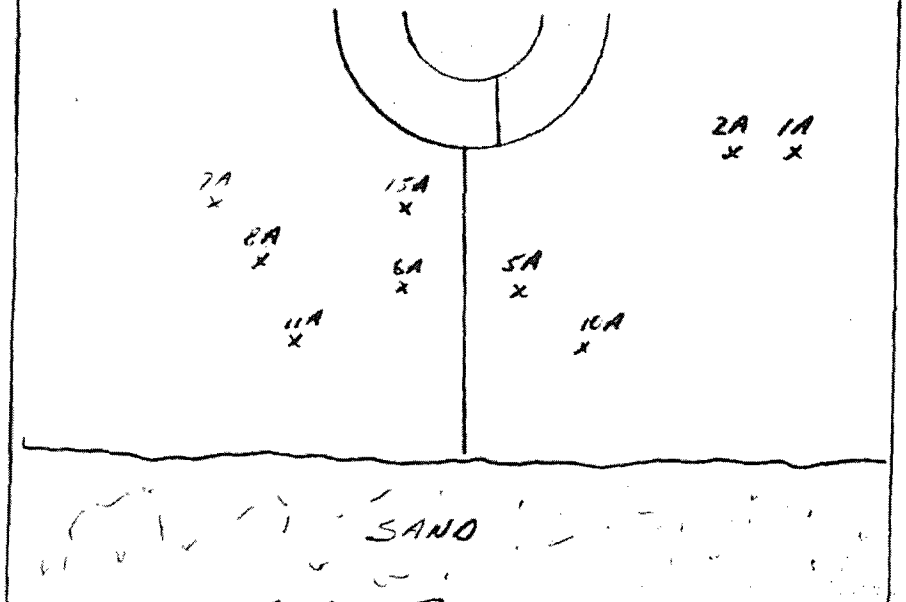
Thermometer S/N 92-068 Part Temperature 70 F D-Meter S/N 137-113
Cal. Blk. S/N 219 Cal. In: N/A AM 1032 PM
Cal. Blk. Temp. 70 F Cal. Out: N/A AM 1105 PM

Calibration Readings (Inches)

Cal. Blk.	.5	1.0	1.5		N/A	
D-Meter	.5	1.0	1.5			

Techniques: ☒ CRT ☒ D-Meter Other ____

Position # Reading in Inches



Drawing

AREA	Thickness
1A	0.88
2A	0.9
5A	0.81
10A	0.82
11A	0.83
8A	0.89
7A	0.76
6A	0.97
15A	0.85

"A" minimal grind areas adjacent to previous grind/UT locations

Reviewed by: J R [illegible] Level: III Date: 1-11-93 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	93 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear

Calibration Sheet

Cal Sheet# 14R-113

System	Component	Procedure	Rev
187	BAY 13 LINER	6100-QAP-7209.07	0

Examiner:	Signature:	Print: J. VanderLinde	Initial:	ID# 154-93-0019	Level II
Examiner:	Signature: N/A	Print: N/A	Initial: N/A	ID# N/A	Level N/A

Instrument Settings
ID# 137-113
Model/Manuf SONIC 137 STAVELY

Gain
Coarse 42.6
Fine N/A
Uncal N/A

Sweep Circuit
Coarse 2" (Range)
Fine vel. 0.224
Delay 0.365"
Screen Depth 2"

Operation
(T&R) Normal
Frequency: 5 MHZ
Reject: ☐Off ☑On %
Filter: ☐Off ☑On 1 %
Damping: ☐Off ☑On 100 %

Rep Rate: 280 Hz

Cal Standard
ID# 219
Size N/A Sch. N/A
Thickness .5 to 1.5"
S/S (CS)
Temp 70 °F

System Check
☐Exit Point N/A
☐Angle +/- 2

Date 1/11/93

Search Unit
ID# 003264
Type KBA GAMMA
Freq 5 MHZ
Size .25
Angle 0 Mode Long.

Cal Direction
☐Axial ☐Both
☐Circ. ☑Normal

Time 1032 AM

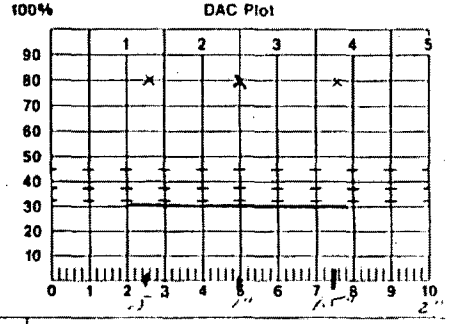
Reflector	Amplitude % of FSH	Screen Reading In Inches
.5	80	.5
1.0	80	1.0
1.5	80	1.5

Search Unit Cable
Type SIR contained Length 3x6'

Couplant
Make Soundsafe Batch# SIP 89-1-02

Thermometer
S/N: 92-058 Cal Due 5/24/93

DAC Plot



Time/Date	1105AM 1/11/93		1		1	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	80	.5				
1.0	80	1.0				
1.5	80	1.5				
Initials						

Remarks:
Digital utilized
Gate at 30% FSH
Refer to UT Thickness
Data sheet 92-072-26

Components Examined:
Drywell liner Bay 13

ANI Review

Technical Review
Reviewed By
Level Date 1-11-93

NDE Request#: 92-072

N0927 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	94 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

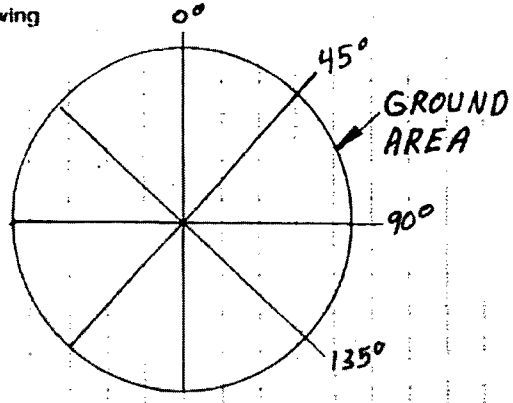
GPU Nuclear

☒ OC ☐ TMI ☐ OTHER _____

Sketch Form (with grid)

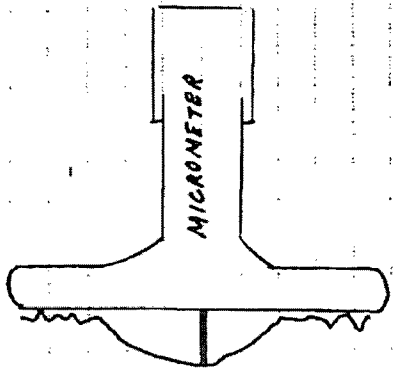
Component: DRY WELL LINEAR	Data Sheet No.: 92-072 ~~24~~ 27
Location: BAY 13	Drawing No.: N/A — Rev.: N/A

Drawing



UT READING LOCATIONS	0°	45°	90°	135°
1	.330	.382	.346	.346
2	.312	.377	.360	.393
5	.150	.193	.230	.298
6	.327	.339	.290	.247
7	.241	.279	.260	.239
8	.324	.245	.262	.279
10	.186	.173	.255	.229
11	.240	.231	.271	.283
15	.288	.277	.239	.288

DEPTH MICROMETER USED QC-2-39
VERIFIED ON BLOCK 219 & 207



TECHNIQUE USED TO DETERMINE DETH OF GROUND AREAS

Prepared by:		Title: VT LEVEL II	Date: 1-11-93
Reviewed by:	Level: II — Date: 1-13-93	Page 1 of 1	NDE Request No.: 92-072

FORM 6130-QAP-7200.08 (12-83)

N5454 (05-90)

GPU Nuclear

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed		Calc No.: C-1302-187-5320-024	Sheet No.: 95 of 114
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Rev. No.: 1 — Date

GPU Nuclear			
Subject: O.C. Drywell Ext. UT Evaluation in Sandbed			
Originator: Mark Yekta	Date: 01/12/93	Calc No.: C-1302-187-5320-024	Rev. No.: 1
		Reviewed by: S. C. Tumminelli	Date
			Sheet No.: 96 of 114

two points?

GPU Nuclear — Ultrasonic Thickness Data Sheet

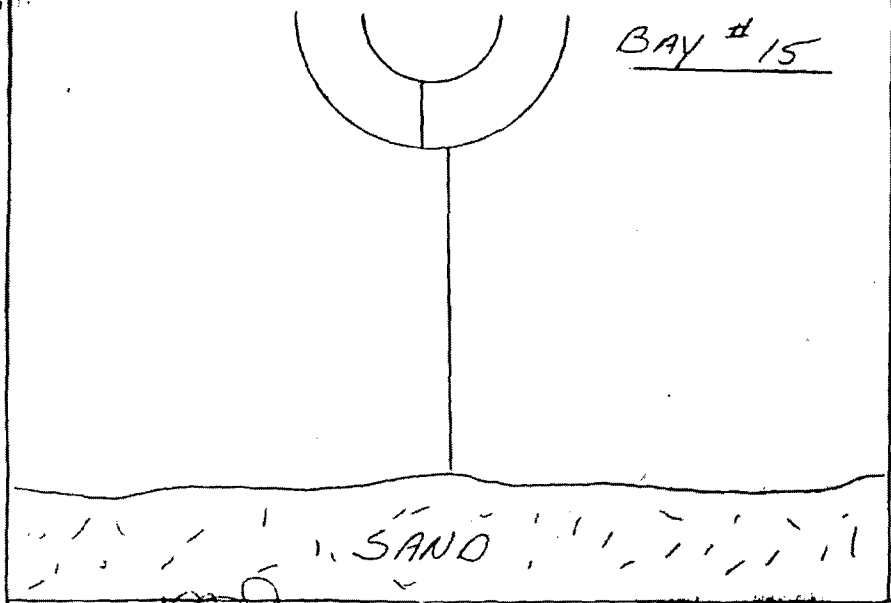
☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072
Data Sheet No.: 92-072-31			
Task Description: UT THICKNESS		Task No.: N/A	Date: 1-8-93
Comp. Desc.: Drywell Liner	System: 187		Code/Spec.: ENG. INFO.
Procedure/Rev.: 6100-QAP-7209.07 Rev. 0		Drawing No./Rev.: 3E-187-29-001	
Test Surface: O.D.		Thickness: 1 1/8"	Material: C/S
Examiner Sign: [signature]	Print: JON VAN DER LINDE	ID No.: 154-43-0319	Level: II
Examiner Sign: [signature]	Print: LUIS VALENZUELA	ID No.: 110-44-1524	Level: II

Thermometer S/N 92-068 Part Temperature 70 F D-Meter S/N 92-035
Cal. Blk. S/N 218 Cal. In: 0020 AM ____ PM
Cal. Blk. Temp. 72 F Cal. Out: 0205 AM ____ PM

Calibration Readings (Inches)

Cal. Blk.	.5	1.0	1.5			
D-Meter	.5	1.0	1.5			

Techniques: ☐ CRT ☒ D-Meter; Other ____



Drawing

	AREA	MEASUREMENT
1	0-12" R-26"	0.788" *
2	0-22" R-24"	0.829"
3	0-33" R-17"	0.932"
4	0-33" R-9"	0.795"
5	0-26" L-3	0.85"
6	0-6" L-8"	0.794"
7	0-24" L-17"	0.808"
8	0-24" L-36"	0.77"
9	0-36" L-40"	0.762" *
10	0-24" L-48"	0.86"
11	0-24" L-65"	0.825"

Reviewed by: [signature] Level: II Date: 1-8-93 Page 1 of 1

NE 455 (05-90)

GPU Nuclear

Subject	Calc No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	97 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli	**Rev. No.** 1
Date 01/12/93		**Date**

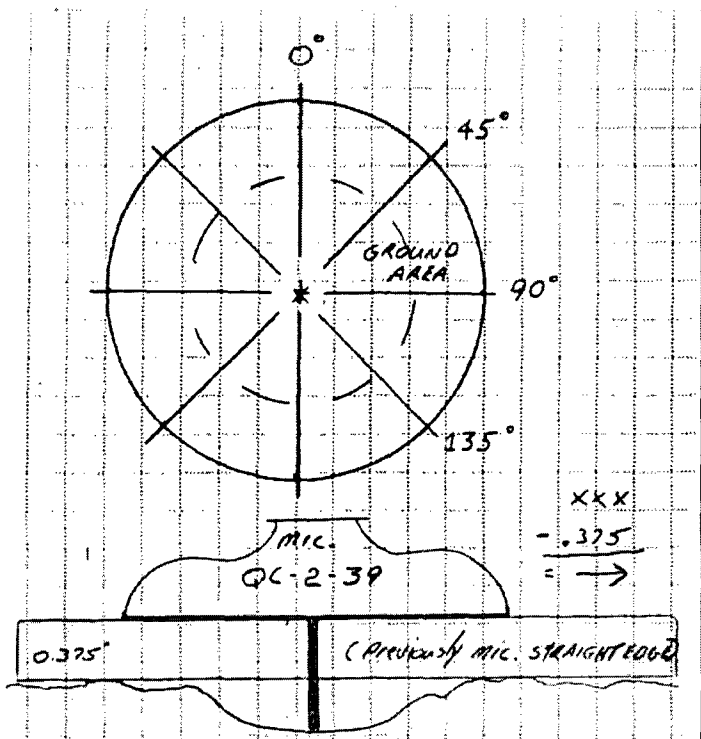
GPU Nuclear

☒ OC ☐ TMI ☐ OTHER _____

Sketch Form (with grid)

Component: DRYWELL liner SANDBED AREA	Data Sheet No.: 92-072-3D
Location: BAY # 15	Drawing No.: N/A Rev.: N/A

Drawing



Technique utilized for The Pit depth MEASUREMENTS

AZIMUTH

AREA	0°	45°	90°	135°
9	.356	.350	.359	.282

Prepared by:	Title: VT LV II		Date: 1/12/93
Reviewed by: Level: II	Date: 1-13-93	Page 1 of 1	NDE Request No.: 92-072

FORM 6130-QAP-7200.08 (12-83)

All above .736

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-01
Task Description: UT Thickness Measurements			Task No.: N/A	Date: 12/5/92
Comp. Desc.: Drywell Liner BAY 17	System: 187		Code/Spec.: ASME Sect. VIII	
Procedure/Rev.: 6100-SNI-7209.07 Rev. 0		Drawing No./Rev.: 3E-187-29-001 Rev. 0		
Test Surface: O.D.		Thickness: 1 1/8"	Material: C/S	
Examiner	Sign: [signature]	Print: Jonathan Van der Linde	ID No.: 154-48-0219	Level: II
Examiner	Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-81-1802	Level: I

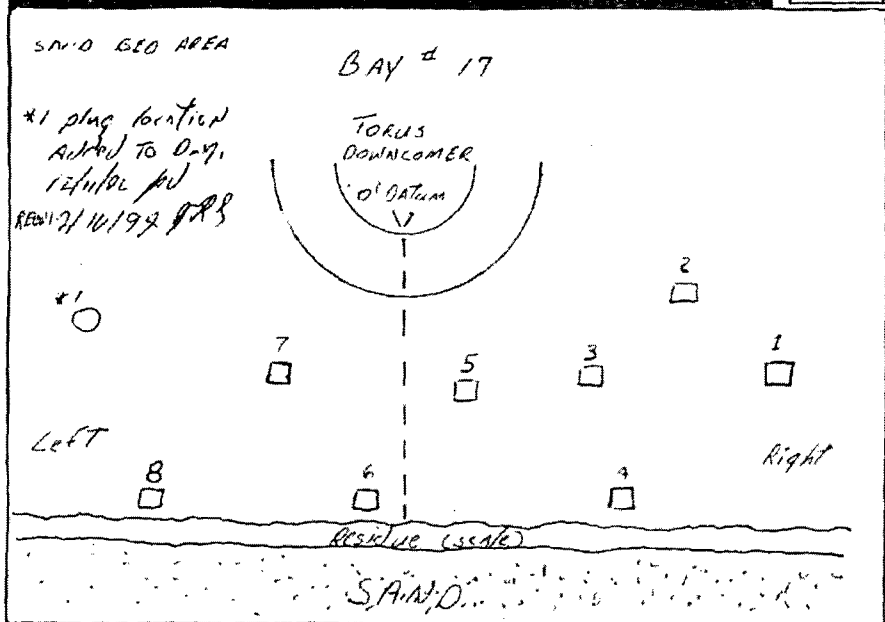
Thermometer S/N 92-057 Part Temperature 68 F D-Meter S/N 132-113
Cal. Blk. S/N 218 Cal. In: 9:10 AM N/A PM
Cal. Blk. Temp. 68 F Cal. Out: 9:36 AM N/A PM

Calibration Readings (Inches)

Cal. Blk.	0.5"	0.75"	1.0"	1.25"	1.5"	N/A
D-Meter	0.5"	0.75"	1.0"	1.25"	1.5"	N/A

Techniques: ☒ CRT ☒ D-Meter Other Sonic 132

Position #/Reading in Inches



Drawing

AREA	*Position	**UT Measurement
1	D-30" R-52"	0.94"
2	D-12" R-42"	1.16"
3	D-22" R-24"	0.92"
4	D-52" R-30"	1.02"
5	D-36" R-12"	0.94"
6	D-52" L-6" / Nozzle	1.01"
7	D-36" L-24"	0.99"
8	D-52" L-40"	1.03"

*Approximate position measurements
D: Down R: Right L: Left

** uniform back wall reflection indicates uniform surface at I.D. of liner.

Reviewed by: [signature] Level: III Date: 12-5-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	98 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	99 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear

Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-04
Task Description: UT Thickness		Task No.: N/A	Date: 12/14/92
Comp. Desc.: Drywell Liner Bay 12	System: 187	Code/Spec.: ASME Sect VIII
Procedure/Rev.: 6100 ADM. 7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner	Sign: [signature]	Print: Jonathan Vanderlinde	ID No.: 154-40-038	Level: II
Examiner	Sign: N/A	Print: N/A	ID No.: N/A	Level: N/A

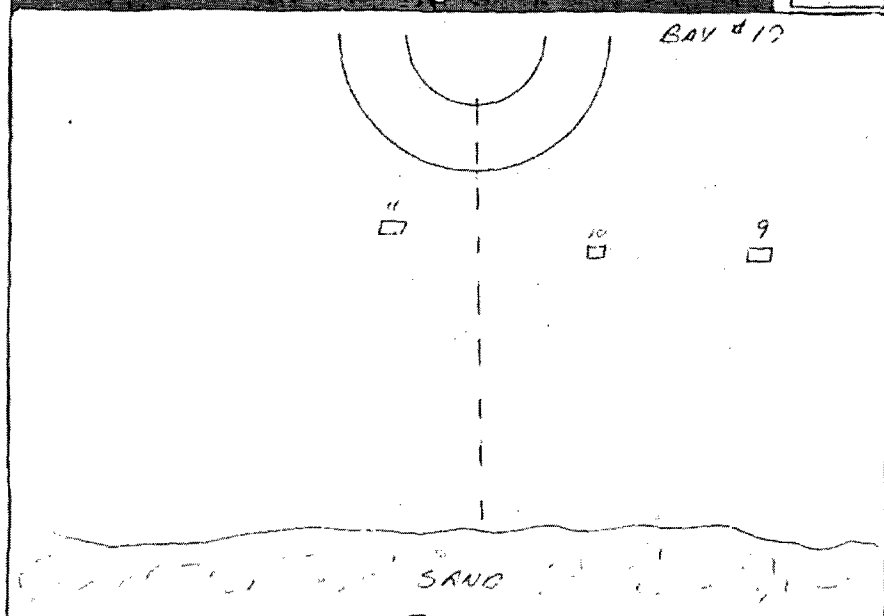
Thermometer S/N 92-057 Part Temperature 68 F D-Meter S/N 137-113
Cal. Blk. S/N 88 Cal. In: N/A AM 1:00 PM
Cal. Blk. Temp. 68 F Cal. Out: N/A AM 1:32 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	N/A		
D-Meter	.5	.75	1.0			

Techniques: ☒ CRT ☒ D-Meter Other _____

Position #/Reading in Inches



Drawing

BREAK		Thickness
9	0.27" R-30"	0.76"
10	0.26" R-11"	0.73"
11	0.21" R-12"	0.76"

Performed after sandblasting grinding

Reviewed by: [signature]	Level: III	Date: 12-16-92	Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	100 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072 06
Task Description: UT Thickness		Task No.: N/A	Date: 12/14/92
Comp. Desc.: Drywell liner Bay 17	System: 187	Code/Spec.: ASME Sect VIII
Procedure/Rev.: 6100-CDP-7200.03 Rev. 0	Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner Sign: [signature]	Print: J. Vancker Linde	ID No.: 154-48-0319	Level: II
Examiner Sign: N/A	Print: N/A	ID No.: N/A	Level: N/A

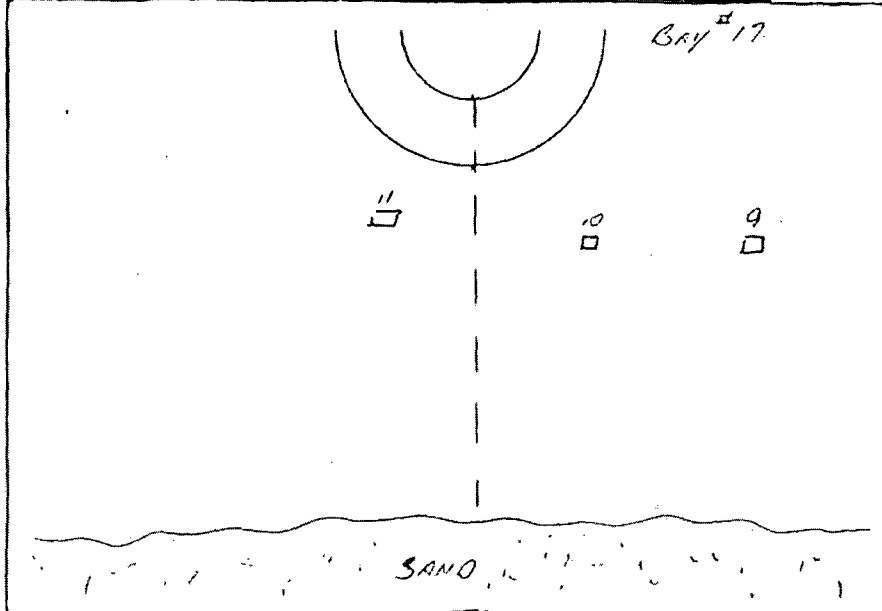
Thermometer S/N 92-057 Part Temperature 68 F ~~D-Meter S/N~~ 92-010
Cal. Blk. S/N 58 Cal. In: N/A AM 1:05 PM
Cal. Blk. Temp. 68 F Cal. Out: N/A AM 1:21 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	N/A		
D-Meter	.5	.75	1.0			

Techniques: ☒ CRT ☒ D-Meter ☐ Other _____

Position #/Reading in Inches



Drawing

Area		Thickness
9	0.27" R-35"	0.72"
10	0.26" R-11"	0.53"
11	0.24" L-12"	0.77"

Performed AFTER additional grinding
High noise level

Reviewed by:	Level:	Date:	Page 1 of 1
[signature]	III	12-16-92	

N5455 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	101 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear — Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-05
Task Description: UT Thickness Measurements			Task No.: N/A	Date: 12/11/92
Comp. Desc.: Drywell Liner Bay 187	System: 187		Code/Spec.: ASME Sect. VIII	
Procedure/Rev.: 6100-OAP-7209.07 Rev. 0		Drawing No./Rev.: 3E-187-29-001 Rev. 0		
Test Surface: O.D.		Thickness: 1 1/8"	Material: C/S	
Examiner	Sign: [signature]	Print: Jonathan VanderLinde	ID No.: 154-48-0319	Level: II
Examiner	Sign: [signature]	Print: MARK F. BAGNELL	ID No.: 553-81-1802	Level: I

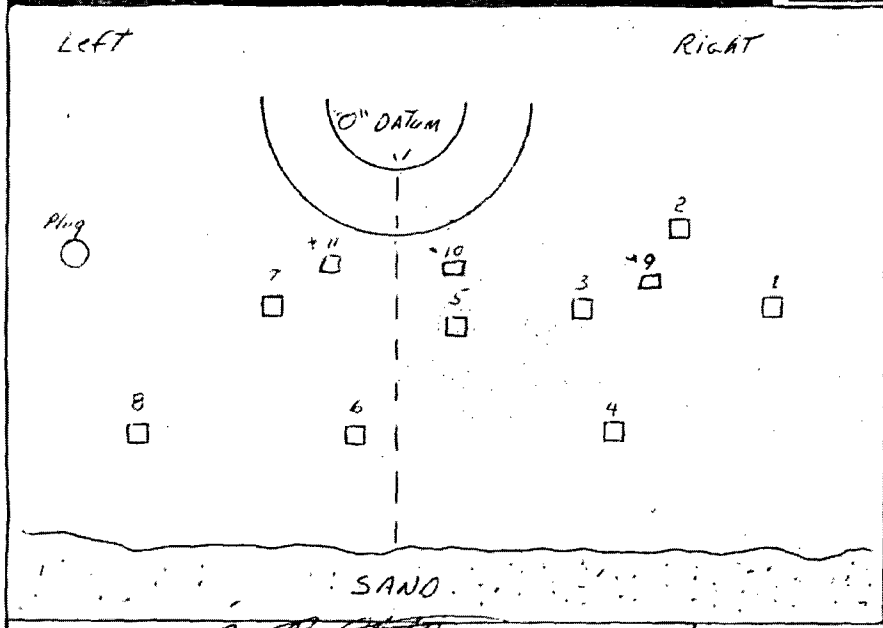
Thermometer S/N 87-053 Part Temperature 72 F D-Meter S/N 92-010
Cal. Blk. S/N 88 Cal. In: 1145 AM N/A PM
Cal. Blk. Temp. 72 F Cal. Out: N/A AM 1225 PM

Calibration Readings (Inches)

Cal. Blk.	0.5"	0.75"	1.0"	N/A	N/A	N/A
D-Meter	0.5"	0.75"	1.0"			

Techniques: ☐ CRT ☒ D-Meter; Other _____

Position #/Reading in Inches



Drawing

AREA	Position		Thickness
1	0-30"	R-52"	0.916"
2	0-12"	R-42"	1.15"
3	0-32"	R-28"	0.898"
4	0-52"	R-30"	0.951"
5	0-36"	R-12"	0.913"
6	0-52"	L-6"	0.992"
7	0-36"	L-26"	0.97"
8	0-52"	L-40"	0.99"
Plug	0-22"	L-58"	
*9	L-27"	A-30"	~~0.83"~~ [illegible]
*10	0-26"	R-11"	~~0.843"~~ [illegible]
*11	0-21"	L-12	~~0.762"~~ [illegible]

*AREAS Dished - High Noise levels unable to achieve accuracy

Reviewed by: [signature] Level: III Date: 12-16-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear			
Subject: O.C. Drywell Ext. UT Evaluation in Sandbed		Calc No.: C-1302-187-5320-024	Rev. No.: 1
Originator: Mark Yekta	Date: 01/12/93	Reviewed by: S. C. Tumminelli	Date
			Sheet No.: 102 of 114

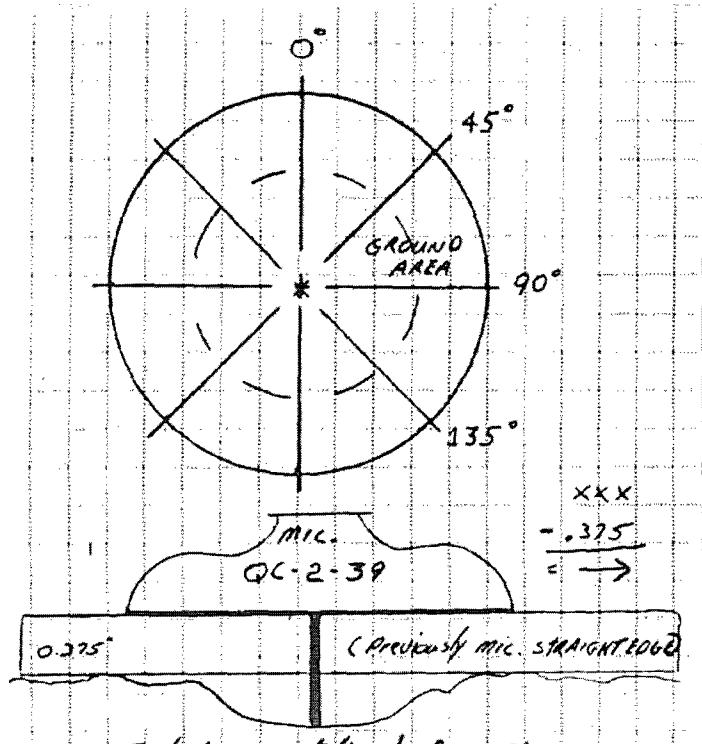
GPU Nuclear

☒ OC ☐ TMI ☐ OTHER _____

Sketch Form (with grid)

Component: DRYWELL liner SANDBED AREA	Data Sheet No.: 92-072-29
Location: BAY # 17	Drawing No.: N/A Rev.: N/A

Drawing



Technique utilized for The pit depth MEASUREMENTS

AZIMUTH

AREA	0°	45°	90°	135°
9	.368	.407	.289	.342

Prepared by:	Title: VT LV II	Date: 1/12/93	
Reviewed by:	Level: II	Date: 1-13-93	Page 1 of 1	NDE Request No.: 92-072

FORM 6130-OAP-7200.06 (12-83)

N5454 (05-90)

all Above 0.736

GPU Nuclear — **Ultrasonic Thickness Data Sheet**

☒ OC ☐ TMI-1 ☐ TMI-2	Class: nh	Item: nh	NDE Request: 92-072	Data Sheet No.: 92-072-02
Task Description: UT Thickness		Task No.: nh	Date: 12/5/92
Comp. Desc.: Drywell Liner Bay 19	System: 187	Code/Spec.: ASME Sect VIII
Procedure/Rev.: 6100-ANP-7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner Sign: [signature]	Print: Jonathan Vanche Linde	ID No.: 154-46-0319	Level: II
Examiner Sign: [signature]	Print: Mark F. Bagnell	ID No.: 553-81-1802	Level: I

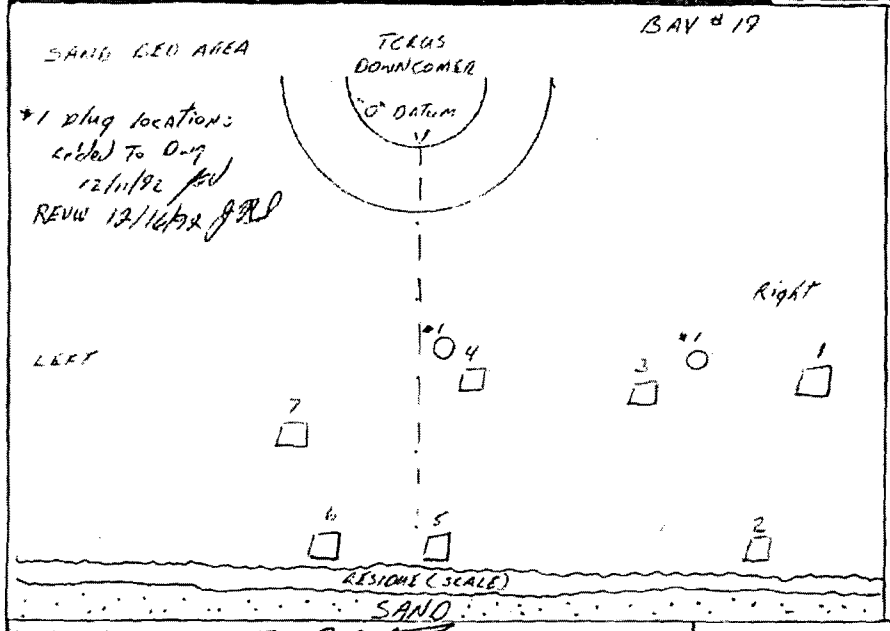
Thermometer S/N 92-057 Part Temperature 63 F D-Meter S/N 137-113
Cal. Blk. S/N 212 Cal. In: 10:20 AM nh PM
Cal. Blk. Temp. 68 F Cal. Out: 10:36 AM nh PM

Calibration Readings (Inches)

Cal. Blk.	0.5	0.75	1.0	1.25	1.5	
D-Meter	0.5	0.75	1.0	1.25	1.5	

Techniques: ☒ CRT ☒ D-Meter
Other Sonic 137

Position #/Reading in Inches



Drawing

AREA	*POSITION	UT MEASUREMENT**
1	D-30" R-70"	0.94"
2	D-52" R-66"	0.96"
3	D-32" R-49"	0.98"
4	D-32" R-11"	0.99"
5	D-53" R-2"	0.95"
6	D-52" L-6"	0.96"
7	D-39" L-12"	0.98"

* Position measurements are approximate

** uniform backwall reflection indicates a uniform surface at the I.D. of liner

Reviewed by: [signature] Level: III Date: 12-5-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed			
Originator: Mark Yekta	Date: 01/12/93	Calc No.: C-1302-187-5320-024	Rev. No.: 1
Reviewed by: S. C. Tumminelli			Sheet No.: 103 of 114
			Date:

GPU Nuclear

Subject	Originator	Date	Calc No.	Reviewed by	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	Mark Yekta	01/12/93	C-1302-187-5320-024	S. C. Tumminelli	1	104 of 114

GPU Nuclear — Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-03
Task Description: UT Thickness		Task No.: N/A	Date: 12/14/92
Comp. Desc.: Drywell Liner Bay # 19	System: 187	Code/Spec.: ASME Sect III
Procedure/Rev.: 6100-QAP-7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner Sign: [signature]	Print: J. Vaughn Linde	ID No.: 154-48-03/9	Level: II
Examiner Sign: N/A	Print: N/A	ID No.: N/A	Level: N/A

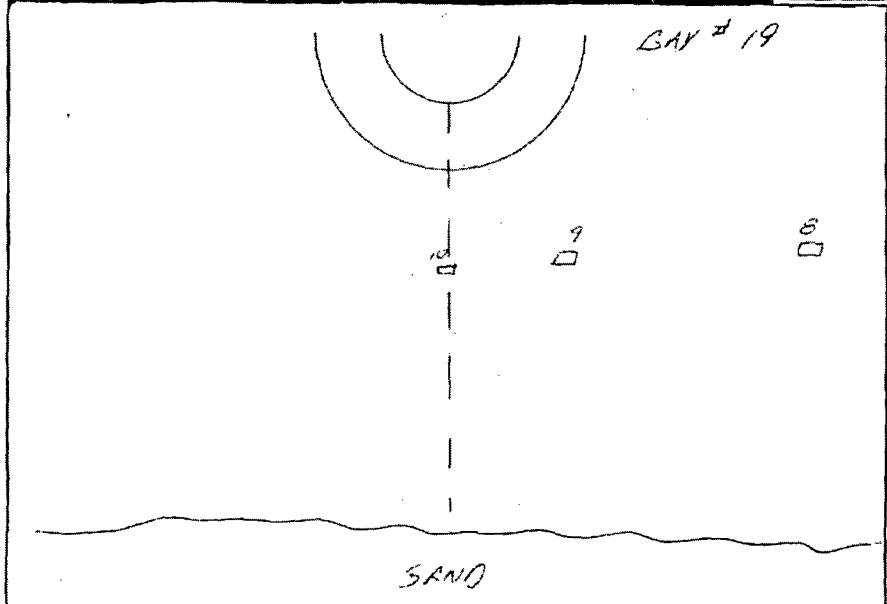
Thermometer S/N 92-057 Part Temperature 68 F D-Meter S/N 137-113
Cal. Blk. S/N 23 Cal. In: N/A AM 1:30 PM
Cal. Blk. Temp. 68 F Cal. Out: N/A AM 3:00 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0			
D-Meter	.5	.75	1.0			

Techniques: ☒ CRT ☒ D-Meter ☐ Other

Position #/Reading in Inches



Drawing

Point		Thickness
8	0.16" R 63"	0.957
9	0.18" R 12"	0.795
10	0.19" R 0"	0.806

Performed after additional grinding

Reviewed by: [signature] Level: III Date: 12-16-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	105 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

GPU Nuclear — Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-032	Data Sheet No.: 92-032-05
Task Description: CAT Thickness		Task No.: N/A	Date: 12/14/92
Comp. Desc.: Drywell liner Bay 19	System: 187	Code/Spec.: ASME Sect VIII
Procedure/Rev.: 6100-ONP-7209.07 Rev. 0	Drawing No./Rev.: 3E-187-29-001 Rev. 0	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner	Sign: [signature]	Print: J. Vanichelinda	ID No.: 154-48-0519	Level: II
Examiner	Sign: N/A	Print: N/A	ID No.: N/A	Level: N/A

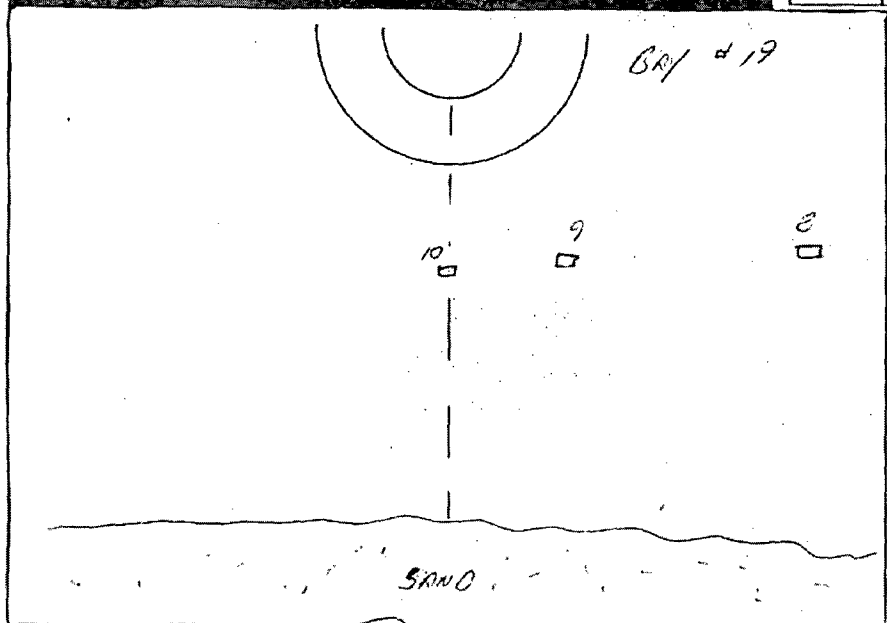
Thermometer S/N 92-057 Part Temperature 68 F D-Meter S/N 92-010
Cal. Blk. S/N 68 Cal. In: N/A AM 1:32 PM
Cal. Blk. Temp. 68 F Cal. Out: N/A AM 2:05 PM

Calibration Readings (Inches)

Cal. Blk.	.5	.75	1.0	N/A	N/A	
D-Meter	.5	.75	1.0			

Techniques: ☒ CRT ☒ D-Meter Other _____

Position #/Reading in Inches



Drawing

Area		Thickness
8	D-16" R-6.5"	0.953
9	D-16" R-12"	0.776
10	D-19" R-0"	0.790

Performed after additional grinding

thick noise loop

Reviewed by: [signature]	Level: III	Date: 12-16-92	Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject	Calc No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	106 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli	**Rev. No.** 1
Date 01/12/93		**Date**

GPU Nuclear — Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-07
Task Description: UT THICKNESS		Task No.: N/A	Date: 12-11-92
Comp. Desc.: DRYWELL LINER BAY 19	System: 187	Code/Spec.: ASME SEC VIII
Procedure/Rev.: GIGG-QAP 7209.07 REV 0	Drawing No./Rev.: 3E-187-27-001 REV B	
Test Surface: O.D.	Thickness: 1 1/8"	Material: C/S
Examiner Sign: [signature]	Print: JONATHAN VANDERCLUTE	ID No.: 154-48-0319	Level: II
Examiner Sign: [signature]	Print: MARK F. BAGNELL	ID No.: 552-81-1802	Level: I

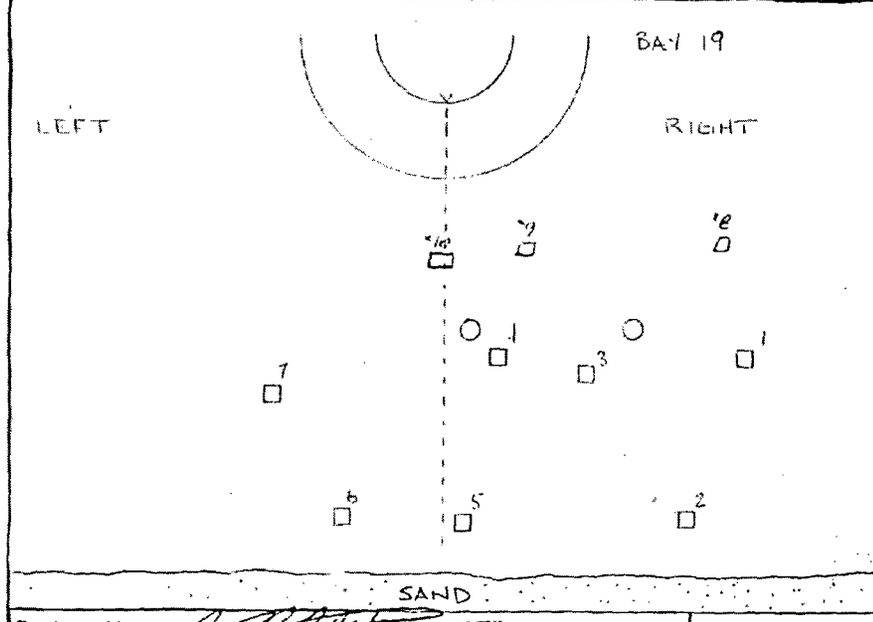
Thermometer S/N 81-053 Part Temperature 72° F D-Meter S/N 92-010
Cal. Blk. S/N 86 Cal. In: N/A AM 12:45 PM
Cal. Blk. Temp. 72° F Cal. Out: N/A AM 12:15 PM

Calibration Readings (Inches)

Cal. Blk.	0.5	0.75	1.0	N/A	N/A	N/A
D-Meter	0.5	0.75	1.0	N/A	N/A	N/A

Techniques: ☐ CRT ☒ D-Meter
Other N/A

Position #/Reading in Inches



Drawing

AREA	POSITION	MEASUREMENT
1	D 20" R 70"	0.132"
2	D 52" R 66"	0.124"
3	D 25" R 49"	0.155"
4	D 32" R 11"	0.145"
5	D 52" R 2"	0.150"
6	D 52" L 6"	0.160"
7	D 31" L 12"	0.165"
* 8	D 16" R 63"	0.160" surface rough
* 9	D 18" R 12"	0.170" surface rough
* 10	D 41" 0"	0.181" surface rough
PLUG #1	D 21" R 6"	
PLUG #2	D 21" R 55"	

* surface chisled unable to achieve accurate measurement

Reviewed by: [signature] Level: II Date: 12-16-92 Page 1 of 1

NS455 (05-90)

GPU Nuclear

Subject	Originator	Date
O.C. Drywell Ext. UT Evaluation in Sandbed	Mark Yekta	01/12/93

Calc No.	Reviewed by	Date
C-1302-187-5320-024	S. C. Tummineli	

Rev. No.	Sheet No.
1	107 of 114

☒ OC ☐ TMI

GPU Nuclear

Calibration Sheet

Cal Sheet# HR-034

System	Component	Procedure	Rev
187	Drywell Liner	6100-QAP-7209.07	0

	Signature	Print	Initial	ID#	Level
Examiner:	[signature]	J Vanderlinde	JV	154-43-0319	II
Examiner:	[signature]	Mark F. Bagnell	MFB	553-81-1802	I

Instrument Settings
ID# 137-113
Model/Manuf Sonic 137 / Staveley

Gain
Coarse 60.2
Fine N/A
Uncal N/A

Sweep Circuit
Coarse 20" (Up/0.201"/div) (Range)
Fine N/A
Delay 1.0
Screen Depth 2" (sync IP)

Operation (T&R) Normal
Frequency: 2.25 MHZ
Reject: ☐Off ☐On %
Filter: ☐Off ☐On 1 %
Damping: ☐Off ☐On 200 %
Rep Rate: 1000 Hz

Cal Standard
ID# 218
Size N/A Sch. N/A
Thickness .5 to 1.5"
S/S CS
Temp 68 °F

System Check
☐Exit Point
☐Angle +/- 2
N/A

Date 12-5-92

Search Unit
ID# M02524
Type MSEB
Freq 2 MHZ
Size 1/2"
Angle 0 Mode Long.

Cal Direction
☐Axial ☐Both
☐Circ. ☒Normal

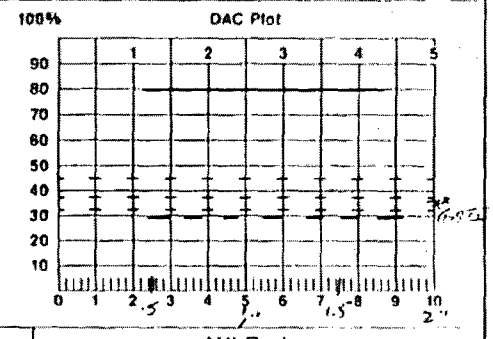
Time 0910

Search Unit Cable
Type 50 Ω dual line Length 216'

Couplant
Make Sound Safe Batch# SSP-32-1-02

Thermometer
S/N: 92-057 Cal Due 5-24-93

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	80	.5
.75	80	.75
1.0	80	1.0
1.25	80	1.25
1.5	80	1.5



Time/Date	0936 / 12-5-92		1020 / 12-5-92		1036 / 12-5-92	
Reflector inches	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	80	.5	80	.5	80	.5
.75	80		80		80	
1.0	80		80		80	
1.25	80		80		80	
1.5	80	1.5	80	1.5	80	1.5
Initials	JV		JV		JV	

Remarks:
* Reflection adjusted to 80% FSH as required
** Digital calibration independent of CRT
MIN .5"
MAX 1.5"

Components Examined:
Bay 17 & Bay 19

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 12-5-92

NDE Request#: 92-72

N0927 (05-90)

MOC TMI

GPU Nuclear

Calibration Sheet

Cal Sheet# 14A-045

System 187 | Component Drywell Liner | Procedure 5100-SAP-7202.02 | Rev 0

Examiner:	Signature:	Print: J. VanderLinde	Initial: JV	ID# 154-48-0519	Level II
Examiner:	Signature: Mark Bagnell	Print: Mark F. Bagnell	Initial: MB	ID# 553-81-1802	Level I

Instrument Settings
ID# 92-320
Model/Manuf DL 26 PANAMETRICS

Gain
Coarse N/A
Fine N/A
Uncal N/A

Sweep Circuit
Coarse N/A (Range)
Fine N/A
Delay N/A
Screen Depth N/A

Operation (T&R) Normal
Frequency: N/A MHZ
Reject: ☐Off ☐On N/A %
Filter: ☐Off ☐On N/A %
Damping: ☐Off ☐On N/A %

Rep Rate: N/A

Cal Standard
ID# 88
Size N/A Sch. N/A
Thickness .25 to 1.0"
S/S (CS)
Temp 72 °F

System Check
☐Exit Point
☐Angle +/- 2 N/A

Date 12/11/92

Search Unit
ID# 92-038
Type 0770 SIA
Freq 5 MHZ
Size 0.5"
Angle 0 Mode Long

Cal Direction
☐Axial ☐Both
☐Circ. ☒Normal

Time 1145

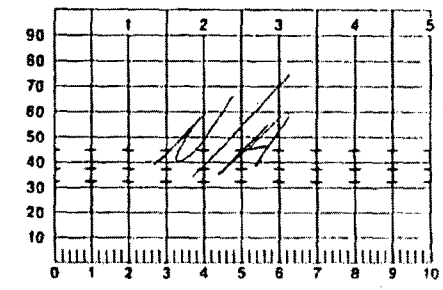
Search Unit Cable
Type SK contributed Length 2 x 6'

Couplant
Make Sound Safe Batch# SSP-27-1-02

Thermometer
S/N: 27-053 Cal Due 1-9-93

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	N/A	N/A
.75	N/A	N/A
1.0	N/A	N/A

DAC Plot



Time/Date	1225 / 12/11/92		1245 / 12/11/92		1315 / 12/11/92	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	N/A	.5	N/A	.5	N/A	.5
.75	N/A	.75	N/A	.75	N/A	.75
1.0	N/A	1.0	N/A	1.0	N/A	1.0
Initials	JV		JV		JV	

Remarks:

Components Examined:
CY 17 & 18

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 12-14-92

NDE Request#: 92-072

N0927 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	108 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

NOC TITMI

GPU Nuclear

Calibration Sheet

Cal Sheet# [illegible]

System	Component	Procedure	Rev
187	Drywell liner	6100-OAP-7209.07	0

Examiner:	Signature: [signature]	Print: J Vander Linde	Initial: [illegible]	ID# 157-48-038	Level II
Examiner:	Signature: n/a	Print: n/a	Initial: n/a	ID# n/a	Level n/a

Instrument Settings
ID# 92-010
Model/Manuf DL-26 PANAMETRICS

Gain
Coarse n/a
Fine n/a
Uncal n/a

Sweep Circuit
Coarse n/a (Range)
Fine n/a
Delay n/a
Screen Depth n/a

Operation
(T&R) Normal
Frequency: n/a MHZ
Reject: ☐Off ☐On n/a %
Filter: ☐Off ☐On n/a %
Damping: ☐Off ☐On n/a %

Rep Rate: n/a

Cal Standard
ID# 83
Size n/a Sch. n/a
Thickness .5 - 1.0
S/S (CS)
Temp 68 °F

System Check
☐Exit Point
☐Angle +/- 2° n/a

Search Unit
ID# 92-038
Type 2.25 SP
Freq 5 MHZ
Size 0.512
Angle 0 Mode Long.

Cal Direction
☐Axial ☐Both
☐Circ. ☒Normal

Date 12/14/92 Time 1305

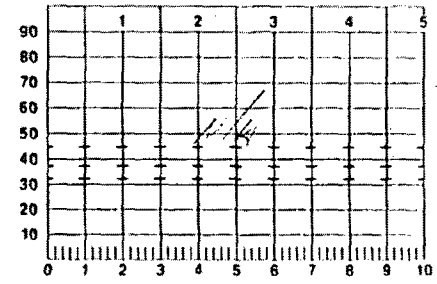
Search Unit Cable
Type 50Ω coaxial Length 2x5'

Couplant
Make Sonigel Batch# [illegible]

Thermometer [illegible] 12/14/92
S/N: ~~[illegible]~~ 92-057 Cal Due 5-24-93

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	n/a	n/a
.75	n/a	n/a
1.0	n/a	n/a

DAC Plot



Time/Date	1325 / 12/14/92		1337 / 12/14/92		1405 / 12/14/92	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	n/a	.5	n/a	.5	n/a	.5
.75	n/a	.75	n/a	.75	n/a	.75
1.0	n/a	1.0	n/a	1.0	n/a	1.0
Initials	[initials]		[initials]		[initials]	

Remarks:

Components Examined: BA 17019

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 12-16-92

NDE Request#: 92-072

N0927 (05-90)

GPU Nuclear

Subject	Calc No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	109 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli	
Date 01/12/93	**Rev. No.** 1	**Date**

NOC TMI

GPU Nuclear

Calibration Sheet

Cal Sheet# [illegible]

System	Component	Procedure	Rev
187	Drywell Liner	6100-OAP-7209.07	0

Examiner:	Signature: [signature]	Print: J. Van der Linde	Initial: [signature]	ID# 154 48-0319	Level II
Examiner:	Signature: N/A	Print: N/A	Initial: N/A	ID# N/A	Level N/A

Instrument Settings
ID# 137-113
Model/Manuf SONIC 137 STAVELY

Gain
Coarse 60.2
Fine N/A
Uncal N/A

Sweep Circuit
Coarse 2.0" (vel. 0.231"/μs) (Range)
Fine N/A
Delay 1.0
Screen Depth 2"

Operation
(T&P) Normal
Frequency: 2.25 MHZ
Reject: ☒Off ☐On ____ %
Filter: ☐Off ☒On 1 %
Damping: ☐Off ☒On 200 %

Rep Rate: 1000 Hz

Cal Standard
ID# 88
Size N/A Sch. N/A
Thickness .5 - 1.0
S/S (CS)
Temp 68 °F

System Check
☐Exit Point
☐Angle +/- 2 N/A

Date 12/14/92

Search Unit
ID# M08524
Type MSEB
Freq 2 MHZ
Size 1/2"
Angle 0 Mode Long

Cal Direction
☐Axial ☐Both
☐Circ. ☒Normal

Time 1300

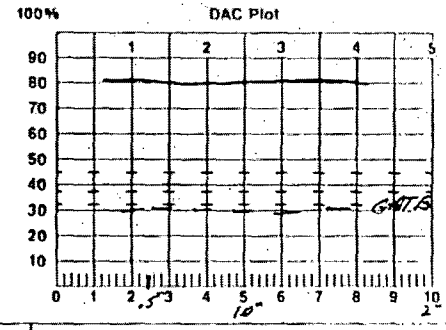
Search Unit Cable
Type dual lino Length 2x6'

Couplant
Make Sound Safe Batch# SSP 89-1-02

Thermometer
S/N: 92-057 Cal Due 5-24-93

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	80	.5
.75	80	.75
1.0	80	1.0

DAC Plot



Time/Date	1330 / 12/14/92		1335 / 12/14/92		1400 / 12/14/92	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	80	.5	80	.5	80	.5
.75	80	.75	80	.75	80	.75
1.0	80	1.0	80	1.0	80	1.0
Initials	[signature]		[signature]		[signature]	

Remarks:
* Backwall maintained at 80% FSH

Components Examined:
Bay 17019

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 12-16-92

NDE Request#: 92-072

N0927 (05-90)

GPU Nuclear

Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: N/A	Item: N/A	NDE Request: 92-072	Data Sheet No.: 92-072-11
Task Description: DRY WALL LINER MOCK-UP		Task No.: N/A	Date: 12-16-92
Comp. Desc.: WELD OVERLAY TEST PLATE	System: 187	Code/Spec.: ASME SECT VIII	
Procedure/Rev.: 6100-QAP-7209.07 / 0	Drawing No./Rev.: -NA-		
Test Surface: OD	Thickness: 3/4"	Material: C/S	
Examiner Sign: [signature]	Print: J. Van der Linde	ID No.: 154-46-0319	Level: II
Examiner Sign: [signature]	Print: JAMES PHILLIPPI	ID No.: 462277035	Level: I

Thermometer S/N 92-063 Part Temperature 68° F D-Meter S/N 92-010
Cal. Blk. S/N 214 Cal. In: N/A AM 1420 PM
Cal. Blk. Temp. 68° F Cal. Out: N/A AM 1440 PM

Calibration Readings (Inches)

Cal. Blk.	.502	.752	1.001	1.251		
D-Meter	.502	.751	1.000	1.250		

Techniques: ☐ CRT ☒ D-Meter
Other -NA-

Position #/Reading in Inches

Drawing

A-SCAN 26 DL

BASE METAL	.73	.728
1 PASS	.94	.927
2 PASS	1.12	1.114

Reviewed by: [signature] Level: III Date: 12-27-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject: O.C. Drywell Ext. UT Evaluation in Sandbed			
Originator: Mark Yekta	Date: 01/12/93	Calc No.: C-1302-187-5320-024	Rev. No.: 1
Reviewed by: S. C. Tummminelli	Date	Sheet No.: 111 of 114	

GPU Nuclear

Ultrasonic Thickness Data Sheet

☒ OC ☐ TMI-1 ☐ TMI-2	Class: n/a	Item: n/a	NDE Request: 92-072	Data Sheet No.: 92-072-11
Task Description: DRY WALL LINER MOCK-UP		Task No.: n/a		Date: 12-16-92
Comp. Desc.: WELD OVERLAY TEST PLATE	System: 187		Code/Spec.: ASME SECT VIII	
Procedure/Rev.: 6100-QAP-7209.07 / 0		Drawing No./Rev.: -NA-		
Test Surface: OD		Thickness: 3/4"	Material: C/S	
Examiner	Sign:	Print: J. Van der Linde	ID No.: 154-48-0319	Level: II
Examiner	Sign:	Print: JAMES PHILLIPPI	ID No.: 462277035	Level: I

Thermometer S/N 92-063 Part Temperature 68° F D-Meter S/N 92-010
Cal. Blk. S/N 214 Cal. In: N/A AM 1420 PM
Cal. Blk. Temp. 68° F Cal. Out: N/A AM 1440 PM

Calibration Readings (Inches)

Cal. Blk.	.502	.752	1.001	1.251		
D-Meter	.502	.751	1.000	1.250		

Techniques: ☐ CRT ☒ D-Meter
Other -NA-

Position #/Reading In Inches

Drawing

	A-SCAN	26 DL
BASE METAL	.73	.728
1 PASS	.94	.927
2 PASS	1.12	1.114

Reviewed by: [signature] Level: III Date: 12-27-92 Page 1 of 1

N5455 (05-90)

GPU Nuclear

Subject	Originator	Date	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	Mark Yekta	01/12/93	C-1302-187-5320-024	1	113 of 114
			Reviewed by S. C. Tumminelli		Date

GPU Nuclear

LOC TMI

Calibration Sheet

Cal Sheet# 142-052

System: 187 | Component: DRYWELL LINER | Procedure: 6100-QAP-7209.07 | Rev. 0

Examiner: Signature: [signature] | Print: J VanderLinde | Initial: JV | ID# 154-48-039 | Level II

Examiner: Signature: [signature] | Print: JAMES PHILLIPPI | Initial: JP | ID# 462277035 | Level I

Instrument Settings
ID# 137-113
Model/Manuf SONIC 137 / STAVELEY

Gain
Coarse 60.2 dB
Fine N/A
Uncal N/A

Sweep Circuit
Coarse 2.0" (VEL. = .231 "/μs) (Range)
Fine N/A
Delay 1.0
Screen Depth 2"

Operation
T&R Normal
Frequency: 2.25 MHZ
Reject: ☒Off ☐On N/A %
Filter: ☐Off ☒On FILT 1 %
Damping: ☐Off ☒On 200Ω %

Rep Rate:

Cal Standard
ID# 214
Size NA Sch. NA
Thickness .5 → 1.25
S/S (CS) NA
Temp 68 °F

System Check N/A
☐Exit Point A
☐Angle +/- 2

Search Unit
ID# M08524
Type MSEB
Freq 2.0 MHZ
Size .5"
Angle 0 Mode LONG

Cal Direction
☐Axial ☐Both
☐Circ. ☒Normal

Date 12-16-92 | Time 1410

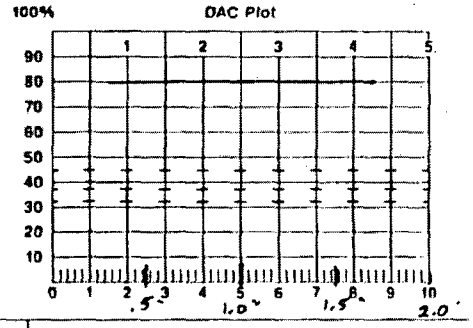
Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	80	.5
.75	80	.75
1.0	80	1.0
1.25	80	1.25

Search Unit Cable
Type DUAL LIMO Length 2 x 6'

Couplant
Make SOUNDSAFE Batch# SSP-89-1-02

Thermometer
S/N: 92-063 Cal Due 5-24-93

DAC Plot



Time/Date	1415 / 12-16-92		1425 / 12-16-92		/	
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	80	.5	80	.5		
.75	80	.75	80	.75		
1.0	80	1.0	80	1.0		
1.25	80	1.25	80	1.25		
Initials	[initials]		[initials]			

Remarks:

Components Examined: Drywell liner weld overlay
Test data

ANI Review

Technical Review
Reviewed By [signature]
Level III Date 12-27-92

NDE Request#: 92-072

N0927 (05-90)

Examiner:	Signature: James Phillippi	Print: JAMES PHILLIPPI	Initial: JP	ID# 462277035	Level I

Instrument Settings
ID# 92-010
Model/Manuf DL-26 PANAMETRICS

Gain
Coarse N/A
Fine N/A
Uncal N/A

Sweep Circuit
Coarse N/A (Range)
Fine N/A
Delay N/A
Screen Depth N/A

Operation
T&R Normal
Frequency: N/A MHZ
Reject: ☐Off ☐On N/A %
Filter: ☐Off ☐On N/A %
Damping: ☐Off ☐On N/A %

Rep Rate: N/A

Cal Standard
ID# 214
Size N/A Sch. N/A
Thickness .5 → 1.5
S/S (CS) N/A
Temp 68 °F

System Check N
☐Exit Point A
☐Angle +/- 2

Search Unit
ID# 92-038
Type D790 SM
Freq 5 MHZ
Size .312
Angle 0 Mode LONG.

Cal Direction
☐Axial ☐Both
☐Circ. ☒Normal

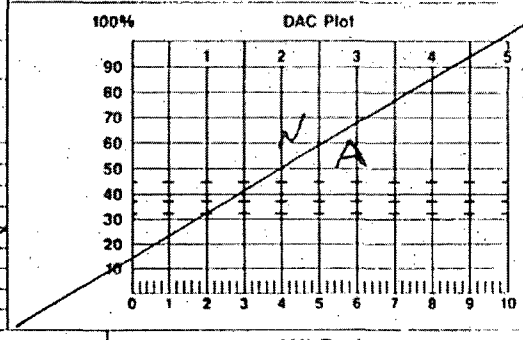
Date 12-16-92 Time 1412

Reflector	Amplitude % of FSH	Screen Reading in Inches
.5	N/A	N/A
.75	N/A	N/A
1.0	N/A	N/A
1.25	N/A	N/A

Search Unit Cable
Type SELF CONTAINED Length 2 x 6'

Couplant
Make SOUNDSAFE Batch# SSD-89-1-02

Thermometer
S/N: 92-063 Cal Due 5-24-93



Time/Date	1420 12-16-92		1440 12-16-92			
Reflector	% FSH	Inches	% FSH	Inches	% FSH	Inches
.5	N/A	.5	N/A	.5		
.75	N/A	.75	N/A	.75		
1.0	N/A	1.0	N/A	1.0		
1.25	N/A	1.25	N/A	1.25		
Initials						

Remarks:

Components Examined:
Drywell liner weld overlay
Test plate

ANI Review

Technical Review
Reviewed By
Level II Date 12-27-92

NDE Request#: 92-072

N0927 (05-90)

GPU Nuclear

Subject	Calc No.	Rev. No.	Sheet No.
O.C. Drywell Ext. UT Evaluation in Sandbed	C-1302-187-5320-024	1	114 of 114
Originator Mark Yekta	**Reviewed by** S. C. Tumminelli		
Date 01/12/93			**Date**

ATTACHMENT 1
Design Analysis Cover Sheet 1

Design Analysis (Major Revision)		**Last Page No.** [6] A5 of 15	
Analysis No.: [1]	C-1302-243-5320-071	**Revision:** [2]	2
Title: [3]	Drywell Thickness Margins		
EC/ECR No.: [4]	06-00634	**Revision:** [5]	0

		Component(s): [14]	
Station(s): [7]	Oyster Creek		
Unit No.: [8]	1	187	
Discipline: [9]	Mechanical		
Descrip. Code/Keyword: [10]	WALL THICKNESS		
Safety/QA Class: [11]	Q		
System Code: [12]	187		
Structure: [13]	Drywell		

CONTROLLED DOCUMENT REFERENCES [15]

Document No.:	From/To	Document No.:	From/To
GE Report Index 9-3.	From		
GE Report Index 9-4	From		
C-1302-187-~~5300-025~~ 8610-030 24	From		
C-1302-187-5320-024	To		0

Is this Design Analysis Safeguards Information? [16] **Yes** ☐ **No** ☒ If yes, see SY-AA-101-106

Does this Design Analysis contain Unverified Assumptions? [17] **Yes** ☐ **No** ☒ If yes, ATI/AR#:

This Design Analysis SUPERCEDES: [18] **N/A** **in its entirety.**

Description of Revision (list affected pages for partials): [19]

See the Summary of Change Sheet, which is attached. (PG. 1a)

Preparer: [20]	Peter Tamburro (Print Name)	(Sign Name)	8/22/06 (Date)

Method of Review: [21] **Detailed Review** ☒ **Alternate Calculations (attached)** ☐ **Testing** ☐

Reviewer: [22]	Thomas Ruggiero (Print Name)	(Sign Name)	9/13/06 (Date)

Review Notes: [23] Independent review ☒ Peer review ☐

The calc revision has been independently reviewed IAW procedures CC-AA-309 & CC-AA-309-1001 and deemed to be acceptable.

(For External Analyses Only)

External Approver: [24]	– (Print Name)	(Sign Name)	(Date)
Exelon Reviewer: [25]	– (Print Name)	(Sign Name)	(Date)

Is a Supplemental Review Required? [26] **Yes** ☐ **No** ☒ If yes, complete Attachment 3

Exelon Approver: [27]	T. NICKERSON * (Print Name)	(Sign Name)	9/21/06 (Date)

* ACTING MANAGER FOR F.H. RAY (WITH HIS CONCURRENCE).

168532

GPU Nuclear

DOCUMENT NO. C-1302-243-5320-071

TITLE Drywell Thickness Margins

PAGE 1a

REV	SUMMARY OF CHANGE	APPROVAL	DATE
1	Added Pages A1 through A5 to address new local thicknesses in the Drywell Shell for the New Design Pressure of 44 psig and New Design Temperature of 292°F	A. H. / J. H. Hartro	4-19-95 / 4/19/95
2	Revised Pages A3 of 15 and A5 of 15. Revision 1 of this Calculation does not state whether the Sandbed Local Wall thickness criteria Developed on those pages applies to PT Buckling Loads. Revision 2 of clarifies that this criteria does not apply to Buckling and refers to C-1302-187-5320-024 Revision 1 for the evaluation of Local Buckling, AS PART OF ECR # 06-00634. Also deleted Reference 3 which was superceded by C-1302-187-8610-030.	P. Tamburro / [illegible]	8/22/06
		T. Ruggiero / [illegible]	9/13/06
		[illegible] T. NICKERSON ACTING FOR F.H. RAY	9/21/06

N0036 (03-90)

170223

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	0	1b of 15

Originator	Date	Reviewed by	Date
V. YERTA	11/93		2/14/94

A Hearn 6-1-94
J. H. Barton 9/14/94

1.0 PROBLEM STATEMENT:

THE OYSTER CREEK TECHNICAL SPECIFICATION CHANGE REQUEST FOR THE DRYWELL DESIGN PRESSURE FROM 62 PSIG TO 44 PSIG AND DESIGN TEMPERATURE FROM 175°F TO 292°F HAS BEEN APPROVED BY THE NRC. THIS CALCULATION COMPUTES THE MINIMUM DRYWELL THICKNESS REQUIREMENTS FOR THE NEW DESIGN PRESSURE OF 44 PSIG FOR THE LIMITING CASE I - INITIAL TEST CONDITION:

DEADWEIGHT + 44 PSIG DESIGN PRESSURE

+ SEISMIC (2 X DBE) $\leq$ 19,300 PSI

BASED ON THE DESIGN INFORMATION THAT IS DOCUMENTED IN GE'S REFERENCE 1 CALCULATION.

THE MINIMUM THICKNESS REQUIREMENT FOR THE SANDBED REGION OF THE DRYWELL IS SEPARATELY CONTROLLED BY BUCKLING FOR THE LIMITING CASE IV - REFLOODING CONDITION BASED ON THE DESIGN INFORMATION IN GE'S REFERENCE 2 CALCULATION.

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-07	0	2 of 15
Originator: M YEKTA, Date: 11/93	Reviewed by		Date: 2/14/94

2.0 SUMMARY OF RESULTS:

THE MINIMUM REQUIRED THICKNESSES TABULATED IN TABLE 1 FOR THE CYLINDRICAL UPPER AND MIDDLE, AND THE SANDBED REGIONS OF THE DRYWELL ARE LESS THAN THE MINIMUM AS-FOUND THICKNESSES TABULATED IN REFERENCE 3.

THE MINIMUM REQUIRED THICKNESS TABULATED IN TABLE 1 FOR THE LOWER SPHERICAL REGION OF THE DRYWELL IS LESS THAN THE MINIMUM AS-FOUND THICKNESS TABULATED IN REFERENCE 4

TABLE 1 WAS DISTRIBUTED TO ENGINEERING PROJECTS AS AN ATTACHMENT TO THE REFERENCE 5 MEMORANDUM.

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	~~0~~ 2	3 of 15

Originator	Date	Reviewed by	Date
M. YERTA	11/93		2/14/94

3.0 REFERENCES:

1. GE CALCULATION "AN ASME SECTION VIII EVALUATION OF OYSTER CREEK DRYWELL FOR WITHOUT SAND CASE / PART I / STRESS ANALYSIS" DATED 2/91, DRF # 00664, INDEX NO. 9-3, REV. 0.

2. GE CALCULATION "AN ASME SECTION VIII EVALUATION OF THE OYSTER CREEK DRYWELL FOR WITHOUT SAND CASE / PART 2 / STABILITY ANALYSIS / (REVISION 2)" DATED 11/92, DRF # 00664, INDEX 9-4, REV. 2.

3. ~~GPU CALCULATION NO. C-1302-187-5300-025, "STATISTICAL ANALYSIS OF DRYWELL THICKNESS DATA THRU DECEMBER 1992," DATED 3/9/93, REV. 0.~~ R.2

4. GPU DRAWING NO. 3E-187-29-001 "DRYWELL PRESSURE VESSEL UT TEST LOCATIONS," REV. 0, DATED 1/16/92

5. GPUN MEMO NO. 5320-94-130, DATED 9/15/94

Replace.

GPU Calculation C-1302-187-8610-030 Rev. 1 "Statistical Analysis of Drywell Thickness Data thru September 1996" R2

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	0	4 of 15
Originator: M. YSKTA, Date: 11/93	Reviewed by		Date: 2/14/94

4.0 ASSUMPTIONS AND BASIC DATA:

THE DATA USED IN THIS CALCULATION IS DOCUMENTED IN REFERENCES 1-4.

THIS CALCULATION CONTAINS NO UNVERIFIED ASSUMPTIONS.

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS ~~D.C DRYWELL GE REPORT 9.3 UPGRADE~~	C-1302-243-5320-071	0	5 of 15
Originator M. Yekta — **Date** 11/93	**Reviewed by**		**Date** 2/14/94

5.0 CALCULATION:

CYLINDRICAL REGION:

New Design Pressure = 44 psig

Original Design Thickness = 0.640"

Original Design Pressure = 62 psig

Max. calculated primary Membrane Stress = 19,200 psi (Ref. 1)

Allowable Primary stress = 19,300 psi (Ref 1)

As Measured Thickness = 0.619"

Inside Cylindrical Radius = 198"

New calculated Primary Membrane Stress;

$$\sigma_{Design}^{*} = \frac{(44\,psi)(198.32")}{0.640"} = 13,600\ psi < 19,300\ psi$$

$$\sigma_{As\,found} = \frac{(44)(198.3095)}{0.619"} = 14,100\ psi < 19,300\ psi$$

New Required Thickness;

$$t = \frac{Pr}{\sigma_{all}} = \frac{(44)(198.3095)}{19,300} = \underline{\underline{0.452"}}$$

* $\sigma_{D.W.+S.E}$ IS NEGLIGIBLE IN THIS REGION.

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS		C-1302-243-5320-071	0	6 of 15
Originator	**Date**	**Reviewed by**		**Date**
M. YERETA	11/93			2/14/94

CALCULATION:

UPPER SPHERE:

Original Design Pressure = 62 psig

New Design Pressure = 44 psig

Original Design Thickness = 0.722"

As Measured Thickness = 0.677"

Max. Calculated Primary Membrane Stress = 19,090 psi (Ref. 1

Allowable primary Membrane Stress = 19,300 psi (Ref. 1

Inside Spherical Radius = 420"

New Calculated Primary Membrane Stress;

$$\sigma_{TOTAL} = \sigma_{Press_{(62)}} + \sigma_{D.W+S.E}$$

$$19090 = \frac{(62)(420.361)}{(2)(0.722)} + \sigma_{D.W+S.E}$$

$$\sigma_{D.W+S.E} = 19090 - 18049 = 1041 \text{ psi}$$

$$\sigma_{TOTAL\ New} = \sigma_{D.W+S.E} + \sigma_{Press\ (44)}$$

$$\sigma_{TOTAL\ New} = 1041 + \frac{(44)(420.361)}{(2)(0.722)} = 13,850 < 19,300$$

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-07	0	7 of 15

Originator	Date	Reviewed by	Date
M. YBETA	11/93		2/14/94

CALCULATION:

UPPER SPHERE (Continued):

$$\sigma_{TOTAL\ As\ found} = (1041)\left(\frac{0.722}{0.677}\right) + (12{,}809)\left(\frac{0.722}{0.677}\right) =$$

$$\sigma_{TOTAL\ As\ found} = 14{,}800\ psi$$

New Required Thickness:

$$\sigma_{Allow} = (\sigma_{DW} + \sigma_{S.B})\left(\frac{0.722''}{t}\right) + (\sigma_{Press})\left(\frac{0.722}{t}\right)$$

~~Assume~~ $\therefore t = \cancel{0.520''}$ 0.518

$$\cancel{19{,}300 = (1041)\left(\frac{0.722}{0.520}\right) + (12{,}809)\left(\frac{0.722}{0.520}\right)}$$

~~19,300 = 19,230 ∴ Therefore~~ $\cancel{t_{req} = 0.520''}$

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	0	8 of 15

Originator	Date	Reviewed by	Date
M. YEKTA	11.93		2/14/94

CALCULATION:

MIDDLE SPHERE:

Original Design Pressure = 62 psig

New Design Pressure = 44 psig

Original Design Thickness = 0.770"

As Measured Thickness = 0.723"

Max. Calculated Primary Membrane Stress = 18,460 psi

Allowable Primary Membrane Stress = 19,300 psi

Inside Spherical Radius = 420"

New Calculated Primary Membrane Stress:

$$\sigma_{TOTAL} = \sigma_{P_{62}} + \sigma_{D.W+S.E}$$

$$18,460 = \frac{(62)(420.385)}{(2)(0.77)} + \sigma_{D.W+S.E}$$

$$\sigma_{D.W+S.E} = 18,460 - 16,925 = 1535 \text{ psi}$$

$$\sigma_{TOTAL_{New}} = \sigma_{P_{44}} + \sigma_{D.W+S.E}$$

$$\sigma_{TOTAL} = \frac{(44)(420.385)}{(2)(0.770)} + 1535 = 13,550 \text{ psi} < 19,300 \text{ psi}$$

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS		C-1302-243-5320-071	0	9 of 15
Originator M. YEKTA	Date 11/93	Reviewed by		Date 2/14/94

CALCULATION:

MIDDLE SPHERE (Continued):

$$\sigma_{TOTAL\ As\ found} = (1535)\left(\frac{0.770}{0.723}\right) + 12{,}011\left(\frac{0.770}{0.723}\right) = 14{,}450\ psi < 19{,}300$$

New Require Thickness;

$$\sigma_{Allowable} = (\sigma_{D.W+S.E})\left(\frac{0.770}{t}\right) + \sigma_{Press}\left(\frac{0.770}{t}\right)$$

~~Assume~~ $\therefore t = \cancel{0.550}$ 0.541"

$$\cancel{19{,}300 = (1535)\left(\frac{0.770}{0.550}\right) + (12{,}011)\left(\frac{0.770}{0.550}\right)}$$

~~19,300 = 19,000 ∴ Therefore~~ $\cancel{t_{req} = \underline{\underline{0.550"}}}$

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS		C-1302-243-5320-071	0	10 of 15
Originator M. YEXTA	Date 11/93	Reviewed by		Date 2/14/94

CALCULATION:

LOWER SPHERE USING SMALL DISPLACEMENT

Original Design Pressure = 62 psig

New Design Pressure = 44 psig

Original Design Thickness = 1.154"

As Measured Thickness = 1.154"

Max Calculated Primary Membrane Stress: 13,800 psi

Allowable Primary Membrane Stress: 19,300 psi

Inside Spherical Radius = 420"

Primary Membrane Stress for New Design Pressure:

$$\sigma_{TOTAL} = \sigma_{\substack{press \\ 62}} + \sigma_{D.W+S.E}$$

$$13,800 = \frac{(62 \times 420.577)}{(2)(1.154)} + \sigma_{DW+SE}$$

$$\therefore \sigma_{D.W+S.E} = 13,800 - 11,298 = 2502 \text{ psi}$$

$$\sigma_{\substack{TOTAL \\ P=44}} = \frac{(44)(420.577)}{(2)(1.154)} + 2502 \simeq 10,520 \text{ psi} < 19,300 \text{ psi}$$

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS		C-1302-243-5320-071	0	11 of 15
Originator M. YEKTA	**Date** 11/93	**Reviewed by**		**Date** 2/14/94

CALCULATION:

LOWER SPHERE USING SMALL DISPLACEMENT

New Require Thickness;

$$\sigma_{ALLOWABLE} = (\sigma_{D.W+S.E})\left(\frac{1.154}{t}\right) + \sigma_{PMS\,44}\left(\frac{1.154}{t}\right)$$

ASSUME $t = 0.650''$

$$\cancel{19300 = (2502)\left(\frac{1.154}{0.650}\right) + (8018)\left(\frac{1.154}{0.650}\right)}$$

$$\cancel{19300 \simeq 18,700 \text{ psi}}$$

$\therefore$ Therefore $t_{req} = \cancel{0.650''}$ 0.629"

This region no longer requires a large displacement analysis PER REF. 1.

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	0	12 of 15

Originator	Date	Reviewed by	Date
M. YESTA	11/93		2/14/94

CALCULATION

SANDBED REGION USING SMALL DISPLACEMENT:

Original Design Pressure = 62 psig

New Design Pressure = 44 psig

Original Design Thickness = 1.154"

As Measured Thickness = 0.736"

Allowable Primary Membrane Stress = 19,300 psi

Max Calculated Local Primary Membrane Stress = 22,970 psi

Primary Membrane Stress for New Design Pressure:

$$\sigma_{TOTAL} = \sigma_{\substack{Press \\ 62}} + \sigma_{D.W+S.E}$$

$$22,970 = \frac{(62)(420.368)}{(2)(0.736)} + \sigma_{DW+S.E}$$

$$\therefore \sigma_{DW+S.E} = 22,970 - 17,706 = 5264 \text{ psi}$$

REF 5 1,7

$$\sigma_{\substack{TOTAL \\ P=44}} = \frac{(44)(420.368)}{(2)(0.736)} + 5264 = 17,830 \text{ psi} < 19,300$$

∴ This region no longer requires a large displacement analysis and the thickness requirement for this region will still remain as t=0.736" because of buckling

N 0016 (10

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	0	13 of 15

Originator	Date	Reviewed by	Date
M. YERTA	11/93		2/14/94

THIS LAST SECTION OF THE CALCULATION COMPUTES THE MINIMUM REQUIRED THICKNESS FOR THE PREVIOUS DESIGN PRESSURE OF 62 PSIG:

1. CYLINDER:

$$t = \frac{62 \times 198.3}{19,300}$$

$$t = 0.637''$$

2. UPPER SPHERE: *

$$t = 0.722 \times \frac{19,090}{19,300}$$

$$t = 0.714''$$

3. MIDDLE SPHERE:

$$t = 0.770 \times \frac{18,460}{19,300}$$

$$t = 0.736''$$

* MEMBRANE STRESSES INVERSELY PROPORTIONAL TO THICKNESSES.

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS		C-1302-243-5320-071	0	14 of 15
Originator M. YEKTA	Date 11/93	Reviewed by		Date 2/15/94

4. LOWER SPHERE:

$$t = 1.154 \times \frac{13,800}{19,300}$$

$$t = 0.825''$$

5. SANDBED:

$t = 0.736''$, GOVERNED BY BUCKLING

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
DRYWELL THICKNESS MARGINS	C-1302-243-5320-071	0	15 of 15

Originator	Date	Reviewed by	Date
M. YEKTA	11/93		2/14/94

TABLE 1.

DRYWELL REGION	AS DESIGNED THICKNESS (INCHES)	DESIGN PRESSURE 62 PSIG T REQ (INCHES	NEW DESIGN PRESSURE 44 PSIG T REQ (INCHES)	LATEST (12/92) AS FOUND THICKNESS T MEASURED (INCHES
CYLINDRICAL	0.640	0.637	0.452	0.614
UPPER SPHERE	0.722	0.714	0.518	0.691
MIDDLE SPHERE	0.770	0.736	0.541	0.743
LOWER SPHERE	1.154	0.825	0.629	0.803 (2)
SANDBED	1.154	0.736 (1)	0.736 (1)	0.800

NOTES:

1. CONTROLLED BY BUCKLING (REF. 2)

2. AS-FOUND T FROM REF. 4

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
Drywell Thickness Margins		C-1302-243-6320-071	1	A1 of 15
Originator	Date	Reviewed by		Date
J. H. Horton	4/18/95	[illegible]		4-19-95

Appendix A

Calculation of New Local Thicknesses for the Drywell using the new Design Pressure and Temperature

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
Drywell Thickness Margins	C-1302-243-5520-071	1	A2 of 15

Originator	Date	Reviewed by	Date
J. H. Horton	4/18/95	A. Hwang	4-19-95

Appendix A

1.0 Statement of Problem

Determine the Local thickness Reductions due to the Change in Drywell Design Pressure and Temperature.

2.0 Summary of Results

The Minimum Required Local thicknesses are based on 2/3 of thicknesses Calculated in the main Body of this Calculation. This 2/3 ratio is based of the Difference of 1.0 Smc ~~for~~ allowable for the Minimum Required general thickness and 1.5 Smc ~~for~~ allowable for the Local thicknesses (ie 1.0 Smc/1.5 Smc = 2/3). This approach is acceptable provided the Local area does not exceed 2 inches in diameter. Because of this Limitation there is no effect on the seismic Loads in the area where this Local reduction in thickness occures. These Local thicknesses are shown on the Following Table.

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
Drywell Thickness Margins	C-1302-248-5320-071	1 → 2	A3 of 15
Originator: J. H. Horton, Date: 4/18/95	Reviewed by: A. Huang		Date: 4-19-95

Appendix A

2.0 Summary of Results (Con't)

Drywell Region	As Designed Thickness (inches)	New Design Pressure 44 Psig required thickness Table 1 Pg 15 this calc. (inches)	New Local Required thickness for 44 Psig (inches)
Cylindrical	0.640	0.462	0.301
Upper Sphere	0.722	0.518	0.345
Middle Sphere	0.770	0.541	0.360
Lower Sphere	1.154	0.629	0.419
Sandbed	1.164	0.736 (1)	~~0.440~~ 0.480 (2)

NOTES:

(1) Controlled by buckling (Ref. #2)

(2) Value is for primary stresses only. Evaluation of Local Regions in Sandbed are Contained in C-1302-187-5320-024 Rev 1.

A.2

GPU Nuclear

Calculation Sheet

Subject		Calc No.	Rev. No.	Sheet No.
Drywell Thickness Margins		C-1302-243-5320-011	1	A4 of 15
Originator	Date	Reviewed by		Date
J. Horton	4/18/95	A. Huang		4-19-95

3.0) References

Same as the Revision 0 of this Calculation

4.0) Assumptions

4.1 Local Areas shall not exceed 2" in Diameter and as such will not have any effect on the structures capability to sustain the Seismic Loads addressed in Pages 1 thru 15 of this Calculation.

4.2 These Calculations will only consider the code requirement for Local Primary Stress and as such only require the thicknesses to be ratioed by 1/3 to account for the change in allowable from 1.0 Smc to 1.5 Smc.

5.0) Calculations

5.1 Calculation of Cylindrical Region Local Thickne.

$$t_c = \frac{1.0\ Smc}{1.5\ Smc}(t) = \frac{1.0}{1.5}(.452) = 0.301$$

GPU Nuclear

Calculation Sheet

Subject	Calc No.	Rev. No.	Sheet No.
Drywell Thickness Margins	C-1302-283-5320-019	2	A5 of 15
Originator: J. H. Horton, Date: 4/18/95	Reviewed by: [illegible]		Date: 4-19-95

5.0) Calculation (Con't)

5.2 Calculation of Upper Sphere Region Local Thickness

$$t_{US} = \frac{1.0\ S_{mc}}{1.5\ S_{mc}}(t_r) = \frac{1.0}{1.5}(0.518) = 0.345''$$

5.3 Calculation of Middle Sphere Region Local Thickness

$$t_{MS} = \frac{1.0\ S_{mc}}{1.5\ S_{mc}}(t_r) = \frac{1.0}{1.5}(0.541) = 0.361''$$

5.4 Calculation of Lower Sphere Region Local Thickness

$$t_{LS} = \frac{1.0\ S_{mc}}{1.5\ S_{mc}}(t_r) = \frac{1.0}{1.5}(0.629'') = 0.419''$$

5.5 Calculation of Sandbed Region Local Thickness

~~$t_{SB} = \frac{1.0\ S_{mc}}{1.5\ S_{mc}}(t_r) = \frac{1.0}{1.5}(0.736) = 0.491''$~~

Refer to Calculation C-1302-187-5320-024 Revision 1. R-2

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee

Docket Number: (not applicable)

Location: Rockville, Maryland

Date: Tuesday, October 3, 2006

Work Order No.: NRC-1271 Pages 1-232

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(202) 234-4433

1 MR. GALLAGHER: Precoating, Pete?

2 MR. TAMBURNO: We do have a few pictures

3 of the vessel after cleaning of the corrosion

4 byproducts but before coating.

5 MEMBER ARMIJO: Okay, so there's some.

6 MR. GALLAGHER: So the embed area is what

7 we're talking about now. As I said --

8 MEMBER WALLACE: This is what you used to

9 convince the NRC that using some sort of average was

10 okay and that the pock marks weren't too deep and all

11 that kind of stuff? These photographs are what you

12 used?

13 MR. GALLAGHER: Well, there was some data

14 from the outside, Pete, the exploratory data from the

15 outside?

16 MR. TAMBURNO: We took the inspection --

17 after we removed the corrosion byproducts, we

18 performed a visual inspection of 100 percent of the

19 sandbed region and then we inspected through UT

20 measurements, the thinnest we found. We then

21 evaluated those thinnest areas in a calculation and

22 compared them to the results of the GE analysis.

23 MR. GALLAGHER: So the embed, the drywell

24 shell at the juncture of the concrete floor was sealed

25 with a silicone to prevent water intrusion going

1 forward into the embedded drywell shell. The
2 potential for corrosion of the inaccessible embedded
3 shell prior to this corrective action has also been
4 assessed. The water that was in the sandbed region is
5 not aggressive to concrete. Therefore, our assessment
6 is that the corrosion of the inaccessible embed shell
7 is not significant, since it is protected by the high
8 alkalinity in concrete.
9 MEMBER WALLACE: Well, it was corrosive to
10 steel. So once it got in there, it's going to eat its
11 way in further, isn't it?
12 MR. GALLAGHER: Ahmed.
13 MR. OUAOU: The embedded shell is
14 protected by the alkaline environment in concrete and
15 that --
16 MEMBER WALLACE: And that counteracts the
17 corrosive activities of the water?
18 MR. OUAOU: That does not counteract the
19 corrosivity of water. The water was not corrosive.
20 In order for water to be --
21 MEMBER WALLACE: I think it was corrosive
22 because the shell corroded.
23 MR. GALLAGHER: Yeah, we're talking about
24 the area at the concrete interface and below.
25 MEMBER WALLACE: It's the bottom of --

1 MR. GALLAGHER: Yeah, and -- yeah, but --
2 MEMBER WALLACE: Explain why this
3 corrosion couldn't go any further.
4 MR. GALLAGHER: Right, where it was
5 corroded was above that area where the wet sand was in
6 contact with --
7 MEMBER WALLACE: You're convincing us it
8 didn't go any further.
9 MR. GALLAGHER: That's correct, not
10 significantly.
11 MEMBER WALLACE: You're convincing us not
12 significantly or no?
13 MR. GALLAGHER: No.
14 MEMBER WALLACE: It doesn't go --
15 MR. GALLAGHER: That the corrosion would
16 not be significant.
17 MEMBER WALLACE: Verbal arguments or
18 something else?
19 MR. GALLAGHER: This is consistent with
20 the GALL of embedded --
21 MEMBER WALLACE: GALL says it doesn't
22 corrode?
23 MR. GALLAGHER: Embedded seal in concrete.
24 If you meet certain criteria of the water not being
25 aggressive to the concrete, it does.

1 CHAIRMAN MAYNARD: Okay.

2 MR. TAMBURNO: Can I just to make a

3 comment, certainly the embedded portion -- do you have

4 the slide with the embedded shell, John, please?

5 MR. GALLAGHER: We have a cross-section of

6 that area, showing the embed and a skirt, the drywell

7 skirt that's below it.

8 MR. TAMBURNO: What this slide shows is

9 the sandbed, the area where we applied seal after 1992

10 and that shows, you know, the portion of the shell

11 that's embedded in the concrete and then you have a

12 skirt which is a support for the shell under

13 construction. Certainly, we really can't say that

14 there's no corrosion in the embedded shell. There

15 could be corrosion. What we maintain is that the

16 corrosion should be less than in the sandbed region

17 because of the protection that the alkaline

18 environment provides for the steel.

19 But in the case of the embedded shell, if

20 you look at the elevation 8 foot 3 and the bottom of

21 the sandbed is 8 foot 11, the corrosion should be

22 limited to that area, and of course, the skirt could

23 have some corrosion, but the skirt is not relied upon

24 as a support after the concrete was poured.

25 MEMBER SIEBER: So this skirt goes 360

1 degrees around solid, so moisture would have to drill
2 through that skirt to go under --
3 MR. GALLAGHER: That's one of the points
4 we were trying to make is that the skirt does provide
5 a barrier and if you look at the plate thicknesses,
6 the plate thickness above, you know, where the skirt
7 is and in sandbed regions is the 1.159 and then below
8 that is where -- it's the thinner skirt, so we think
9 that the -- because of, you know, the concrete as we
10 described, that the corrosion in that area would be
11 less significant than the corrosion that was
12 experienced in the sandbed region and then we did the
13 analysis assuming that plate was at a uniform
14 thickness of .736. So we feel that's covered.
15 MEMBER ARMIJO: Just one thing; when you
16 inspected that area right down where, you know, if you
17 could install a seal, the silicone seal, you must have
18 looked at it and was the corrosion worse or equivalent
19 in that region right close to the concrete or was it
20 less?
21 MR. GALLAGHER: Yes, Pete can answer that
22 question.
23 MR. TAMBURNO: We did inspect that area
24 during the repair activities in there and the
25 corrosion in that area was no worse than -- than the

worst areas above it.

MEMBER WALLACE: That doesn't say very much.

MR. TAMBURNO: So it was no better.

MEMBER WALLACE: It was no better, right?

MR. GALLAGHER: Yeah, so it was the same. But there you would expect it to be similar because the sand, the wet sand -- there was sand throughout so the sand was contacting that. What we're saying is below that interface, it would be less -- the corrosion should be less significant because of the concrete that's embedded in it.

MEMBER ARMIJO: And that's a debate, right? That's an ongoing debate.

MR. GALLAGHER: Well, we think we're consistent with the guidance that's in the GALL and --

MEMBER WALLACE: You replaced the seal, did you?

MR. GALLAGHER: We put that seal in.

MEMBER WALLACE: You put it in afterwards.

MR. GALLAGHER: Yes, this is the corrective action.

MEMBER WALLACE: Okay.

CHAIRMAN MAYNARD: I'd like to move on with the presentation.

1 MR. GALLAGHER: Yes, sir.

2 MEMBER SIEBER: I'd like to ask, beyond,
3 in our package the last slide you have is Slide 28.
4 You're referring to backup slides which should be made
5 part of the record. So -- okay.

6 MR. GALLAGHER: Yeah, any slide we show,
7 we'll put in.

8 MEMBER SIEBER: Okay, we'll I'd like to
9 have copies of this.

10 CHAIRMAN MAYNARD: Yeah, I want to remind
11 everybody, we still have the staff's presentation
12 after this and we also have public comment time. I
13 want to make sure we get a chance to get through this
14 and we'll see where we need to come back to.

15 MEMBER WALLACE: I'm sorry, Mr. Chairman,
16 I'm responsible for this. I want to really know
17 what's going on though, I'm afraid, so I have to ask
18 these questions, because the presentation doesn't tell
19 me unless I ask them, but I'll try to be brief.

20 MR. GALLAGHER: Okay, so leaving the
21 embed, the drywell shell in the sandbed region was
22 then coated. The coating that was applied was
23 application of a three-coat epoxy coating system
24 consisting of one coat of primer and two coats of
25 epoxy coating. Each coat was visually examined and

1 dry film thickness measurements were taken to assure
2 the proper coating thickness was achieved. The
3 coating is a two-part 100 percent solid epoxy coating
4 which is less susceptible to the degradation and moist
5 environments. The coating was tested to qualify for
6 emersion surface coating applications such as tank
7 linings. The surrounding environment has stable
8 temperature conditions resulting in lower thermal
9 stresses being applied to the coating and therefore,
10 provides close to an ideal service environment which
11 will result if a very long service life.
12 MR. BARTON: Do you have any idea how long
13 that coating would be good for, the epoxy coating?
14 MR. GALLAGHER: We can have Ahmed answer
15 that question.
16 MR. OUAOU: There were some estimates done
17 by our engineering and it varied from 10 years to 20
18 years. Recently we spent a lot of time talking to the
19 vendor about the qualification of the coating and the
20 feedback we're getting is that there is no guarantee
21 for that coating, whether it is 20 years, 15 years,
22 whatever. However, you can rely on your inspections
23 to give you an indication whether you're approaching
24 the end life of the coating. So the rigor inspection
25 is the gauge as to when we think that coating is to

1 company of Exelon/Amergen understands how the
2 commitment was met at this time and it has taken
3 corrective actions to insure that doesn't happen again
4 in terms of addressing the question of how can we feel
5 confident going forward that we won't have a similar
6 occurrence. Thank you.
7 MR. GALLAGHER: Okay. I believe we're on
8 Slide 15 now, which --
9 MEMBER SIEBER: Before you escape from
10 this slide, I do have a question. You talk about
11 taking UT measurements, thickness measurements of the
12 shell. And it was stated that the corrosion of the
13 shell was not uniform and, therefore, when you take
14 individual point measurements, even in a grid or the
15 thousand measurements that you talked about on the
16 previous slide, there is some probability that there
17 is a thinner place than what you've measured. And so,
18 you can't just assume that here's the minimum
19 thickness I can tolerate to withstand the pressure of
20 the -- the accident pressure. You have to have some
21 margin that's statistically based between your minimum
22 measured thickness and the minimum or the minimum
23 allowed thickness for the pressure. Have you done
24 that work and has the staff reviewed it?
25 MR. GALLAGHER: Pete?

1 MR. TAMBURNO: Yes, we've done that work.
2 We've taken the data for the upper regions and applied
3 a 95 percent confidence intervals on the data and also
4 in the sandbeds.
5 MEMBER ABDEL-KHALIK: How about the
6 embedded region?
7 MR. TAMBURNO: The embedded region has not
8 been inspected.
9 MEMBER ABDEL-KHALIK: So do you have
10 confidence that the thickness in that region will be
11 greater than .8 inches?
12 MR. OUAOU: This is Ahmed with Exelon. We
13 have confidence that the corrosion incentive bed
14 region and the embedded region it will not be greater
15 than the sandbed region itself. And since we use the
16 same analysis and the same minimum thickness, we
17 believe that balance the potential of having corrosion
18 in the embedded region. And --
19 MEMBER ABDEL-KHALIK: Where does your
20 confidence come from?
21 MR. OUAOU: We have consulted with
22 corrosion experts. We looked at the environment that
23 the embedded shell is going to be subjected to. Based
24 on that, our consultants indicated that the corrosion
25 in the embedded shell will not be greater, should not

1 be greater than the sandbed region area.

2 MEMBER SHACK: Well, that's certainly true

3 from when you had active ongoing corrosion in the

4 sandbed. You know, I'd fully accept that argument

5 that it would be less. Now, that you've arrested the

6 corrosion in the sandbed, what's your assurance of the

7 environment within there. That really comes down to

8 the integrity of the silicon seal.

9 MR. OUAOU: And in response to that

10 question, we agree with you. The fact that the seal

11 itself now protects the embedded shell. We inspect

12 the seal with we inspect the coating mixture of that

13 it is not cracked or it is not damaged such that any

14 potential moisture will get in the embedded shell.

15 MEMBER SHACK: And there's no other access

16 path for water to that embedded region.

17 MR. OUAOU: No.

18 MEMBER WALLACE: This 95 percent

19 confidence seems to me an important issue. If you do

20 a statistical analysis, it should be part of your

21 presentation. It's a good piece of evidence and it

22 should be there. We shouldn't have to drag it out of

23 you and it should be explained fully so we know what

24 it was. Is it a confidence that the thickness is

25 bigger than .736 where there's 95 percent probability

1 and blah, blah, blah, or is it bigger than .72 or what
2 it is? Give us the numbers, otherwise it's all vague.
3 MEMBER ARMIJO: Well, I'd like to add that
4 your Table 1 in your June 20th letter to the NRC shows
5 that in the embedded region you have almost three
6 times as much margin for the lower sphere even if you
7 assume that that region which you couldn't inspect,
8 corroded down to .8 inches. And you know, again,
9 beating a dead horse on this table, but this table is
10 very informative. I got a lot out of it. I wish we
11 could all have had it in the presentation.
12 MR. GALLAGHER: Okay, a point well-taken.
13 We'll -- I again apologize for not having that in
14 there.
15 Okay, if we could move onto Slide 15 then,
16 which at this point in the presentation we've put the
17 corrective actions in place and then after the
18 corrective actions were implemented, the effectiveness
19 was then determined. And we took UT thickness
20 measurements in 1992 and again, in 1994 in the sandbed
21 region and confirmed that the corrosion in the sandbed
22 region had been arrested. UT measurements were also
23 taken in 1996. However, there were some anomalies in
24 this data. In some cases, the values were greater
25 than previously measured.

1 kind of safety margin. So a small thin spot wasn't
2 going to matter.
3 Again we're confirming their number.
4 We're not trying to independently calculate something
5 that's totally ours.
6 CHAIR MAYNARD: Can we go on?
7 MR. ASHER: Thank you very much. I want
8 to talk a little about commitment in the open items.
9 I want to just point out a few things in the open
10 items.
11 (Off the record comments.)
12 CHAIR MAYNARD: Okay. Could we pay
13 attention here? Okay. Go ahead.
14 MR. ASHER: Yes. These are the five open
15 items we have right now and during the Applicant's
16 presentation, it said that the first open item is the
17 one that they are working on and they are going to put
18 in stove one, they are going to put four probes which
19 results in the area of the drywell shell and they say
20 that other four are accepted by NRCI. I disagree with
21 that. The OI on the embedded shell is not something
22 that we have completely zeroed in on because
23 quantitatively the Applicant provided a pretty
24 convincing response qualitatively that it is a
25 concrete environment and it is a new chance of having

1 oxygen getting into that area and at the most what it
2 can do is not less than 0.732 or whatever they had
3 shown in there. That was their argument and
4 qualitatively I tend to agree with that argument.
5 But I do feel that they should show some
6 maybe chipping concrete in a particular area where the
7 damage had been the most, for example, in the sand bed
8 area to show that there's no corrosion here or there's
9 a minimum corrosion. Something has to be done in that
10 area.
11 We also provided an NXER report that the
12 Office of Research had developed earlier where they
13 can really find the thickness of the matter between
14 the embedded shell. These are guided but they are
15 more experimental in nature. I did request the
16 Applicant to explore some of them to see if they can
17 find something, to see if the metal thickness can be
18 measured somehow.
19 So embedded shell is still the annoying
20 one. It's very difficult to -- Qualitatively as I say
21 I agree with their arguments, but quantitatively I
22 don't have anything to go by.
23 The other three I agree with the
24 Applicant's conclusion that we have taken care of
25 through commitments and everything else.

1 MEMBER ARMIJO: I think -- I keep going
2 back to this one table in that June 20th letter. I
3 think it was a response to a request for additional
4 information. The Applicant submitted data showing the
5 margin for the lower sphere which I presume is the
6 embedded part of the containment. Is that correct?
7 MR. ASHER: No, the lower sphere includes
8 the sand bed area.
9 MEMBER ARMIJO: They have a separate line
10 for sand bed than they have for the lower sphere. But
11 you're saying the lower sphere is let's say below the
12 equator. Is that --
13 MEMBER SIEBER: Below the knuckle.
14 MEMBER ARMIJO: Below the knuckle. All
15 right. I understand now.
16 MR. ASHLEY: Thank you Hans. Which brings
17 up to our conclusion. The staff has concluded that
18 the depending resolution of the open items that there
19 is reasonable assurance that the activities authorized
20 by the renewed license will continue to be conducted
21 in accordance with the current licensing basis; that
22 any changes made to the Oyster Creek current licensing
23 basis in order to comply with 10 CFR 5429(a) or in
24 accordance with the Act and the Commission's
25 regulations.

1 CHAIR MAYNARD: Appreciate it. I would
2 just like to make sure everybody realizes that that's
3 the conclusion that you're presenting. That's not the
4 ACRS conclusion at this point. The ACRS has not made
5 any conclusion and still has quite a bit more to take
6 a look at. So I want to make sure that people
7 understand that's not an ACRS conclusion.
8 With that, I'd like to -- I believe that
9 we have -- That does complete the NRC staff's
10 presentation.
11 MR. GILLESPIE: Yes.
12 MEMBER WALLIS: Can I say something about
13 this? I've been looking at the original data here
14 from GPU and trying to figure it out and trying to see
15 how on earth it's related to the stuff that was
16 displayed in the Sandia study and it looks very
17 interesting and I think they need to be put side by
18 side so someone can explain to me how you go from the
19 measurements and the places where it was measured to
20 the actual numbers that were put into the computer
21 program so we can understand that process and it's a
22 believable one. Otherwise, there are just too many
23 ifs and it may well be it's right. It looks to me
24 looking at it superficially as if someone has made an
25 effort to be conservative and take the lowest value

AmerGen

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20414
October 20, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: AmerGen Responses to Open Items Associated with the NRC Draft Safety Evaluation for the Oyster Creek Generating Station Application for License Renewal (TAC No. MC7624)

Reference: NRC Letter "Safety Evaluation Report with Open Items Related to the License Renewal of Oyster Creek Generating Station," dated August 18, 2006

In the referenced letter, the NRC issued its Safety Evaluation Report (SER) with Open Items related to License Renewal of the Oyster Creek Generating Station. In Section 1.5 of its Safety Evaluation, the NRC identified five Open Items, all related to the Staff's evaluation of the drywell corrosion issue.

Enclosure 1 of this letter provides the responses to these Open Items. Enclosure 2 provides an update to the License Renewal Application Commitment List (LRA Appendix A, Table A.5) to reflect a modification to commitment # 27, which incorporates actions planned in response to Open Item 4.7.2-1.1.

In its August 18, 2006 letter, the NRC also requested AmerGen to review the SER for accuracy and provide comments to the Staff. AmerGen letter 2130-06-20400, also dated October 20, 2006, provides those comments.

If you have any questions, please contact John Hufnagel, Licensing Lead, at 610-765-5829.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 10-20-06

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosures: 1. AmerGen Responses to Draft SER Open Items
2. Revised Commitment # 27 of AmerGen's A.5 Commitment List

cc: Regional Administrator, USNRC Region I, w/o Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

Enclosure 1

AmerGen Responses to Open Items Identified in NRC Draft License Renewal Safety Evaluation for the Oyster Creek Generating Station

This Enclosure provides the AmerGen response to each of the five open items identified by the NRC Staff in Section 1.5 of the draft SER. For completeness, each open item (OI) is repeated here, followed by the AmerGen response.

Open Item # 1 - OI 4.7.2-1.1:

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

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

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

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

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

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

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

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

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

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

as those performed on the upper region of the drywell (every other refueling outage).

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

AmerGen Response to Open Item # 1 – OI 4.7.2-1.1

AmerGen will perform four separate sets of UT examinations of the drywell shell at two areas where there is a transition between shell plate thicknesses (i.e., four separate 49-point UT sets at the transition at elevation 23', 6 7/8" and four sets of UTs at elevation 71' 6."). These measurements will be performed prior to the period of extended operation. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage).

This commitment will be added to AmerGen's A.5 Commitment List (modifying Appendix A of the License Renewal Application), as identified in the mark-up to Commitment # 27, which is included as Enclosure 2 to this letter.

Open Item # 2 - OI 4.7.2-1.2:

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

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

In its response dated June 20, 2006, the applicant noted that the drywell construction and fabrication details show that the presence of the drywell skirt prevents moisture

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

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

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

AmerGen Response to Open Item # 2 - OI 4.7.2-1.2

In this Open Item, the Staff questions whether the drywell shell corrosion sampling plan is adequate with respect to the lower (embedded) region of the shell. On pages 10 through 13 of Letter 2130-06-20353 dated June 20, 2006, AmerGen provided detailed information responding to the staff's concerns in this area. This information was acknowledged by the Staff as useful in addressing the issue, in both the draft SER and in more recent telephone discussions, but the Staff indicated it was still evaluating the issue.

The 1.154 inch thick plate between the support skirt and the floor of the sandbed region is likely to have experienced some corrosion due to the water from the sandbed region; however, this corrosion would not be worse than the corrosion in the sandbed region and is likely to be less due to the formation of a thin protective oxide passive film from the highly alkaline concrete. Once this area was sealed off from the sandbed region and any further water intrusion was prevented, the corrosion mechanism in this area would be stopped. AmerGen continues to believe that the 0.676 inch thick plate embedded in

the concrete below the attachment point of the support skirt has always been and continues to be protected from coming in contact with water from the sandbed region and; therefore, does not represent a corrosion issue.

The Staff encouraged AmerGen to investigate the feasibility of applying state-of-the-art non-destructive examination techniques to see if any could be effectively used to investigate the condition of the embedded region. AmerGen has contacted EPRI and other utilities that potentially used such techniques. Based on these discussions, we understand that a "guided wave" technology has been developed that may be able to provide some qualitative information on whether the embedded shell has undergone corrosion. However, neither this nor any other non-destructive methods have been identified that could determine the thickness of the embedded drywell shell or the specific extent of corrosion. Therefore, AmerGen does not plan to further pursue use of such techniques at this time.

Based on discussions with the Staff, AmerGen owes no additional information to the Staff at this time in order to support closure of this issue.

Open Item # 3 - OI 4.7.2-1.3:

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

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

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

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

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

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

The staff believes that the applicant has provided a thorough explanation of the factors considered in applying the ASME Code Case N-284-1 for buckling analysis of the corroded shell in the sand bed area of the drywell shell. However, the applicant did not address whether it is appropriate to assume the same strength across the corroded section of the shell. The incorporation of the "e/t" corrosion concept with a representative distribution of strength along the corroded section that recognize the lower strength at the corroded side and full strength at the inside surface, could support the claim of conservatism in the analysis. This has been identified as an OI.

AmerGen Response to Open Item # 3 – OI 4.7.2-1.3

On pages 8 and 9 of its June 20, 2006 letter (2130-06-20353) addressing drywell corrosion issues, AmerGen provided detailed technical information supporting the use of Code Case N-284-1 and the rationale for why the corrosion experienced will not cause a drywell structural integrity concern. Based on discussions with the NRC staff, AmerGen owes no additional information to the Staff at this time in order to support closure of this issue.

Open Item # 4 - OI 4.7.2-1.4:

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

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

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

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

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

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

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

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

The staff is still evaluating this item; therefore, it has been identified as an OI.

AmerGen Response to Open Item #4 - OI 4.7.2-1.4

As noted in the Open Item description above, AmerGen provided detailed information on this issue in its Letter 2130-06-20353 dated June 20, 2006. Subsequent discussions with the Staff have indicated that AmerGen owes no additional information at this time to support closure of this Open Item.

Open Item # 5 - OI 4.7.2-3:

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

In its response dated April 16, 2006, the applicant stated that the refueling seals at OCGS consist of stainless steel bellows. In the mid-to-late 1980s, GPU conducted extensive visual and NDE inspections to determine the source of water intrusion into the

seismic gap between the drywell concrete shield wall and the drywell shell and accumulation in the sand bed region. The inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested by helium (external) and air (internal) with no indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in a concrete trough below the bellows. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the seismic gap. The drain line has been checked before refueling outages to confirm that it is not blocked. The only other seal is the gasket for the reactor cavity steel trough drain line. This gasket was replaced after the tests showed that it was leaking. However, the gasket leak was ruled out as the primary source of water observed in the sand bed drains because there is no clear leakage path to the seismic gap. Minor gasket leaks would be collected in the concrete trough below the gasket and would be removed by the drain line like leaks from the refueling bellows.

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

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

The applicant also committed (Commitment No. 33) to augmented inspections of the drywell in accordance with ASME Code Section XI, Subsection IWE. These inspections consist of UT examinations of the upper region of the drywell and visual examinations of the protective coating on the exterior of the drywell shell in the sand bed region. UT measurements will supplement the visual inspection of the coating measurements from inside the drywell once before entering the period of extended operation and every 10 years during the period of extended operation.

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

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

AmerGen committed that it will monitor the sand bed region drains on a daily basis during refueling outages and take the following actions if water is detected. The actions will be completed prior to exiting the outage.

- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
- The water will be chemically analyzed to aid in determining the source of leakage.
- A remote inspection will be performed in the trough drain area to determine if the trough drains are operating properly.
- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected.
- If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation will be consistent with the existing program.
- The degraded coating and/or the seal will be repaired in accordance with station procedures.
- UT measurements will be taken in the upper region of the drywell consistent with the existing program.

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

- The leakage rate will be quantified to determine a representative flow rate. The leakage rate will be trended.
- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
- The water will be chemically analyzed to determine the source of leakage.
- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected during the next refueling outage or an outage of opportunity.
- If the coating is degraded and visual inspection indicates corrosion has taken place, then UT thickness measurements will be taken in the affected areas of the sand bed region from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation of the results will be consistent with the existing program.

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

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

The staff believes that applicant has not provided sufficient information regarding the extent that coated surfaces will be examined during each inspection. This has been identified as an OI.

AmerGen Response to Open Item #5 - OI 4.7.2-3

Based on further discussions with the Staff, it was determined that AmerGen has submitted sufficient information regarding the coating inspections to be performed. No additional information is needed from AmerGen to support closure of this Open Item.

Enclosure 2

Update to Oyster Creek License Renewal Application Appendix A Table A.5 (Commitment List) Commitment 27 Incorporating Inspections to be Performed in Response to Open Item 4.7.2-1.1

Note: Changes to previous commitment are identified in **bold** font.

Item Number	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: 1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years , except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity.	A.1.27	Prior to the period of extended operation Prior to the period of extended operation, and then two refueling outages after that. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals

Item Number	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE
	• Perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.		
	2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.		Refueling outages prior to and during the period of extended operation
	3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage.		Periodically
	• 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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.		Daily during refueling outages

Item Number	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE
	• The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage: • Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program Any degraded coating or moisture barrier will be repaired.		Quarterly during non-outage periods
	4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These		Prior to the period of extended operation and every ten years during the period of extended operation

Item Number	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE
	inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.		
	5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.		Prior to the period of extended operation
	6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to and during the period of extended operation
	7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently		Every other refueling outage prior to and during the period of

Item Number	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE
	measured.		extended operation
	8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.		
	9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).		Prior to the period of extended operation
	10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at **four** locations using the 6"x6" grid. **The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage).** These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the		Prior to the period of extended operation and two refueling outages later

Item Number	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE
	upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		
	11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at **four** locations using the 6"x6" grid. **The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage).** These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later
	12. When the sand bed region drywell shell coating inspection is performed (commitment 27, item 4), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.		Coincident with the sand bed region drywell shell coating inspection
	13. The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.		Once per refueling cycle

3.8.2.8 Drywell Corrosion

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

The upper regions of the vessel, above the sand bed, were handled separately from the sand bed region because of the significant difference in corrosion rate and physical difference in design. Corrective action for the upper vessel involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. **Amendment 165 to the Oyster Creek Technical Specification (Ref. 48) reduced the drywell design** pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the vessel and the concrete will allow the upper portion of the vessel to meet ASME code for the remainder life of the plant.

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

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

During 14R, UT measurements were taken from the outside surface of the drywell vessel in the sand bed region. Measurements were taken in each of the ten sand bed bays. The results of this inspection and the structural evaluation of the "as found" condition of the vessel is contained in Reference 44. As documented in the TDR, the vessel was evaluated to conform to ASME code requirements given the deteriorated thickness condition. In general these measurements verified projections that had been made based on measurements taken from inside the drywell. Several areas were thinner than projected. In all cases these areas were found to meet ASME code requirements after structural analysis.

The cleaning, floor refurbishing and coating effort completed in 14R will mitigate corrosion in the sand bed area. Since this was accomplished while the vessel thickness was sufficient to satisfy ASME code requirements, drywell vessel corrosion in the sand bed region is no longer a limiting factor in plant operation. Inspections will be conducted in future refueling outages to ensure that the coating remains effective. In addition, UT measurements will also be taken from inside the drywell. The frequency and extent of the coating inspections and UT thickness measurements will be per Reference 47, as follows:

1. For the upper elevations, UT measurements will be made during the 16th refueling outage (September, 1996) and during every second refueling outage, thereafter. After each inspection, a determination will be made if additional inspection is to be performed.

2. For the sandbed region, visual inspection of the coating as well as UT measurements of the shell will be made during the 16th refueling outage. **UT measurements and sandbed coating inspections were again performed during the 18th and 20th refueling outages (2000 and 2004).** Based on the results of the inspection of the coating, determinations will be made for additional inspections.

3. For water leakage not associated with refueling activities, an investigation will be made as to the source of the leakage. **Oyster Creek** will take corrective actions, evaluate the impact of the leakage and, if necessary, perform an additional drywell inspection about three months after the discovery of the water leakage.

Reference **51** provides the evaluation of the latest drywell UT inspections through the next scheduled inspection.

Oyster Creek will notify NRC prior to implementing any changes to the drywell thickness measurement inspection program (Reference 43).

AmerGen

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10 CFR 50
10 CFR 51
10 CFR 54

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December 3, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Information from October 2006 Refueling Outage Supplementing AmerGen Energy Company, LLC (AmerGen) Application for a Renewed Operating License for Oyster Creek Generating Station (TAC No. MC7624)

References:

1. AmerGen's "Application for Renewed Operating License," Oyster Creek Generating Station, Letter 2130-05-20135, dated July 22, 2005

2. AmerGen's "Response to NRC Request for Additional Information, dated March 10, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," Letter 2130-06-20289, dated April 7, 2006

3. AmerGen's "Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)," Letter 2130-06-20353, dated June 20, 2006

4. AmerGen's "Additional Information Concerning FSAR Supplement Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," Letter 2130-06-20358, dated July 7, 2006

In References 1 through 4, AmerGen provided detailed information describing aging management reviews, aging management programs and commitments for future actions associated with the primary containment drywell shell, as part of its license renewal application (LRA) for the Oyster Creek Generating Station (Oyster Creek). In its recently completed Oyster Creek refueling outage, AmerGen performed many of the drywell shell inspection activities that it had committed to perform prior to the period of extended operation.

Per 10 C.F.R. § 54.21, this submittal serves to update the LRA and the other referenced submittals with the results of the 2006 outage activities. For ease of review, various sections of the original LRA and related responses to NRC requests for additional information (RAIs) have been updated to reflect the latest information. To a great extent, the information learned during this outage confirmed the condition of the drywell as described in previous submittals.

However, as a result of performing planned inspections of the internal surface of the drywell shell in the trenches excavated in the concrete floor in 1986, AmerGen identified an environment/material/aging effect combination that was not included in the LRA. Aging management reviews of this combination have been performed and, as a result, AmerGen has identified additional aging management activities that will be included in aging management programs associated with the drywell.

The Enclosure to this letter more fully describes these reviews and resultant aging management activities. Updates to the affected portions of the LRA are provided, including a revision to the License Renewal Commitment List (LRA Appendix A, Section A.5). The Commitment List update clearly indicates the activities that are being added as part of this submittal.

AmerGen has performed a review to determine whether any additional aspects of the LRA require updating, given the recent identification of a new environment requiring evaluation in support of license renewal. Based on its review, AmerGen concludes that there are no additional revisions required to the LRA. This review has been documented in the corrective action program.

In addition, a consolidated summary of key drywell-related inspections conducted during the outage, with a summary of the results, is provided in the Enclosure.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 12/03/2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosure: LRA Supplemental Information, Post-2006 Refueling Outage

cc: Regional Administrator, USNRC Region I, w/ Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/ Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

Enclosure

License Renewal Application
Supplemental Information
Post-2006 Refueling Outage

Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

Note: **Bold** font has been used to designate additions made by this submittal to previously submitted documents.

Summary of Post-2006 Refueling Outage Supplement

This submittal is being made to update the LRA with information that was identified during the October/November 2006 (1R21) refueling outage. Included in this update are the results of various inspections and activities performed which relate to the condition of the drywell shell. Also, the LRA is being updated to reflect the identification of water in contact with the lower portion of the inside surface of the drywell shell.

As noted, this submittal provides the results of numerous visual and ultrasonic examinations performed on the drywell shell during the 1R21 refueling outage. These results serve to confirm the condition of the drywell shell as discussed in previous LRA correspondence.

During inspections of the drywell shell that were performed as part of planned license renewal commitment implementation, water was identified in contact with the interior surface of the drywell shell within an inspection access trench. Moisture was identified on the shell in a second trench. This was indicative of water beneath the drywell floor surface, being in contact with both the drywell shell and drywell concrete. Although water is present at times within the drywell during plant operation, LRA preparation activities did not identify this specific condition as a normal operating environment requiring aging management review and ongoing aging management activities because the drywell floor, curb and drainage system were designed to keep water away from the shell.

AmerGen entered this condition into its corrective action program. Various investigations and corrective actions were undertaken during the outage to understand the condition and to minimize water from coming into contact with the drywell shell and embedded concrete in the future. Corrective actions implemented during 1R21 included repair of the drywell drainage trough and installation of a moisture barrier between the drywell shell and concrete curb adjacent to the drywell floor. As described further in this Enclosure, AmerGen has also performed analysis concluding that the impact of water on the inner surface of the drywell shell and concrete fill slab is insignificant. However, AmerGen has decided to treat the entire internal surface of the lower drywell shell as a wetted component from an aging management perspective. Based upon this approach, additional aging management review activities have been performed and aging management program activities established for the drywell shell and moisture barrier. No additional aging management activities are required for the drywell concrete.

This submittal provides the results of these reviews, including new aging management program activities and associated aging management commitments. For ease of comparison, the results of the outage inspections and aging management reviews are presented as updates to previously submitted LRA information and RAI responses. A consolidated summary of 1R21 drywell inspection activities, correlated to IWE Inspection Program commitments, is also provided.

A specific listing of the contents of this Enclosure is provided on the next page.

Enclosure Contents

Note: **Bold** font has been used to designate additions made by this submittal to previously submitted documents.

2.4.1 Primary Containment

System Purpose

The Primary Containment Structure is comprised of the primary containment, containment penetrations, and internal structures. The structure is enclosed by the Reactor Building, which provides secondary containment, structural support, shielding, shelter, and protection, to the containment and components housed within, against external design basis events.

The primary containment is a General Electric Mark I design and consists of a drywell, a pressure suppression chamber, and a vent system connecting the drywell and the suppression chamber. It is designed, fabricated, inspected, and tested in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, and Nuclear Code Cases1270N-5, 1271N and 1272N-5. The containment is safety related, classified Seismic Class 1 structure.

The drywell is a steel pressure vessel, in the shape of an inverted light bulb, with a spherical lower section and a cylindrical upper section. The lower spherical section is embedded externally in the reinforced concrete foundation and covered internally by a fill slab at the bottom of the drywell. The top portion of the drywell vessel consists of a steel head that is removed during refueling operations. The head is bolted to the drywell flange and is sealed with a double seal arrangement. Access into the drywell is through a personnel airlock/equipment hatch, with two mechanically interlocked doors, and other access hatches. The drywell houses the reactor pressure vessel, the reactor coolant recirculation system, safety relief valves, electromatic relief valves (EMRVs), branch connections of the reactor primary system, containment drywell spray header, and internal structures discussed below. The drywell shell and the enclosing reactor building concrete are separated by an air gap to allow for differential thermal expansion between the shell and the concrete during any mode of plant operation.

The pressure suppression chamber is a toroidal shaped, steel pressure vessel encircling the base of drywell. The suppression chamber, commonly called the torus, is partially filled with demineralized water and includes internal steel framing, and access hatches. The suppression chamber is mounted on support structures that transmit loads to the reactor building foundation. Major components inside the suppression chamber include Emergency Core Cooling Systems (ECCS) suction strainers, which are connected to the ECCS suction header located outside the chamber, torus spray header, and Y-Quenchers.

The vent system consists of ten circular vent lines, which form a connection between the drywell and the pressure suppression chamber. The lines enter the suppression chamber through penetrations provided with expansion bellows and join into a common header contained within the air space of the suppression chamber. The header discharge is through 120 downcomer pipes, which terminate below the water level in the torus. The header and the downcomer pipes are supported from the suppression chamber shell.

The primary containment is provided with a vacuum breaker system to equalize the pressure between the drywell and the suppression chamber, and between the suppression chamber and the reactor building. The vacuum breaker system assures that the external design pressure limits of the two chambers are not exceeded.

The primary containment is penetrated at several locations by piping, instrument lines,

ventilation ducts, and electric leads. The penetrations consist of sleeves welded to drywell vessel or suppression chamber and are of two general types. Those required to accommodate thermal movements; and those, which experience relatively little thermal stress. Penetrations required to accommodate thermal movements are provided with expansion bellows.

Internal structures consist of a fill slab, reactor pedestal, biological shield wall and its lateral support, and structural steel. The fill slab is reinforced concrete placed in the bottom of the drywell to provide a working base for supporting the reactor pedestal and other structures and components inside the drywell. **A curb is provided above the fill slab around the drywell perimeter to prevent any water that collects on the floor from being in contact with the drywell shell. The curb is removed at two locations where 2 trenches were excavated on the floor to allow UT thickness measurements to be taken below the floor. A moisture barrier was added at the junction of the curb and the drywell shell and inside the trenches, during 2006 refueling outage to prevent water and moisture intrusion into the embedded drywell shell.**

The reactor pedestal is a reinforced concrete cylinder with an outside diameter of 26 feet. The pedestal provides structural support to the reactor pressure vessel, the biological shield wall, and floor framing. The biological shield wall extends above the reactor pedestal and is a composite steel, concrete cylinder with an inside diameter of approximately 21 feet. The wall is framed with steel columns covered with steel plate on each face and filled partly with normal density concrete and partly with high-density concrete. The top of the wall is capped with a steel plate and laterally braced to the drywell vessel.

Structural steel includes floor framing steel for the platforms inside the drywell, and a catwalk inside the suppression chamber. It also includes miscellaneous steel inside the containment such as grating, ladders, connection plates; electrical cable trays, and electrical conduits.

The purpose of the primary containment is to accommodate, with a minimum of leakage, the pressures and temperatures resulting from the break of any enclosed process pipe; and thereby, to limit the release of radioactive fission products to values, which will insure offsite dose rates well below 10CFR100 guideline limits. It also provides a source of water for ECCS and for pressure suppression in the event of a loss-of-coolant accident. The primary containment and internal structures also provide structural support to the reactor pressure vessel, the reactor coolant systems, and other safety and nonsafety related systems, structures, and components housed within. The biological shield wall provides the added function of radiation shielding to maintain drywell environment within equipment qualification parameters.

Included in the evaluation boundary of the Primary Containment are the drywell, drywell head, suppression chamber, vent lines, downcomers, drywell and suppression chamber penetrations, vent line bellows, drywell penetration bellows, personnel air lock/equipment and other hatches, pressure retaining bolting, thermowells, and internal structures listed above.

Not included in the evaluation boundary of the Primary Containment are safety relief valves and EMRVs, EMRV discharge lines, Y-Quenchers, drywell and torus spray headers, vacuum breakers, ECCS suction strainers and header, downcomer bracing, suppression chamber (torus) supports, and other component supports. These components are separately evaluated with their respective license renewal systems. That is, safety relief valves, EMRVs, EMRV discharge lines, and Y-Quenchers are evaluated with Main Steam System. Drywell and torus spray headers, and ECCS suction strainers and header are evaluated with the Containment Spray System. Vacuum breakers are evaluated with the Containment Vacuum Breakers

System. Downcomer bracing, suppression chamber supports, and other component supports are evaluated with the Component Supports Commodity Group.

For more detailed information, see UFSAR Sections 3.8 and 6.2

Reason for Scope Determination

The Primary Containment meets the scoping requirements of 10 CFR 54.4(a)(1) because it is a safety-related structure which is relied upon to remain functional during and following design basis events. It meets 10 CFR 54.4(a)(2) because failure of nonsafety related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). It also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), ATWS (10 CFR 50.62), and Environmental Qualification (10 CFR 50.49). The Primary Containment is not relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with Station Blackout (10 CFR 50.63).

System Intended Functions

1. Controls the release of fission products to the secondary containment in the event of design basis loss-of-coolant accidents (LOCA) so that off site consequences are within acceptable limits. (10 CFR 54.4(a)(1))
2. Provides sufficient air and water volumes to absorb the energy released to the containment in the event of design basis event so that pressure is within acceptable limits. (10 CFR 54.4(a)(1))
3. Provides a source of water for core spray, containment spray, and condensate transfer systems. (10 CFR 54.4(a)(1))
4. Provides physical support, shelter, and protection for safety related systems, structures, and components (SSCs). 10 CFR 54.4(a)(1)
5. Provides physical support, shelter, and protection for nonsafety related systems, structures, and components (SSCs) whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)

UFSAR References

3.8
6.2

License Renewal Boundary Drawings

LR-JC-19702

Table 2.4.1 **Primary Containment**
Components Subject to Aging Management Review

Component Type	Intended Functions
Access Hatch Covers	Pressure Boundary
Beam Seats	Structural Support
Biological Shield Wall - Concrete	Shielding
Biological Shield Wall - Lateral Support	Structural Support
Biological Shield Wall - Liner Plate	Structural Support
Biological Shield Wall - Structural Steel	Structural Support
Cable Tray	Structural Support
Class MC Pressure Retaining Bolting	Pressure Boundary
Concrete embedment	Structural Support
Conduits	Enclosure Protection
	Structural Support
Downcomers	Pressure Boundary
Drywell Head	Pressure Boundary
	Structural Support
Drywell Penetration Bellows	Pressure Boundary
Drywell Penetration Sleeves	Pressure Boundary
	Structural Support
Drywell Shell	Pressure Boundary
	Structural Support
Drywell Support Skirt	Structural Support
Liner (Sump)	Leakage Boundary
Locks, Hinges, and Closure Mechanisms	Pressure Boundary
	Structural Support
Miscellaneous Steel (catwalks, handrails, ladders, platforms, grating, and associated supports)	Structural Support
Moisture Barrier	**Leakage Boundary**
Panels and Enclosures	Enclosure Protection
	Structural Support
Penetration Closure Plates and Caps (spare penetrations)	Pressure Boundary
Personnel Airlock/Equipment Hatch	Pressure Boundary
Reactor Pedestal	Structural Support
Reinforced Concrete Floor Slab (fill slab)	Enclosure Protection
	Structural Support
Seals, Gaskets, and O-rings	Pressure Boundary
Shielding Blocks and Plates	Shielding
Structural Bolting	Structural Support
Structural Steel (radial beams, posts, bracing, plate, connections, etc.)	Structural Support
Suppression Chamber Penetrations	Pressure Boundary
	Structural Support
Suppression Chamber Ring Girders	Structural Support

Suppression Chamber Shell	Pressure Boundary
	Structural Support
Suppression Chamber Shell Hoop Straps	Structural Support
Thermowells	Pressure Boundary
Vent Header Deflector	HELB Shielding
Vent Jet Deflectors	HELB Shielding
Vent line bellows	Pressure Boundary
Vent line, and Vent Header	Pressure Boundary

The aging management review results for these components are provided in
Table 3.5.2.1.1 Primary Containment
-Summary of Aging Management Evaluation

3.5.2.2 AMR Results Consistent With The GALL Report for Which Further Evaluation is Recommended

NUREG 1801 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the LRA. For the Containments, Structures, and Component Supports, those programs are addressed in the following subsections.

3.5.2.2.1 PWR and BWR Containments

1. Aging of Inaccessible Concrete Areas

   Cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in inaccessible areas of PWR concrete and steel containments; BWR Mark II concrete containments; and Mark III concrete and steel containments. The GALL report recommends further evaluation to manage the aging effects for inaccessible areas if the environment is aggressive.

   This is applicable only to PWR and BWR concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

2. Cracks and distortion due to increased stress levels from settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program

   Cracking, distortion, and increase in component stress level due to settlement could occur in PWR concrete and steel containments and BWR Mark II concrete containments and Mark III concrete and steel containments. Also, reduction of foundation strength due to erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. Some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system, the GALL report recommends verification of the continued functionality of the de-watering system during the period of extended operation. The GALL report recommends no further evaluation if this activity is included in the scope of the applicant's structures monitoring program.

   This is applicable only to PWR and BWR concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

3. Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

   Reduction of strength and modulus of elasticity due to elevated temperatures could occur in PWR concrete and steel containments and BWR Mark II concrete containments and Mark III concrete and steel containments. The GALL report recommends further evaluation if any

portion of the concrete containment components exceeds specified temperature limits, i.e., general area temperature 66°C (150°F) and local area temperature 93°C (200°F).

The normal operating temperature inside the Oyster Creek Primary Containment drywell varies from 139°F (at elev. 55') to 256°F (at elev. 95'). The containment structure is a BWR Mark I steel containment, which is not affected by general area temperature of 150°F and local area temperature of 200°F. Concrete for the reactor pedestal, and the drywell floor slab (fill slab) are located below elev. 55' and are not exposed to the elevated temperature. The biological shield wall extends from elev. 37'-3" to elev. 82'-2" and is exposed to a temperature range of 139°F - 184°F. The wall is a composite steel-concrete cylinder surrounding the reactor vessel. It is framed with 27 in. deep wide flange columns covered with steel plate on both sides. The area between the plates is filled with high density concrete to satisfy the shielding requirements. The steel columns provide the intended structural support function and the encased high density concrete provides shielding requirements. The encased concrete is not accessible for inspection.

The elevated drywell temperature concern was evaluated as a part of the Integrated Plant Assessment Systematic Evaluation Program (SEP Topic III-7.B). The evaluation concluded that the temperature would not adversely affect the structural and shielding functions of the wall.

The elevated drywell temperature was also identified as a concern for the reactor building drywell shield wall. Further evaluation for this wall is discussed in subsection 3.5.2.2.2, item (8).

4. Loss of Material due to General, Pitting, and Crevice Corrosion in Inaccessible Areas of Steel Shell or Liner Plate

   Loss of material due to general, pitting and crevice corrosion could occur in inaccessible areas of the steel containment shell or the steel liner plate for all types of PWR and BWR containments. The GALL report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if specific criteria defined in the GALL report cannot be satisfied.

   At Oyster Creek, the potential for loss of material, due to corrosion, in inaccessible areas of the containment drywell shell was first recognized in 1980 when water was discovered coming from the sand bed region drains. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken during the 1986 refueling outage. As a result, several corrective actions were initiated to determine the extent of corrosion, evaluate the integrity of the drywell, mitigate accelerated corrosion, and monitor the condition of containment surfaces. The corrective actions include extensive UT measurements of the drywell shell thickness, removal of the sand in the sand bed region, cleaning and coating exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. A corrosion monitoring program was established, in 1987, for the drywell

shell above the sand bed region to ensure that the containment vessel is capable of performing its intended functions. Elements of the program have been incorporated into the ASME Section XI, Subsection IWE (B.1.27) and provide for:

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

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

Drywell Shell in the Sand Bed Region:

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

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

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

Because of **the** reduced thickness readings, **two trenches were excavated in 1986 inside the drywell to inspect the embedded drywell shell below the drywell interior concrete floor in areas corresponding to the exterior sandbed region. The sandbed region was inaccessible at that time. UT** thickness measurements were obtained **inside the two trenches in 1986 and in 1988** to determine the vertical profile of the thinning. **One** trench was excavated inside the drywell, in the concrete floor, in the area **corresponding to the exterior sandbed region** where thinning was most severe (**bay #17). A second trench was excavated in bay #5 in the area corresponding to the exterior sand bed region where thinning of the drywell shell at the concrete floor level was less severe. UT m**easurements **of the**

drywell shell exposed in the bay #17 trench demonstrated that thinning of the embedded shell in concrete **was** no more severe than **thinning of the unembedded shell that was already being monitored**. UT measurements **of the drywell shell exposed in the bay #5 trench demonstrated** less significant thinning in the embedded shell. Aside from UT thickness measurements performed by plant staff, independent analysis was performed by the EPRI NDE Center and the GE Ultra Image III "C" scan topographical mapping system. The independent tests confirmed the UT results. The GE Ultra Image results were used as **a** baseline profile to track **future** corrosion.

To validate UT measurements and characterize the form of damage and its cause (i.e., due to the presence of contaminants, microbiological species, or both) core samples of the drywell shell were obtained at seven locations **in 1986**. The core samples validated the UT measurements and confirmed that the corrosion of the **exterior of the** drywell **was** due to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. A contaminate concentrating mechanism due to alternate wetting and drying of the sand may have also contributed to the corrosion phenomenon. It was therefore concluded that the optimum method for mitigating the corrosion **was** by (1) removal of the sand to break up the galvanic cell, (2) removal of the corrosion product from the shell and (3) application of a protective coating.

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

AmerGen had visually inspected (VT-1) the epoxy coating on the exterior of the drywell shell in the sandbed region in selected bays during refueling outages in 1994, 1996, 2000, and 2004. During the 2006 refueling outage (1R21), AmerGen conducted VT-1 inspections of the epoxy coating in all ten bays in accordance with ASME Section XI, Subsection IWE, and AmerGen's Protective Coating

Monitoring and Maintenance Program. These inspections would have documented any flaking, blistering, peeling, discoloration, and other signs of degradation of the coating. The VT-1 inspections found the coating to be in good condition with no degradation.

Based on these VT-1 inspections, AmerGen has confirmed that no further corrosion of the drywell shell is occurring from the exterior of the epoxy-coated sandbed region. Monitoring of the coating in accordance with the ASME Section XI, Subsection IWE and AmerGen's Protective Coating Monitoring and Maintenance Program will continue to ensure that the drywell shell maintains its intended function during the period of extended operation.

Also during the 2006 refueling outage (1R21), AmerGen performed UT of the drywell shell in the sandbed region from inside the drywell, at the same 19 grid locations where UT was performed in 1992, 1994, and 1996. Location of the UT grid is centered at elevation 11'-3" in an area of the drywell shell that corresponds to the sandbed region. The 2006 UT measurements were made and statistically analyzed in accordance with the enhanced Oyster Creek ASME Section XI, Subsection IWE (B1.27) Aging Management Program. The results of the statistical analysis of the 2006 UT data were compared to the 1992, 1994 and 1996 data statistical analysis results (see below). Some of the 1996 data contained anomalies that are not readily justifiable but the anomalies did not significantly change the results. The comparison confirmed that corrosion on the exterior surfaces of the drywell shell in the sandbed region has been arrested.

Analysis of the 2006 UT data, at the 19 grid locations, indicates that the minimum measured 95% confidence level mean thickness in any bay is 0.807" (bay #19). This is compared to the 95% confidence level minimum measured mean thickness in bay #19 of 0.806" and 0.800" measured in 1994 and 1992 respectively. Considering the instrument accuracy of ±0.010" these values are considered equivalent. Thus the minimum drywell shell mean thickness at the grid locations remains greater than 0.736" as required to satisfy the worst case buckling analysis, and the minimum available margin of 64 mils for any bay reported prior to taking 2006 UT thickness measurements remains bounded.

In addition to the UT measurements at the 19 grid locations, a total of 294 UT thickness measurements were taken in the bay #5 trench and 290 measurements were taken in the bay #17 trench during the 2006 refueling outage. The computed mean thickness value of the drywell shell taken within the two trenches is 1.074" for bay #5 and 0.986" for bay #17. These values, when compared to the 1986 mean thickness values of 1.112" for the bay #5 trench and 1.024" for the bay #17 trench, indicated that wall thinning of approximately 0.038" has taken place in each trench since 1986. Engineering evaluation of the results concluded that considering that the exterior surface of

bay #5 had experienced a corrosion rate of up to 11.3 mils/yr between 1986 and 1992 and the exterior surface of bay #17 had experienced a corrosion rate of up to 21.1 mils/yr in the same period, the 0.038" wall thinning measured in 2006 is due to corrosion on the exterior surface of the drywell between 1986 and 1992.

Additionally the 95% confidence level minimum computed drywell shell mean thickness based on 2006 UT measurements within the two trenches is greater by a margin of 250 mils than the minimum required thickness of 0.736" for buckling. Also this margin is significantly greater than the minimum computed margin outside the trenches (64 mils). Individual points within the two trenches met the local thickness acceptance criterion of 0.490"for pressure computed based on ASME Section III, Subsection NE, Class MC Components, Paragraph NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE 3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The individual points also met a local buckling criterion of 0.536" previously established by engineering analysis.

The above UT thickness measurements were supplemented by additional UT measurements taken at 106 points from outside the drywell in the sandbed region, distributed among the ten bays. The locations of these measurements were established in 1992 as being the thinnest local areas based on visual inspection of the exterior surface of the drywell shell before it was coated. The thinnest location measured in 2006 is 0.602" versus 0.618" measured in 1992. The difference between the two measurements does not necessarily mean a wall thinning of 0.016" has taken place since 1992. This is because the 2006 UT data could not be compared directly with the 1992 data due to the difference in UT instruments and measurement technique used in 2006, and the uncertainty associated with precisely locating the 1992 UT points. A review of the 2006 data for the 106 external locations indicated that the measured local thickness is greater than the local acceptance criteria of 0.490" for pressure and 0.536" for local bucking.

As stated above, the 2006 UT data of the locally thinned areas (106 points) could not be correlated directly with the corresponding 1992 UT data. This is largely due to using a more accurate UT instrument and the procedure used to take the measurements, which involved moving the instrument within the locally thinned area in order to locate the minimum thickness in that area. In addition the inner drywell shell surface could be subject to some insignificant corrosion due to water intrusion onto the embedded shell (see discussion below). For these reasons the Oyster Creek ASME Section XI, Subsection IWE Program (B.1.27) will be further enhanced to require UT measurements of the locally thinned areas

in 2008 and periodically during the period of extended operation as explained below.

Drywell Shell above Sand Bed Region:

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

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

As experience increased with each data collection campaign, only grids showing evidence of a change were retained in the inspection program. Additional assurance regarding the adequacy of this inspection plan was obtained by a completely randomized inspection, involving 49 grids that showed that all inspection locations satisfied ASME code requirements. Evaluation of UT measurements taken through 2000 concluded that corrosion is no longer occurring at two (2) elevations **(51'10" and 60'10")**, the 3rd elevation **(50'2")** is undergoing a corrosion rate of 0.6 mils/year, while the 4th elevation **(87'5")** is subject to 1.2 mils/year. The UT measurements **taken in** 2004 confirmed that the corrosion rate continued to decline. The two elevations that previously exhibited no increase in corrosion **continued to show no additional corrosion.** The rate of corrosion for the 3rd elevation decreased from 0.6 mils/year to 0.4 mils/year. The rate of corrosion for the 4th elevation decreased from 1.2 mils/year to 0.75 mils/year. After each UT examination campaign, an engineering analysis was performed to ensure the required minimum thickness is provided through the period of extended operation. Thus corrosion of the drywell shell is considered a TLAA further described in Section 4.7.2.

During the 2006 refueling outage (1R21), UT thickness measurements were taken at the 4 elevations discussed above in accordance with the Oyster Creek ASME Section XI, Subsection IWE aging management program. The results of the UT thickness measurements indicated that no observable corrosion is occurring

at elevations 51' 10" and 60' 10". A single location (Bay 15 –23L) of the 3rd elevation (50 '2") continues to experience minor corrosion at a rate of 0.66 mils/yr. The corrosion rate for the 4th elevation (87' 5") is now statistically insignificant and this elevation can be considered as no longer undergoing observable corrosion.

In addition UT measurements were taken on 2 locations (bay #15 and bay #17) at elevation 23' 6" where the circumferential weld joins the bottom spherical plates and the middle spherical plates. This weld joins plates that are 1.154" thick to the plates that are 0.770" thick. These two bays were selected because they are among those that have historically experienced the most corrosion in the sandbed region. At each location 49 UTs were taken above the weld on the 0.770" thick plate and 49 UTs were taken below the weld on the 1.154" thick plate. The minimum average thickness measured on the 0.770" thick plate is 0.766" and 1.160" on the 1.154" thick plate. The loss of material of 0.004" (0.770" – 0.766") in the 0.770" thick plate is insignificant and is bounded by corrosion experienced in other areas of the drywell above the sandbed region. The thicker plate (1.154") appears not to have experienced observable corrosion.

The minimum measured local thickness on the 0.770" thick plate is 0.628" and on the 1.154" thick plate is 0.867". The minimum required general thickness to satisfy ASME Code stress requirements is 0.541" for the 0.770" thick plate and 0.736" for the 1.154" thick plate. Thus, the minimum margin at these locations is 225 mils (0.766 –0.541). The minimum required local thickness to satisfy ASME Code stress requirements is 0.490" for 1.154" thick plate and 0.360" for the 0.770" thick plate. The minimum local thickness margin is 268 mils (0.628-0.360).

UT measurements were also taken on 2 locations (bay #15 and bay #19) at elevation 71' 6" where the circumferential weld joins the transition plates (referred to as the knuckle plates) between the cylinder and the sphere. This weld joins the knuckle plates, which are 2.625" thick to the cylinder plates, which are 0.640" thick. These two bays were selected because they also have historically experienced the most corrosion in the sandbed region. At each location 49 UTs were taken above the weld on the 0.640" thick plate and 49 UTs were taken below the weld on the 2.625" thick plate. The minimum measured average thickness on the 0.640" thick plate is 0.624" and 2.530" on the 2.625" thick plate. The loss of material of 0.016" (0.640" – 0.624") in the 0.640" thick plate is insignificant and is bounded by corrosion experienced in other areas of the drywell above the sandbed region. The minimum measured average thickness of 0.624" meets the minimum thickness of 0.452" required to satisfy ASME stress requirements with a margin of 172 mils. The minimum measured local thickness on the 0.640" thick plate of 0.449" meets the minimum thickness of 0.300" required to satisfy ASME local stress requirements with a margin of 149 mils.

For the 2.625" plate, the minimum measured average thickness of 2.530" meets the minimum thickness of 2.260" required to satisfy ASME stress requirements with a margin of 270 mils. The loss of material of 0.095" (2.625-2.530) appears to be greater than other periodically monitored locations in the upper regions of the drywell. However the loss of material could be a result of other factors such as a variation in the original nominal plate thickness, and removal of the material during joint preparation for welding and not entirely due to corrosion. Even if the loss of material is attributed entirely to corrosion, the available thickness margin of 270 mils is adequate to ensure that the intended function of the drywell is not impacted before the next inspection planned for 2010 as discussed below. The minimum measured local thickness is 2.428", which is also greater than the minimum required general thickness of 2.260".

Since the 2006 readings are the first UT thickness measurements taken at plate transition at elevation 23'6" and 71'6", a corrosion rate specific to these areas is not established. AmerGen has committed to take UT measurements in 2010 in these areas to confirm that corrosion is bounded by areas of the upper drywell that are monitored periodically. If corrosion in these locations is greater than areas monitored in the upper drywell, UT inspections of the areas will be performed on a frequency of every other refueling outage (Commitment 27.10, 27.11 in AmerGen Letter No. 2130-06-20358 dated July 7, 2006).

Inner Drywell Shell in the Embedded Region

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

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

During the preparation of a response to NRC question AMR-164 in April 2006 during the Aging Management Review Audit, an internal memo was identified that indicated the intermittent presence of water in the two trenches inside the drywell. This was not an expected condition. That memo, dated January 3, 1995 was referenced in a 1996 Structural Monitoring Walkdown Report but was not entered into the Corrective Action Process such that it could be considered as Operating Experience input to the Aging Management Program reviews.

Based on activities performed under the Structures Monitoring Program and IWE Inspection program, and the reviews performed in support of the License Renewal Application, the water on the drywell floor and potentially inside the trenches was previously considered a temporary outage condition and not an operating environment for the embedded shell. However, in its response to NRC Aging Management Review Audit question AMR-164, AmerGen committed to inspect the condition of the drywell interior shell in the trench areas and to evaluate any identified degradation prior to entering the period of extended operation (Commitment 27.5 in AmerGen Letter No. 2130-06-20358 dated July 7, 2006). The results of these inspections and associated corrective actions are described below.

During the October 2006 refueling outage, the filler material from the two trenches was removed to allow inspection of the shell in accordance with commitment #27.5. Upon removal of the filler material, approximately 5" of standing water was discovered in the trench located in bay #5. The trench area in bay #17 was damp; but no standing water was observed. Investigations concluded that the likely source of water was a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough, or condensation within the drywell that either fell to the floor or washed down the inside of the drywell shell to the concrete floor. Water samples taken from the trench in bay #5 were tested and determined to be non-aggressive with pH (8.40 – 10.21), chlorides (13.6 – 14.6 ppm), and sulfates (228 – 230 ppm). The joint between the concrete floor and the drywell shell had not been sealed to prevent water from coming in contact with the inner drywell shell. The degraded trough drainage system and the unsealed gap between the concrete slab/curb and the interior surface of the drywell shell was first discovered during this October 2006 refueling outage. This condition was entered into the Corrective Action Process (IR 546049). The following corrective actions were taken during the October 2006 refueling outage.

- Walkdowns, drawing reviews, tracer testing and chemistry samples were performed to identify the potential sources of water in the trenches.
- Standing water was removed from trench in bay #5 to allow visual inspection and UT examination of the drywell shell.

- **An engineering evaluation was performed by a structural engineer, reviewed by an industry corrosion expert, and an independent third-party expert to determine the impact of the as-found water on the continued integrity of the drywell.**
- **Field repairs/modifications were implemented to mitigate/minimize future water intrusion into the area between the shell and the concrete floor. These repairs/modifications consisted of:**
    - **Repair of the trough concrete in the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell rather than reaching the drywell sump,**
    - **Caulking the interface between the drywell shell and the drywell concrete floor/curb to prevent water from reaching the embedded shell and**
    - **Grouting/caulking the concrete/drywell shell interfaces in the trench areas.**
- **The trench in bay #5 was excavated to uncover an additional 6" of the internal drywell shell surface for inspection and allow UT thickness measurements to be taken in an area of the shell that was embedded by concrete.**
- **Visual inspection of the drywell shell within the trenches was performed.**
- **A total of 584 UT thickness measurements were taken using a 6"x6" template (49 points) within the two trenches. Forty-two (42) additional UT measurements were taken in the newly exposed area in bay #5.**

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

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

An engineering evaluation of the Oyster Creek inner drywell shell condition was prepared by a structural engineer and reviewed by an industry corrosion expert and independent third-party expert to determine the impact of the as-found water on the continued

integrity of the drywell shell. The evaluation utilized water chemical analysis, visual inspections and UT examinations. It concluded that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact and significant corrosion of the drywell shell would not be expected as long as this benign environment is maintained. Therefore, since the concrete environment complies with the EPRI concrete structure guidelines, corrosion would not be considered significant within the Oyster Creek drywell and the water could remain in contact with the interior drywell shell indefinitely without having long term adverse effects.

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

- **The existing water in contact with the drywell shell has been in contact with the adjacent concrete. The concrete is alkaline which increases the pH of the water and, in turn, inhibits corrosion. This high pH water contains levels of impurities that are significantly below the EPRI embedded steel guidelines action level recommendations.**
- **Any new water (such as reactor coolant) entering the concrete-to-shell interface (now minimized by repairs/modifications implemented during this outage) will also increase in pH due to its migration through and contact with the concrete creating a non-aggressive, alkaline environment.**
- **Minimal corrosion of the wetted inner drywell steel surface in contact with the concrete is only expected to occur during outages since the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant since the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also, repairs/modifications implemented during the 2006 outage will further minimize exposure of the drywell shell to oxygen.**

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

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

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

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

- **UT thickness measurements will be taken from outside the drywell in the sandbed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.**
- **Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sandbed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified.**
- **Perform visual inspection of the drywell shell inside the trench in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.**
- **Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor/curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.**

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

The corrective actions taken as discussed above and the continued monitoring of the drywell for loss **of** material through **the enhanced** ASME Section XI, Subsection IWE **program**, the Protective Coating Monitoring and Maintenance Program, and 10 CFR Part 50, Appendix J provide reasonable assurance that loss of material in inaccessible areas of the drywell will be detected prior to **the** loss of an intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE **program**, the Protective Coating Monitoring and Maintenance, and 10 CFR Part 50 Appendix J programs are described in Appendix B.

5. Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

   Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.5 of this standard review plan.

   This is applicable only to PWR and BWR prestressed concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

6. Cumulative Fatigue Damage

   If included in the current licensing basis, fatigue analyses of containment steel liner plates and steel containment shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header and downcomers are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.6 of the standard review plan.

   At Oyster Creek, cumulative fatigue damage of the primary containment penetration sleeves, penetration bellows, suppression chamber (torus), vent header, downcomers, vent line bellows, main steam expansion joints inside the drywell, and containment vacuum breakers system piping, piping components, and expansion joints is a TLAA as defined in 10 CFR 54.3. The TLAA is evaluated in accordance with 10 CFR 54.21 (c). Evaluation of this TLAA is discussed in Section 4.6

7. Cracking due to Cyclic Loading and Stress Corrosion Cracking

Cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC could occur in all types of PWR and BWR containments. Cracking could also occur in vent line bellows, vent headers and downcomers due to SCC for BWR containments. A visual VT-3 examination would not detect such cracks. Moreover, stress corrosion cracking is a concern for dissimilar metal welds. The GALL report recommends further evaluation of the inspection methods implemented to detect these aging effects.

At Oyster Creek, cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading is considered metal fatigue and is addressed as a TLAA in Section 4.6.

Stress corrosion cracking (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 will eliminate 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 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% by volume during normal operation. The normal operating average temperature inside the drywell is less than 139°F and the relative humidity range is 20-40%. The reactor building normal operating temperature range is 65°F - 92°F; except in the trunion room where the temperature can reach 140°F. The relative humidity is 100% 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 did not identify cracking of the components and primary containment leakage has not been identified as a concern. Therefore the existing 10 CFR Part 50 Appendix J leak testing and ASME Section XI, Subsection IWE, are adequate to detect cracking. Observed conditions that have the potential for impacting 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 Appendix B.

8. Scaling, Cracking, and Spalling due to Freeze-Thaw; and Expansion and Cracking due to Reaction with Aggregate

   Scaling, cracking, and spalling due to freeze-thaw could occur in PWR and BWR concrete containments; and expansion and cracking due to reaction with aggregate could occur in concrete elements of PWR and BWR concrete and steel containments. Further evaluation is not necessary if stated conditions are satisfied for inaccessible areas

   This is applicable only to PWR and BWR concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

3.5.2.2.2 Class I Structures

1. Aging of Structures Not Covered by Structures Monitoring Program

   The GALL report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1-3, 5, 7-9 structures; (2) scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1-5, 7-9 structures; (3) expansion and cracking due to reaction with aggregates for Groups 1-5, 7-9 structures; (4) cracking, spalling, loss of bond, and loss of material due to general, pitting and crevice corrosion of embedded steel for Groups 1-5, 7-9 structures; (5) cracks and distortion due to increase in component stress level from settlement for Groups 1-3, 5, 7-9 structures; (6) reduction of foundation strength due to erosion of porous concrete subfoundation for Groups 1-3, 5-9 structures; (7) loss of material due to general, pitting and crevice corrosion of structural steel components for Groups 1-5, 7-8 structures; (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1-5; and (9) cracking due to SCC and loss of material due to crevice corrosion of stainless steel liner for Groups 7 and 8 structures. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

   Technical details of the aging management issue are presented in Subsection 3.5.2.2.1.2 for items (5) and (6) and Subsection 3.5.2.2.1.3 for item (8).

   Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas for Groups 1-3, 5, 7-9 structures; and expansion and cracking due to reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 1-5, 7-9 structures. The GALL report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL report cannot be satisfied.

   At Oyster Creek, the Structures Monitoring Program (B.1.31) is used to manage aging affects applicable to Groups 2,3, 4, and 8-9 structures as

discussed below. The GALL structures Group 1 and Group 7 do not exist for Oyster Creek. Group 5, "Fuel Storage Facility", is included with Group 2 structures.

(1) Loss of material and cracking due to repeated freeze-thaw for Groups 2,3, and 8-9 structures are managed through the Structures Monitoring Program and thus a further evaluation is not necessary.

(2) Scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 2, 4, and 8-9 structures are not applicable. The structures are not exposed to aggressive environment or water – flowing environment. Group 3 structures are also not exposed to aggressive, or water – flowing environments except for the Fire Water Pumphouses (fresh water pumphouse only), and the service water seal well (included with Miscellaneous Yard structures). The structures are within the scope of Structures Monitoring Program and inspected as described in Appendix B.

(3) Cracking due to reaction with aggregates for Groups 2-4, and 8-9 structures is monitored through Structures Monitoring Program, and thus a further evaluation is not necessary.

(4) Loss of material, cracking, and change in material properties due to corrosion of embedded steel for Groups 2-4, and 8-9 structures are monitored through the Structures Monitoring Program and thus a further evaluation is not required.

(5) The Structures Monitoring Program will be used to manage Cracks and distortion due to increase in component stress level from settlement for Groups 2-4, and 8-9 structures. However this aging mechanism is insignificant for Oyster Creek structures because the structures are founded on highly dense soil. Evaluation of soil explorations, during the original construction, predicted no more than 1" settlement for Class I structures. Observed settlement of the reactor building has ranged from 0.33" – 0.75" and was essentially complete soon after construction. Thus a settlement monitoring program is not required; nor is a de-watering system relied upon in the CLB to control settlement.

(6) Reduction of foundation strength due to erosion of porous concrete sub foundation for Groups 2-4, and 8-9 structures. This aging effect and mechanism is not applicable to Oyster Creek. The Oyster Creek design does not include porous concrete into the sub foundation of Groups 2-4 and 8-9 structures.

(7) Loss of material due to general, pitting and crevice corrosion of structural steel components for Groups 2-4, and 9 structures is monitored through the Structures Monitoring Program, and thus a further evaluation is not required.

(8) For loss of strength and modulus of concrete structures due to elevated temperatures for Groups 2-5, GALL recommends a Plant Specific AMP and further evaluation if the general temperature is greater than 150°F or if the local temperature is greater than 200°F. For Oyster Creek, the Structures Monitoring Program is used to manage cracking of concrete structures exposed to elevated temperatures.

Concrete temperature limits specified in the GALL report are exceeded only in a section of the reactor building (Group 2) drywell shield wall that encloses the containment drywell head. Thermocouples mounted on the head, in the general area of the shield wall, indicated a maximum temperature of 285°F. Engineering analysis predicted that the average temperature through the 5' thick concrete wall could be in the range of 180°F-215°F; considering a worst case thermal environment inside the containment of 340°F. As a result, an investigation was initiated to evaluate the impact of the elevated temperature on the structural integrity of the shield wall. The initial inspection of the shield wall identified concrete cracking in the area that is subject to high temperature. A map of the cracked area that includes crack length and width was developed for future monitoring.

Subsequently, an engineering evaluation was conducted to assess the impact of the elevated temperature on the drywell shield wall. For this purpose, a finite element model was created considering geometry of the shield wall and structural elements connected to it. The analysis was based on a temperature of 285°F and a reduced concrete compressive strength that accounts for temperature-induced reduction. The results concluded that concrete and rebar stress limits are in accordance with ACI 349 criteria with an adequate safety margin. NRC staff review found the analysis acceptable and concluded that the wall is capable of performing its intended function. The Staff also recommended condition monitoring of the drywell shield wall to ensure its continued function. The wall has been included in the scope of the Structures Monitoring Program and inspected periodically to ensure its continued function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Structures Monitoring Program is described in Appendix B.

(9) Cracking due to SCC and loss of material due to crevice corrosion of stainless steel liner are not in the scope of Structures Monitoring Program. Instead, the aging effects are managed through the Water Chemistry Program (B.1.2) and monitoring of spent fuel pool water level, consistent with the GALL AMP. Therefore a further evaluation is not necessary.

At Oyster Creek, the Structures Monitoring Program (B.1.31) is used to manage concrete aging effects due to various aging mechanisms.

The program requires periodic inspection of accessible areas and inspection of inaccessible areas when they become accessible. The below-grade concrete structures are inspected, when excavated for any reason. In addition, the criteria defined in the GALL report is satisfied as discussed below.

Oyster Creek is located in a moderate to severe weathering conditions. As a result loss of material (spalling, scaling) and cracking due to free-thaw is applicable to Groups 2-3 and 8-9 structures. However these concrete structures are designed and constructed in accordance with ACI 318 and provide for low permeability and adequate air entrainment (4% - 6%) such that the concrete is not susceptible to freeze-thaw aging effects. Inspections of accessible areas have identified cracks on the exterior walls of the reactor building. The cracks have been attributed to a combination of early concrete shrinkage, expansion, and contraction due to temperature variation. Spalling and scaling of any significance have not been observed.

At Oyster Creek, expansion and cracking due to reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 2-4, and 8-9 structures.

At Oyster Creek, concrete specifications require Type II; low alkali cement shall be used. Alkali content is limited to 0.6 per cent total alkali unless tests performed in accordance with ASTM C295 and C227 demonstrate no potential for alkali reactivity for the aggregate.

Inspection activities in accordance with the Structures Monitoring Program described above, in conjunction with concrete quality that meets ACI 318, ASTM 295, and ASTM C227 standards, provide reasonable assurance that the below-grade concrete will perform its intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Structures Monitoring Program is described in Appendix B.

2. Aging Management of Inaccessible Areas

Cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas. The GALL report recommends further evaluation to manage these aging effects in inaccessible areas of Groups 1-3, 5, 7-9 structures.

Recent Oyster Creek groundwater analysis results (pH: 5.6 – 6.4, chlorides: 3 - 138 ppm, and sulfates: 7 – 73 ppm) have shown that the groundwater at Oyster Creek is not aggressive for Groups 2-3, 8-9 structures. Therefore further evaluation of below-grade inaccessible

concrete areas for Groups 2, and 8-9 structures is not required. Similarly inaccessible areas of Group 3 structures are not exposed to aggressive environment except for Fire Water Pumphouses (fresh water pumphouse only). Further evaluation of group 3 structures, other than fresh water pumphouse is not required.

The fresh water pumphouse reinforced concrete is subject to slightly aggressive water from the Fire Pond Dam (pH: 4.8, chlorides = 12 ppm, and sulfates = 6 ppm). Inaccessible areas will be inspected if excavated for any reason, or if observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

The Structures Monitoring Program will be enhanced to include periodic groundwater monitoring in order to demonstrate that the below grade environment remains non-aggressive. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Structures Monitoring Program is described in Appendix B.

3.5.2.2.3 Component Supports

1. Aging of Supports Not Covered by Structures Monitoring Program

The GALL report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports; (2) loss of material due to environmental corrosion, for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

At Oyster Creek, (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports, (2) loss of material for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports are covered under the Structures Monitoring Program.

The Structures Monitoring Program will be used to manage loss of material on exterior surfaces of piping, piping components, HVAC components and ductwork, tanks, and other mechanical components located in outdoor air environment. The program will also be used to manage loss of material and change in material properties of exterior surfaces of mechanical system components in indoor air environment as described in Appendix (B.1.31) and as evaluated in sections 3.1, 3.2, 3.3, and 3.4 of this application.

Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the Corrective

Action Process. The Structures Monitoring Program is described in Appendix B.

2. Cumulative Fatigue Damage Due To Cyclic Loading

   Fatigue of support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports is a TLAA as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.3 of the standard review plan.

   At Oyster Creek, there are no fatigue analyses applicable to Groups B1.1, and B1.2 component supports in the CLB. Therefore, cumulative fatigue damage for Groups B1.1 and B1.2 component supports is not a TLAA as defined in 10 CFR 54.3.

   The Oyster Creek CLB includes fatigue analysis for certain Group B1.3, ASME Class MC component supports. For these supports (Torus support columns and sway braces), cumulative fatigue damage is a TLAA evaluated in accordance with 10 CFR 54.21(c) in Section 4.6.1.

3.5.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Primary Containment, Structures, and Component Supports components:

- Section 4.6, Primary Containment, Attached Piping and Components
- Section 4.7.1, Reactor Building Crane, Turbine Building Crane, Heater Bay Crane Load Cycles
- Section 4.7.2, Drywell Corrosion
- Section 4.7.3, Equipment Pool and Reactor Cavity Walls Rebar Corrosion

3.5.3 CONCLUSION

The Primary Containment, Structures, Component Supports, and Piping and Component Insulation components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Primary Containment, Structures, Component Supports, and Piping and Component Insulation components are identified in the summaries in Section 3.5.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Primary Containment, Structures, and Component Supports components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Type	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-13	BWR/ PWR	Steel elements: liner plate, containment shell downcomers, drywell support skirt, ECCS suction header	Loss of material due to general, pitting and crevice corrosion in accessible and inaccessible areas	Containment ISI and Containment leak rate test	Yes, if corrosion is significant for inaccessible areas	Consistent with NUREG-1801 with exceptions. The ASME Section XI, Subsection IWE, B.1.27, and 10 CFR Part 50, Appendix J, B.1.29 will be used to manage loss of material for steel elements of the primary containment. In addition loss of material of the drywell is considered a TLAA and evaluated in accordance with 10CFR54.21(c). The ASME Section XI, Subsection IWE, B.1.27, 10 CFR Part 50, Appendix J, B.1.29, will also be used to manage loss of material of the containment vacuum breakers system piping and piping components. Exceptions apply to the NUREG-1801 ASME Section XI, Subsection IWE Loss of material due to corrosion, in the sand bed region and on the exterior surfaces of the upper region of drywell, was identified as a potential concern in early 1980's. As a result, the sand was removed from the sand bed region and a protective coating was applied to the drywell exterior surfaces in that region. The upper regions of the drywell shell are examined periodically by ultrasonic (UT) measurements and evaluated to ensure that the actual thickness meets ASME requirements. **Loss of material due to corrosion of inaccessible inner drywell shell surface has been evaluated and determined to be insignificant; but will be managed in accordance with the enhanced Oyster Creek ASME Section XI, Subsection IWE, B.1.27, and 10 CFR Part 50, Appendix J, B.1.29 during the period of extended operation.** See Subsection 3.5.2.2.1.4.

Table 3.5.2.1.1
Primary Containment
Summary of Aging Management Evaluation

Table 3.5.2.1.1 Primary Containment

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Drywell Shell	Pressure Boundary	Carbon and low alloy steel	Concrete (Internal w/water)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10
					TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
			Water (Internal)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10
					TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
	Structural Support	Carbon and low alloy steel	Concrete (Internal w/water)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10

Table 3.5.2.1.1 Primary Containment (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Drywell Shell	Structural Support	Carbon and low alloy steel	Concrete (Internal w/water)	Loss of Material	TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
			Water (Internal)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10
					TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
Moisture Barrier	Leakage Boundary	Elastomer	Containment Atmosphere	Change in Material Properties	ASME Section XI, Subsection IWE (B.1.27)	II.B4-7 (C-18)	3.5.1-6	B, 11, 12
			Treated Water	Change in Material Properties	ASME Section XI, Subsection IWE (B.1.27)			G, 11,12
Reinforced Concrete Floor Slab (fill slab)	Enclosure Protection	Concrete	Treated Water (Submerged)	Change in Material Properties	Structures Monitoring Program (B.1.31)			G, 13
				Cracking	Structures Monitoring Program (B.1.31)			G, 13
				Loss of Material	Structures Monitoring Program (B.1.31)			G, 13
	Structural Support	Concrete	Treated Water (Submerged)	Change in Material Properties	Structures Monitoring Program (B.1.31)			G, 13

Table 3.5.2.1.1 Primary Containment (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Reinforced Concrete Floor Slab (fill slab)	Structural Support	Concrete	Treated Water (Submerged)	Cracking	Structures Monitoring Program (B.1.31)			G, 13
				Loss of Material	Structures Monitoring Program (B.1.31)			G, 13

Notes	Definition of Note
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1. The biological shield wall high density concrete is unreinforced, encased in steel plates (biological shield wall liner plate) and is inaccessible.
2. ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J are the applicable aging management programs for Class MC pressure retaining bolting.
3. The Aging effects and Aging Management Program identified for this material/environment combination are consistent with industry guidance.
4. Loss of material due to corrosion is a TLAA for the drywell shell in Oyster Creek CLB
5. Protective coatings applied to the external surfaces of the drywell where the sand is removed (sand pocket region) has been credited for mitigating loss of material due to corrosion in CLB.
6. Concrete in contact with the embedded containment shell meets the requirements of ACI 318 and the guidance of 201.R.
7. Reduction of strength and modulus due to elevated temperature is not an aging effect requiring management. See further evaluation in Section 3.5.2.2.1.3
8. Structures Monitoring Program is the applicable aging management program for this component
9. Primary containment leakage is controlled in accordance with Oyster Creek Technical Specifications.
10. **Water environment for the drywell shell and the reinforced concrete slab (fill slab) was identified during 2006 in two trenches inside the drywell concrete floor. The source of water is most likely from leakage of treated water from plant equipment inside the drywell. Chemical tests of water**

samples in contact with concrete and the drywell shell indicate that the water is not aggressive (pH = 8.40 -10.21), (Chloride =13.6 - 14.6 ppm), and (Sulfate = 228 - 230 ppm).

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

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

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

A.1.27 ASME SECTION XI, SUBSECTION IWE

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic inspection of primary containment surfaces and components, including integral attachments, and containment vacuum breakers system piping and components for loss of material, loss of sealing, and loss of preload.

Examination methods include visual and volumetric testing as required by the Code. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action process. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied to bolting.

In accordance with commitments made during the Oyster Creek license renewal application review process, the program will be enhanced to include:

1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection to provide early confirmation that corrosion has been arrested. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:
   - Perform additional UT measurements to confirm the readings.
   - Notify NRC within 48 hours of confirmation of the identified condition.
   - Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected.
   - Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity.
   - Perform operability determination and justification for operation until next inspection.

   These actions will be completed prior to restart from the associated outage.

2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:

- 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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.
- The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:

  - Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
  - UTs of the upper drywell region consistent with the existing program
  - UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred
  - UT results will be evaluated per the existing program

  Any degraded coating or moisture barrier will be repaired

4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.

5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus

bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.

7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.

9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).

10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

12. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected.

13. The reactor cavity seal leakage concrete trough drain will be verified to be clear from blockage once per refueling cycle.

14. **UT thickness measurements will be taken from outside the drywell in the sandbed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The**

locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

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

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

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

A.5 License Renewal Commitment List

The following table identifies modifications made to license renewal commitment # 27, for the ASME Section XI, Subsection IWE Primary Containment Inspection Program, being made in this supplemental response. Previous updates to commitment # 27 were most recently made in AmerGen letter 2130-06-20358, dated July 7, 2006. The new information is displayed in **bold** font.

Any other actions discussed in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments.

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: 1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:	A.1.27	Prior to the period of extended operation Prior to the period of extended operation, and then two refueling outages after that. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals	Section B.1.27

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	• Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.			
	2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.		Refueling outages prior to and during the period of extended operation	
	3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage.		Periodically	
	• The sand bed region drains will be monitored daily during refueling		Daily during refueling outages	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage. • The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage: • Inspection of the drywell shell coating and moisture barrier (seal) in		Quarterly during non-outage periods	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program Any degraded coating or moisture barrier will be repaired. 4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.		Prior to the period of extended operation and every ten years during the period of extended operation	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.		Prior to the period of extended operation	
	6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to and during the period of extended operation	
	7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the		Every other refueling outage prior to and during the period of	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	same locations as are currently measured.		extended operation	
	8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.			
	9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).		Prior to the period of extended operation	
	10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is		Prior to the period of extended operation and two refueling outages later	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).			
	11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later	
	12. When the sand bed region drywell shell coating inspection is performed (commitment 27, item 4), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.		Coincident with the sand bed region drywell shell coating inspection	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	13. The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.		Once per refueling cycle	
	14. UT thickness measurements will be taken from outside the drywell in the sandbed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.		**During the 2008 refueling outage**	
	15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sandbed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified.		**Starting in 2010, two bays will be inspected per outage, such that the shell will be inspected from all 10 sandbed bays within a 10-year period. See commitment for scope expansion criteria.**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	16. Perform visual inspection of the drywell shell inside the trenches in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.		During the 2008 refueling outage and subsequent outages until trenches are restored to original configuration	
	17. Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor/curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.		In accordance with ASME Section XI, Subsection IWE	

B.1.27 ASME SECTION XI, SUBSECTION IWE

Program Description

The ASME Section XI, Subsection IWE aging management program provides for inspection of primary containment components and the containment vacuum breakers system piping and components. It is implemented through station plans and procedures and covers steel containment shells and their integral attachments; containment hatches and airlocks, seals and gaskets, containment vacuum breakers system piping and components, and pressure retaining bolting. The program includes visual examination and limited surface or volumetric examination, when augmented examination is required, to detect loss of material. The program also provides for managing loss of sealing for seals and gaskets, and loss of preload for pressure retaining bolting. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied. The Oyster Creek program complies with Subsection IWE for steel containments (Class MC) of ASME Section XI, 1992 Edition including 1992 Addenda in accordance with the provisions of 10 CFR 50.55a. Enhancements to the program, which are negotiated with NRC, to provide reasonable assurance that drywell corrosion is adequately managed during the period of extended operation are described below.

NUREG-1801 Consistency

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

Exceptions to NUREG-1801

NUREG-1801 evaluation is based on ASME Section XI, 2001 Edition including 2002 and 2003 Addenda. The current Oyster Creek ASME Section XI, Subsection IWE program plan for the First Ten-Year inspection interval effective from September 9, 1998 through September 9, 2008, approved per 10CFR50.55a, is based on ASME Section XI, 1992 Edition including 1992 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

Enhancements

1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection to provide early confirmation that corrosion has been arrested. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals. The UT measurements will be taken from the

inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:

- Perform additional UT measurements to confirm the readings.
- Notify NRC within 48 hours of confirmation of the identified condition.
- Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected.
- Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity.
- Perform operability determination and justification for operation until next inspection.

These actions will be completed prior to restart from the associated outage.

2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:

   - 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 and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.

   - The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:

   - Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
   - UTs of the upper drywell region consistent with the existing program
   - UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred

- UT results will be evaluated per the existing program
- Any degraded coating or moisture barrier will be repaired

4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage. Inspection of the coating is accomplished through the Protective Coating Monitoring and Maintenance Program (B.1.33)

5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Monitoring and Maintenance Program (B.1.33). The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.

7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.

9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).

10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates in the lower portion of the spherical region of the drywell shell. These

measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at one location using the 6"x6" grid. These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).

12. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected

13. The reactor cavity seal leakage concrete trough drain will be verified to be clear from blockage once per refueling cycle.

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

14. **UT thickness measurements will be taken from outside the drywell in the sandbed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.**
15. **Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sandbed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified.**
16. **Perform visual inspection of the drywell shell inside the trench in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at**

the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

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

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

Operating Experience

ASME Section XI, Subsection IWE as described in Oyster Creek First-10 Year Containment (IWE) Inservice Inspection Program Plan and Basis is effective September 9, 1998 to September 9, 2008. Base line inspection of containment surfaces was completed in 2000 and a second inspection was completed in 2004. The 2004 inspection identified (2) recordable conditions, a loose locknut was identified on a spare drywell penetration and a weld rod was found stuck to the underside of the drywell head. Engineering evaluation concluded the stuck weld rod has no adverse impact on drywell head structural integrity and the loose locknut did not affect the seal of the containment penetration.

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

Similarly the sand bed region also experienced loss of material due to corrosion. Corrosion was attributed to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. As a corrective measure, the sand was removed and a protective coating was applied to the shell to mitigate further corrosion. Subsequent inspections confirmed that corrosion of the shell has been arrested. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program, B.1.33. Refer to program B.1.33 for additional details.

The suppression chamber (Torus) and vent system were originally coated with Carboline Carbo-Zinc 11 paint. The coating is inspected every outage and

repaired, as required, to protect the torus shell and the vent system from corrosion. Refer to program B.1.33 for additional details.

Operating experience review concluded that ASME Section XI, Subsection IWE is effective for managing aging effects of primary containment surfaces.

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

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

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

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

general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin.

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

<u>Inner Drywell Shell in the Embedded Region</u>

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

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

During the October 2006 refueling outage, the filler material from the two trenches was removed to allow inspection of the shell in accordance with commitment #27.5. Upon removal of the filler material, approximately 5" of standing water was discovered in the trench located in bay #5. The trench area in bay #17 was damp; but no standing water was observed. Investigations concluded that the likely source of water was a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough, or condensation within the drywell that either fell to the floor or washed down the inside of the drywell shell to the concrete floor. Water samples taken from the trench in bay #5 were tested and determined to be non-aggressive with pH (8.40 – 10.21), chlorides (13.6 – 14.6 ppm),

and sulfates (228 – 230 ppm). The joint between the concrete floor and the drywell shell had not been sealed to prevent water from coming in contact with the inner drywell shell. The degraded trough drainage system and the unsealed gap between the concrete slab/curb and the interior surface of the drywell shell was first discovered during this October 2006 refueling outage. This condition was entered into the Corrective Action Process (IR 546049). The following corrective actions were taken during the October 2006 refueling outage.

- **Walkdowns, drawing reviews, tracer testing and chemistry samples were performed to identify the potential sources of water in the trenches.**
- **Standing water was removed from trench in bay #5 to allow visual inspection and UT examination of the drywell shell.**
- **An engineering evaluation was performed by a structural engineer, reviewed by an industry corrosion expert, and an independent third-party expert to determine the impact of the as-found water on the continued integrity of the drywell.**
- **Field repairs/modifications were implemented to mitigate/minimize future water intrusion into the area between the shell and the concrete floor. These repairs/modifications consisted of:**
    - **Repair of the trough concrete in the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell rather than reaching the drywell sump,**
    - **Caulking the interface between the drywell shell and the drywell concrete floor/curb to prevent water from reaching the embedded shell and**
    - **Grouting/caulking the concrete/drywell shell interfaces in the trench areas.**
- **The trench in bay #5 was excavated to uncover an additional 6" of the internal drywell shell surface for inspection and allow UT thickness measurements to be taken in an area of the shell that was embedded by concrete.**
- **Visual inspection of the drywell shell within the trenches was performed.**
- **A total of 584 UT thickness measurements were taken using a 6"x6" template (49 points) within the two trenches. Forty-two (42) additional UT measurements were taken in the newly exposed area in bay #5.**

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

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

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

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

- **The existing water in contact with the drywell shell has been in contact with the adjacent concrete. The concrete is alkaline which increases the pH of the water and, in turn, inhibits corrosion. This high pH water contains levels of impurities that are significantly below the EPRI embedded steel guidelines action level recommendations.**
- **Any new water (such as reactor coolant) entering the concrete-to-shell interface (now minimized by repairs/modifications implemented during this outage) will also increase in pH due to its migration through and contact with the concrete creating a non-aggressive, alkaline environment.**
- **Minimal corrosion of the wetted inner drywell steel surface in contact with the concrete is only expected to occur during outages since the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant since the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also, repairs/modifications implemented during the 2006 outage will further minimize exposure of the drywell shell to oxygen.**

Based on the UT measurements taken during the 2006 outage of the newly exposed shell area in Bay 5 that has not been examined since it was encased in concrete during initial construction (pre-1969), it was

determined that the total metal lost based on a current average thickness measurement of 1.113" versus a nominal plate thickness of 1.154" is only 0.041" (total wall loss for both inside and outside of the drywell shell). Although no continuing corrosion is expected, but conservatively assuming that a similar wall loss could occur between now and the end of the period of extended operation, a margin of 336 mils to the 0.736" required wall thickness would exist.

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

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

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

Conclusion

The enhanced ASME Section XI, Subsection IWE aging management program ensures that loss of material, loss of sealing, and loss of preload of primary containment components and the containment vacuum breakers system piping and components are adequately managed so that there is a reasonable assurance their intended function will be maintained consistent with the current licensing basis during the period of extended operation.

B.1.31 STRUCTURES MONITORING PROGRAM

Program Description

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

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

The program relies on periodic visual inspections by qualified personnel to monitor structures and components for applicable aging effects. Specifically, concrete structures are inspected for loss of material, cracking, and a change in material properties. Steel components are inspected for loss of material due to corrosion. Masonry walls are inspected for cracking, and elastomers will be monitored for a change in material properties. Earthen structures associated with water-control structures and the Fire Pond Dam will be inspected for loss of material and loss of form. Component supports will be inspected for loss of material, reduction or loss of isolation function, and reduction in anchor capacity due to local concrete degradation. Exposed surfaces of bolting are monitored for loss of material, due to corrosion, loose nuts, missing bolts, or other indications of loss of preload. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied consistent with the NUREG-1801 bolting integrity program.

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

Inspection frequency is every four (4) years; except for submerged portions of water- control structures, which will be inspected when the structures are dewatered, or on a frequency not to exceed 10 years. The program contains provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process

NUREG-1801 Consistency

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

Exceptions to NUREG-1801

None.

Enhancements

The scope of the program will be increased to add buildings, structural components and commodities that are not in scope of maintenance rule but have been determined to be in the scope of license renewal. These include miscellaneous platforms, flood and secondary containment doors, penetration seals, liner for sumps, structural seals, and anchors and embedment.

The scope of the program will be enhanced to include Station Blackout System Structures, structural components, and phase bus enclosure assemblies. Inspection frequency, inspection methods, and acceptance criteria will be the same as those specified for other structures in scope of the program.

The scope of the program will be increased to include component supports, other than those in scope of ASME XI, Subsection IWF.

The scope of the program will be enhanced to include inspection of external surfaces of Oyster Creek and Forked River Combustion Turbine mechanical components that are not covered by other programs, including exterior surfaces of HVAC duct, damper housings, and HVAC closure bolting. Inspection and acceptance criteria of the exterior surfaces will be the same as those specified for structural steel components and structural bolting.

The program will be enhanced to require removal of piping and component insulation to permit visual inspection of insulated surfaces. Removal of insulation will be on a sampling basis that bounds insulation material type, susceptibility of insulated piping or component material to potential degradations that could result from being in contact with insulation, and system operating temperature.

The program will provide for inspections of, electrical panels and racks, junction boxes, instrument racks and panels, cable trays, offsite power structural components and their foundations, and anchorage.

The program will provide for periodic sampling and testing of ground water and review its chemistry data to confirm that the environment remains non-aggressive for buried reinforced concrete.

The program will provide for periodic inspection of components submerged in salt water (Intake Structure and Canal, Dilution structure) and in the water of the fire pond dam, including trash racks at the Intake Structure and Canal.

The program will require inspection of penetration seals, structural seals, and other elastomers for change in material properties by inspecting the elastomers for cracking and hardening.

The program will require inspection of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF, for reduction or loss of isolation function by inspecting the isolators for cracking and hardening.

The current inspection criteria will be enhanced to add loss of material, due to corrosion for steel components, and change in material properties, due to leaching of calcium hydroxide and aggressive chemical attack for reinforced concrete. Accessible wooden piles and sheeting will be inspected for loss of material and a change in material properties. Concrete foundations for Station Blackout System structures will be inspected for cracking and distortion due to increased stress level from settlement that may result from degradation of the inaccessible wooden piles.

The program will be enhanced to include periodic inspection of the Fire Pond Dam for loss of material and loss of form.

The program will be enhanced to include inspection of Meteorological Tower Structures. Inspection and acceptance criteria will be the same as those specified for other structures in the scope of the program.

The program will be enhanced to include inspection of exterior surfaces of piping components associated with the Radio Communications system, located at the meteorological tower site, for loss of material due to corrosion. Inspection and acceptance criteria will be the same as those structures. Enhancements will be implemented prior to the period of extended operation.

Operating Experience

The review of program documentation, and other plant operating experience before the program was implemented, identified cracking of reinforced of exterior walls of the reactor building, drywell shield wall above elevation 95', and the spent fuel pool support beam. Cracking of the reactor building exterior walls was generally minor and attributed to early shrinkage of concrete and temperature changes. Engineering evaluation concluded that the structural integrity of the walls is unaffected by the cracks. Repairs to areas of concern were made to prevent water intrusion and corrosion of concrete rebar. The cracks and repaired areas are monitored under the program to detect any changes that would require further evaluation and corrective action.

Cracking of the drywell shield wall was attributed to high temperature in the upper elevation of the containment drywell. Engineering analysis concluded that stresses are well below allowable limits taking into consideration the existing cracked condition. The shield wall cracking was addressed in NRC SEP review of the plant under Topic III-7B. The cracks have been mapped and inspected periodically under the program. Recent inspections identified no significant change in the cracked area.

Cracking of the spent fuel storage pool concrete support beams was identified in mid-1980. Subsequently crack monitors were installed to monitor crack growth and an engineering evaluation was performed. Based on the evaluation results and additional non-destructive testing to determine the depth of the cracks, it was concluded that the beams would perform their intended function, and that continued monitoring with crack monitors is not required. The cracks are examined periodically under the program and have shown little change.

Inspection of the intake canal, performed in 2001, identified cracks and fissures, voids, holes, and localized washout of coatings that protect embankment slopes from erosion. The degradations were evaluated and determined not to impact the intended function of the intake canal (UHS). However the inspector recommended repair of the degradations to prevent further deterioration. A project to repair the canal banks has been initiated.

Inspections conducted in 2002, concluded that degradations discussed above have not become worse and remains essentially the same as identified in previous inspections. In addition minor cracking, rust stains, water stains, localized exposed rebars and rebar corrosion, and damage to siding were observed. The degradations were evaluated and determined not to have an impact on the structural integrity of affected structures. Operating experience review concluded that the program is effective for managing aging effects of structures, structural components, and water-control structures.

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

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

During the October 2006 refueling outage, the filler material from the two trenches was removed to allow inspection of the shell in accordance with license renewal commitment #27.5 (AmerGen Letter No. 2130-06-20358 dated July 7, 2006). Upon removal of the filler material, approximately 5" of the standing water was discovered in the trench located in bay #5. The trench area in bay #17 was damp, but no standing water was observed. Water samples taken from the bay #5 trench were tested and determined to be non-aggressive with pH (8.40 – 10.21), chlorides (13.6 – 14.6 ppm), and sulfates (228 – 230 ppm). The high pH in water is typical of the concrete alkaline environment. This condition was entered into the Corrective Action Process (IR 546049).

As a result of identifying standing water inside the bay #5 trench and dampness in the bay #17 trench, investigations were conducted to identify the entry point of water into the concrete below the floor slab level. The investigations concluded that the likely entry point for the water was a deteriorated connection in the Sub-Pile Room (room within the reactor pedestal, below the CRD housings) drainage trough drainpipes, at a void in the bottom of Sub-Pile Room drainage trough, and at the unsealed gap at the elevation 10'-3" concrete slab curb and the interior surface of the drywell shell. Field repairs/modifications were implemented to mitigate/minimize future water intrusion into the area between the shell and the concrete floor slab. Engineering evaluations were conducted to assess the impact of the water environment on the structural integrity of the drywell shell and reinforced concrete. Evaluation of the drywell shell is discussed in detail in LRA Section 3.5.2.2.1.4 and in Appendix B.1.27. Evaluation of the reinforced concrete fill slab is discussed below.

Visual inspection of the reinforced concrete slab was conducted in accordance with this program (Structures Monitoring Program, B.1.31) during the October 2006 refueling outage. The structural engineer who conducted the inspection noted that the concrete floor slab outside the reactor pedestal is in good condition with no visible evidence of rebar corrosion (cracking, spalling), or other structural defects. The edge of the concrete curb where it meets the drywell shell was uneven. Some concrete had chipped off due to sharp edges. The loss of material is not a structural concern but the gap where chipped concrete was observed could be a possible path for water intrusion (this area was later sealed). Inspection of the reactor pedestal wall and the floor slab of the Sub-Pile Room were observed to be in good condition.

In summary, engineering evaluation of the inspection results concluded that water intrusion into the concrete has no impact on the structural integrity of the slab. The observed condition of the concrete is typical of concrete in other areas of the plant. There is no evidence of rebar corrosion, significant cracking, or other concrete degradations. Such degradations would not be expected due to the high pH, and the low chlorides and sulfates content of the concrete/water environment.

Conclusion

The Structures Monitoring Program was developed to implement the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program relies on periodic visual inspections to monitor the condition of structures and structural components. Inspection frequency is every four (4) years (except for water-control structures) with provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. Submerged portions of water-control structures will be inspected when dewatered or on a frequency not to exceed ten (10) years.

The scope of the program will be enhanced to include all structures, and component supports not covered by other programs, the Fire Pond Dam, and exterior surfaces of mechanical components in the scope of license renewal that are not covered by other programs. Inspection criteria will also be enhanced to provide reasonable assurance that the aging effects are adequately managed so that the intended functions of structures and components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Monitored Elevation	Location	Minimum Required Thickness, inches [5]	Average Measured Thickness [1,2,4], inches												Projected Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	2006	
Elevation 50' 2"		0.541"													
	Bay 5–D12					0.743 0.745 0.746	0.742 0.745 0.748	0.747 0.747		0.741	0.748	0.741	0.743	**0.747**	No **Observable** Ongoing Corrosion
	Bay 5– 5H					0.761 0.761	0.755 0.758 0.760	0.759 0.759		0.754	0.757	0.754	0.756	**0.760**	**No Observable Ongoing Corrosion**
	Bay 5– 5L					0.706 0.703	0.703 0.705 0.706	0.703 **0.702** **(7)**		0.702	0.705	0.706	0.701	**0.705**	No **Observable** Ongoing Corrosion
	Bay 13–31H					0.762 0.779	0.760 0.758 0.765	0.765 0.763		0.759	0.766	0.762	0.758	**0.762**	No **Observable** Ongoing Corrosion
	Bay 13–31L					0.687 0.684	0.689 0.678 0.688	0.685 0.688		0.683	0.690	0.682	0.693	**0.678**	No **Observable** Ongoing Corrosion
	Bay 15–23H					0.758 0.764	0.762 0.762 0.765	0.767 0.763		0.758	0.760	0.758	0.757	**0.749**	**0.720**
	Bay 15–23L					0.726 0.728	0.726 0.729 0.725	0.726 0.724		0.728	0.724	0.729	0.727		

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Monitored Elevation	Location	Minimum Required Thickness, inches [5]	Average Measured Thickness [1,2,4], inches												Projected Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	2006	
Elevation 51' 10"		**0.518" (6)**													
	Bay 13–32H					0.716	0.715 0.715 0.720	0.717 0.717		0.714	0.715	0.715	0.713	**0.715**	No **Observable** Ongoing Corrosion
	Bay 13–32L					0.686	0.683 0.683 0.682	0.683 0.676		0.680	0.684	0.679	0.687	**0.685**	No **Observable** Ongoing Corrosion
Elevation 60' 10"		0.518"													
	Bay 1–50-22								0.693	0.711	0.693	0.689	**0.693 (8)**	**0.691**	No **Observable** Ongoing Corrosion
Elevation 87' 5"		0.452"													
	Bay 9– 20		0.619	0.622 0.620	0.619	0.620	0.614 0.612	0.629 0.614		0.613	0.613	0.604	0.612	**0.617**	**No Observable Ongoing Corrosion**
	Bay 13–28		0.643	0.641 0.642	0.645	0.643	0.635 0.629	0.641 0.637		0.640	0.636	0.635	0.640	**0.642**	No **Observable** Ongoing Corrosion
	Bay 15–31		0.638	0.636 0.636	0.638	0.642	0.628 0.627	0.631 0.630		0.633	0.632	0.628	0.630	**0.633**	**No Observable Ongoing Corrosion**

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Notes:

1. The average thickness is based on 49 Ultrasonic Testing (UT) measurements performed at each location
2. Multiple inspections were performed in the years 1988, 1990, 1991, and 1992.
3. The 1993 elevation 60' 10" Bay 5-22 inspection was performed on January 6, 1993. All other locations were inspected in December 1992.
4. Accuracy of Ultrasonic Testing Equipment is plus or minus 0.010 inches.
5. Reference SE-000243-002.
6. **Minimum required thickness for elevation 51' 10" was inadvertently listed as 0.541" in the original RAI response. The correct value is 0.518". There is no impact on the analysis, as this was a transcription error between the calculation and Table 1.**
7. **This 1992 value for Location Bay 5-5L was inadvertently reported as 0.707" (instead of 0.702") in the original RAI response. There is no impact on the analysis, as this was a transcription error between the calculation and Table 1.**
8. **The 2004 value for Location Bay 1-50-22 was inadvertently listed as 0.689 in the original RAI response. This was the result of an error identified in the old calculations that has been subsequently corrected and factored into the latest analysis.**

Conclusion:

Summary of Corrosion Rates of UT measurements taken through year **2006**

- There is no **observable** ongoing corrosion at **three** elevations (51' 10", 60' 10", **and 87'5"**)
- Based on statistical analysis, one location at elevation 50' 2" is undergoing a minor corrosion rate of **0.66 mils** per year.

Table –2 UT Thickness measurements for the Sand Bed Region of the Drywell Shell

Location Bay	Sub Location	Dec 1986	Feb 1987	Apr 1987	May 1987	Aug 1987	Sep 1987	Jul 1988	Oct 1988	Jun 1989	Sep 1989	Feb 1990	Apr 1990	Mar 1991	May 1991	Nov 1991	May 1992	Sep 1992	Sep 1994	Sep 1996	Oct 2006
1D									1.115										1.101	1.151	**1.122**
3D									1.178										1.184	**1.175 (4)**	**1.180**
5D									1.174										1.168	1.173	**1.185**
7D									1.135										1.136	1.138	**1.133**
9A									1.155										1.157	1.155	**1.154**
9D		1.072							1.021	1.054	1.020	1.026	1.022	0.993	1.008	0.992	1.000	1.004	0.992	1.008	**0.993**
11A				0.919	0.905	0.922	0.905	0.913	0.888	0.881	0.892	0.881	0.870	0.845	0.844	0.833	0.842	0.825	0.820	0.830	**0.822**
11C	Bottom				0.917	0.954	0.916	0.906	0.891	0.877	0.891	0.870	0.865	0.858	0.863	0.856	0.882	0.859	0.850	0.883	**0.855**
	Top				1.046	1.109	1.079	1.045	1.009	1.016	1.005	0.952	0.977	0.982	**1.002 (3)**	0.964	1.010	0.970	**0.982 (4)**	1.042	**0.958**
13A		0.919							0.905	0.883	0.883	0.862	0.853	0.855	0.853	0.849	0.865	0.858	**0.837 (4)**	**0.853 (4)**	**0.846**
13D (1)	Bottom								**0.962 (1)**				**0.932 (1)**	0.909	0.901	0.900	0.931	0.906	0.895	0.933	**0.904**
	Top													1.072	1.049	1.048	1.088	1.055	1.037	1.059	**1.047**
13C (1)																		**1.149 (1)**	**1.140 (1)**	**1.154 (1)**	**1.142**
15A									1.120										1.114	1.127	**1.121**
15D		1.089							1.056	1.060	1.061	1.059	1.057	1.060	1.050	1.042	1.065	1.058	1.053	1.066	**1.053**
17A	Bottom	0.999							0.957	0.965	0.955	0.954	0.951	0.935	0.942	0.933	0.948	0.941	0.934	0.997	**0.935**
	Top	0.999							1.133	1.130	1.131	1.128	1.128	1.131	1.129	1.123	1.125	1.125	1.129	1.144	**1.122**
17D			0.922		0.895	0.891	0.895	0.878	0.862	0.857	0.847	0.836	0.829	0.825	0.829	0.822	0.823	0.817	0.810	**0.848 (4)**	**0.818**
17/19	Top								0.982	1.019	1.131	0.990	0.986	0.975	0.969	0.954	0.972	0.976	0.963	0.967	**0.964**
	Bottom								1.004	0.999	0.955	1.010	1.006	0.987	0.982	0.971	0.990	0.989	0.975	0.991	**0.972**
19A			0.884		0.873	0.859	0.858	0.849	0.837	0.829	0.825	**0.812 (2)**	0.808	0.817	0.803	0.803	0.809	0.800	0.806	0.815	**0.807**
19B					0.898	0.892	0.888	0.864	0.857	0.826	0.845	**0.840 (2)**	0.837	0.853	0.844	0.846	0.847	0.840	0.824	0.837	**0.848**
19C					0.901	0.888	0.888	0.873	0.856	0.845	0.845	0.831	0.825	0.843	0.823	0.822	0.832	0.819	0.820	**0.854 (4)**	**0.824**

Table –2 UT Thickness measurements for the Sand Bed Region of the Drywell Shell

Table 2 Notes:

1. **The Location Bay identifications for 13C and 13D were inadvertently reversed in the original RAI response, and erroneous low values were entered for Location Bay 13C. There is no impact on the analysis, as this was a transcription error between the calculation and Table 2.**

2. **The February 1990 values for Location Bays 19A and 19B were inadvertently reversed in the original RAI response. There is no impact on the analysis, as this was a transcription error between the calculation and Table 2.**

3. **The May 1991 value for Location Bay 11C Top was inadvertently reported as 1.018" (versus 1.0018" which rounds to 1.002") in the original RAI response. There is no impact on the analysis, as this was a transcription error between the calculation and Table 2.**

4. **The remaining changes are minor errors identified in the old calculations that have been subsequently corrected and factored into the latest analysis.**

IWE Program Inspections/Actions Performed During 2006 Refueling Outage

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.	1. Ultrasonic inspections of the drywell shell at locations previously measured, as outlined in the previous column, were performed. Review of the 1992, 1994, 1996 and 2006 data for all grids show that these monitored locations have not experienced any observable corrosion. This conclusion is based on a statistical comparison with the mean thicknesses measured in 1992, 1994, 1996 and 2006 at each location.

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded. 3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage. • The sand bed region drains will be monitored daily during refueling outages. If leakage is detected, procedures will be in place to determine the source of leakage and investigate and address the impact of leakage on the drywell shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage. Any degraded coating or moisture barrier will be repaired.	2. Strippable coating was applied to the reactor cavity liner prior to flooding the cavity with water for refueling activities. 3. The reactor cavity seal leakage trough drain was monitored for leakage daily after the reactor cavity was flooded up for refueling. There was a small stream of water (approximately one gallon per minute) observed to be coming from the reactor trough drain line. This rate was observed to be consistent throughout the period that the cavity was filled with water. Also, the sandbed region drain lines were monitored daily during the outage, after the cavity was flooded. No leakage was observed from any of the drain lines, in the sand bed area itself, nor was any collected in the associated poly collection bottles. Note that the sand bed drains were checked to ensure that they were clear. Some debris was found and cleared from two of the five drain lines.

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.	4. 100% of the epoxy coating applied to the external surface of the drywell shell in the sandbed region in 1992 was inspected in accordance with the inspection specification and the condition of the coating was determined to be satisfactory (i.e., no evidence of flaking, blistering, peeling, discoloration or other signs of coating distress).
5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.	5. Visual and ultrasonic examinations of the drywell shell were performed from the inspection access trenches. Visual inspection of the trenches identified approximately 5" of standing water in the trench in Bay 5, and moisture in the trench in Bay 17, and minor surface oxidation on the exposed shell areas. The ultrasonic test measurements determined that the drywell shell retains significant thickness margin in these areas. Also, additional concrete was excavated during 1R21 to expose approximately six more inches of previously embedded drywell shell surface at the bottom of the trench in bay 5 for inspection. UT results indicate that the average thickness in this area of the shell is approximately 0.041 inches (41 mils) below the nominal thickness of 1.154 inches, signifying that

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
	substantial margin exists in this previously embedded plate material.
7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.	7. UT thickness measurements in the upper drywell were taken. Statistical evaluation of the mean data indicates that the upper drywell shell is not undergoing observable corrosion, with the exception of one grid location. Analysis of the data at that grid location indicates a corrosion rate of 0.66 mils per year.
9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).	9. 106 areas that had been identified in 1992 as locally thinned were ultrasonically examined. These areas are geometrically distributed throughout the periphery of the drywell shell, at various elevations within the sand bed region. The results indicate that all the measured local thicknesses meet the established design basis criteria.
10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at four locations using the 6"x6" grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial	10. Two sets of UT thickness measurements were taken at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell, using a 6"x6" grid. Evaluation of these first-time readings shows that the mean and individual thicknesses currently meet acceptance criteria, with adequate margin. Note that, per the commitment, an additional two sets of measurements will be taken at different azimuths at

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).	this elevation prior to the period of extended operation.
11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at four locations using the 6"x6" grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).	11. Two sets of UT thickness measurements were taken in the drywell shell knuckle area at the junction between the 0.640 inch thick and 2.625 inch thick plates, using a 6"x6" grid. Evaluation of these first-time readings shows that the mean and individual thicknesses currently meet acceptance criteria, with adequate margin. Note that, per the commitment, an additional two sets of measurements will be taken at different azimuths at this elevation prior to the period of extended operation.
12. When the sand bed region drywell shell coating inspection is performed (commitment 27, item 4), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.	12. A visual inspection of the seal at the junction between the sand bed region concrete and drywell shell was performed in all 10 bays. The inspection revealed the seal at this junction to be in acceptable condition with no repairs required.
13. The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.	13. The reactor cavity trough drain was inspected with a boroscope and verified to be clear.

Oyster Creek Document Distribution Sheet

TITLE/SUBJECT: Information from October 2006 Refueling Outage Supplementing AmerGen Energy Company, LLC (AmerGen) Application for a Renewed Operating License for Oyster Creek Generating Station (TAC No. MC7624)

COGNIZANT INDIVIDUAL: **Fred Polaski**

SPECIAL HANDLING INSTRUCTIONS:
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Maintenance: J. Magee	NMB	E
Training: J. Vaccaro	Bldg 12	E
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Outage: S. Berg	OCAB-2	
Rad Pro/Chem: J. Renda	AOB	
Work Management: M. Button	OCAB-2	E

AmerGen/Exelon

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Plant Systems Engineering: S. Hutchins	OC	E
Lic. Renewal: T. E. Quintenz	OC	E
Chem/Env Dept Files	AOB	
Reg Assurance Dept Files	**05040**	E

Other

K. Barnes	OCAB-2	E
C. Duffy	OCAB-2	E

STANDARD RECORDS RETENTION SCHEDULE #	FILE CODE / (REFERENCE #)	RECORD NUMBER	RECORD NAME	RECORD DATE
	05040	2130-06-20426	Information from October 2006 Refueling Outage	12/3/06

GPU Nuclear
OCC FILE COPY
OYSTER CREEK

Material Nonconformance Report

"ORIGINAL-IN-RED"

Unit: ☐ TMI-1 ☐ TMI-2 ☒ Oyster Creek

20.02.03.13
93-036-0530

Page 1 of

RELEASE

MNCR Number	92018
REC NO	
REV	
DATE	
RECTYPE	002-01
LOCATION	
FORMNO	N1975
RETENTION	PERM

1. Identification

EXPEDITE

Originator: ABDUL R. BAIG Dept/Date/Time: TF/12-26-92/4:10 PM

Material, Part, Component, etc.: CONCRETE FLOOR

Location: REACTOR BUILDING TORUS ROOM - DRYWELL SHIELD WALL SAND BED

Manufacturer (name): NA Vendor # NA

P.O.# NA P.O. Item NA Spec #

B.A. # 402950 WA/JO 038968 / 036630

System: REACTOR BUILDING / ~~PM CONT~~ System No. 153 ~~[illegible]~~

Dwg. No. BR 4058-2 PIR/RIR # Other

Nonconforming to (requirements):

DESIGN CONFIGURATION PER BR 4058-2

Description of Nonconformance: DRAWING BR 4058-2 SHOWS A DRAINAGE CHANNEL IN THE SAND BED CONCRETE FLOOR AT ELEV. 8'-11 1/4". HOWEVER DURING OUR INSPECTIONS DURING THE SAND REMOVAL TASK IT HAS BEEN FOUND THAT THE DRAINAGE CHANNEL IS NON EXISTENT. IT APPEARS THAT DURING THE PLANT CONSTRUCTION PHASE ~~AFTER THE [illegible]~~ SAND BED AREA AND WAS NOT FINISHED OFF AFTER CONCRETE POUR IN ACCORDANCE WITH THE DESIGN SHOWN ON THE ABOVE DRAWING. THE FLOOR APPEARS VERY UNEVEN AND THERE ARE SOME VOIDS IN THE CONCRETE CLOSE TO THE DRYWELL WALL. 12/28/92

*ASSUMES NOT INSTALLED IN ANY BAYS BASED STANDARD CONDITIONS NOTED IN 6 BAYS DURING SAND REMOVAL

Hand carry to Quality Control Manager (normal working hours) or Unit/Group Shift Supervisor (backshift/weekend).

2. Evaluation & Validation

POTENTIALLY REPORTABLE:

	QA PLAN SCOPE	10CFR50	10CFR21	10CFR71	10CFR73.71	L.E.R.
Yes:	■	☐	☐	☐	☐	☐
No:	☐	■	■	■	■	■

Evaluated By (name): [signature] Date/Time: 12/28/92 @ 0750 HRS

QC Mgr. Validation: Rodney [signature] Date/Time: 12/28/92 @ 0810 HRS

If evaluated to be potentiall reportable, notify U/GSS and send copy of MNCR to Licensing.

U/GSS Notified: ☐ Yes ■ No Date/Time:

Hold Tags Issued: ☐ Yes ■ No No. of Tags:

Tags Installed By (name): Date/Time:

Material Segregation Required: ☐ Yes ■ No

Segregation Verified By (name): Date/Time:

DEVIATION REPORT ☐ YES ■ NO ☐ N/A

ACTION PARTY (name): LEFLER Dept: TF

1000-ADM-7215.01-1 (09-90) **Forward to Responsible Individual/Department (Action Party)** N1975 (09-90)

OCC FILE COPY
OYSTER CREEK

Material Nonconformance Report

"ORIGINAL-IN-FILE"

Unit: ☐ TMI-1 ☐ TMI-2 ☒ Oyster Creek

20.02.03.13
93-036-0530

Outage

Page 1 of

PLEASE

MNCR Number 912018
REC NO
REV
DATE
RECTYPE 002-01
LOCATION
FORMNO N1975
RETENTION PERM

1. Identification

EXPEDITE

Originator: ABDUL R. BAIG Dept/Date/Time: TF/12.26.92/4:10 PM
Material, Part, Component, etc.: CONCRETE FLOOR

Location: REACTOR BUILDING TORUS ROOM - DRYWELL SHIELD WALL SAND BED
Manufacturer (name): NA Vendor # NA
P.O.# NA P.O. Item NA Spec #
B.A. # 402950 WA/JO 038968 / 036630
System: REACTOR BUILDING / ~~PRI CONT~~ System No. 153 / ~~235~~
Dwg. No. BR 4058.2 PIR/RIR # Other
Nonconforming to (requirements):
DESIGN CONFIGURATION PER BR 4058.2

Description of Nonconformance: DRAWING BR 4058.2 SHOWS A DRAINAGE CHANNEL IN THE SAND BED CONCRETE FLOOR AT ELEV. 8'-11 1/4". HOWEVER, DURING OUR INSPECTIONS DURING THE SAND REMOVAL TASK IT HAS BEEN FOUND THAT THE DRAINAGE CHANNEL IS NON EXISTENT. IT APPEARS THAT DURING THE PLANT CONSTRUCTION PHASE ~~AFTER THE BOTTOM INSTALL~~ SAND BED AREA WAS NOT FINISHED OFF AFTER CONCRETE POUR IN ACCORDANCE WITH THE DESIGN SHOWN ON THE ABOVE DRAWING. THE FLOOR APPEARS VERY UNEVEN AND THERE ARE SOME VOIDS IN THE CONCRETE CLOSE TO THE DRYWELL WALL. AKB 12/28/92

*ASSUMES NOT INSTALLED IN ANY BAYS BASED STANDARD CONDITIONS NOTED IN 6 BAYS DURING SAND REMOVAL

Hand carry to Quality Control Manager (normal working hours) or Unit/Group Shift Supervisor (backshift/weekend).

2. Evaluation & Validation

POTENTIALLY REPORTABLE:

	QA PLAN SCOPE	10CFR50	10CFR21	10CFR71	10CFR73.71	L.E.R.
Yes:	■	☐	☐	☐	☐	☐
No:	☐	■	■	■	■	■

Evaluated By (name): [signature] Date/Time: 12/28/92 @ 0750 HRS
QC Mgr. Validation: [signature] Date/Time: 12/28/92 @ 0810 HRS

If evaluated to be potentiall reportable, notify U/GSS and send copy of MNCR to Licensing.

U/GSS Notified: ☐ Yes ■ No Date/Time:
Hold Tags Issued: ☐ Yes ■ No No. of Tags:
Tags Installed By (name): Date/Time:
Material Segregation Required: ☐ Yes ■ No
Segregation Verified By (name): Date/Time:

DEVIATION REPORT
☐ YES ■ NO ☐ N/A

ACTION PARTY (name): LEFLER Dept: T.F.

10CFR-ADM-7215.01-1 (09-90) **Forward to Responsible Individual/Department (Action Party)** N1975 (09-90)

GPU Nuclear

Material Nonconformance Report

MNCR Number 912911 09

Page 2 of ____

3. Action Party Evaluation and Disposition By (name) ABDUL R. BUG Dept TT Date 12 Nov

Evaluation of Cause: ☐ Human Factors ☐ Procedure Related ☐ Material Related ☐ Program Related
☒ Other ORIGINAL PLANT CONSTRUCTION DEFECT

Proposed Disposition: ☒ *Repair ☐ *Use-as-is ☐ Rework ☐ Scrap
☐ Other (describe as necessary) ____

***Requires Engineering Evaluation and Approval**

4. Engineering Evaluation & Disposition By (name) ____ Dept ____ Date ____

Disposition Concurrence ☐ Yes ☐ No If NO, recommendation is:
☐ *Repair ☐ *Use-as-is ☐ Rework ☐ Scrap ☐ Other ____

***Requires Technical Justification**

Justification: (include applicable work documents, limitations, etc.) ____

Reinspection/Retest Requirements (as applicable) ☐ N/A ____

Technical Corrective Action (as applicable). Check, as appropriate, of corrective action requires change to:
☐ Design ☐ Procedure ☐ Specification ☐ Drawing ☐ FSAR ☐ N/A
☐ Manual ☐ Tech. Spec. Document No. ____

Safety Requirements:
Safety Evaluation? ☐ Yes ☐ No SE# ____ Rev. ____
Safety Verification? ☐ Yes ☐ No DV# ____ Rev. ____
Fire Hazards Analysis? ☐ Yes ☐ No FHA# ____ Rev. ____
Prepared By (name) ____ Dept ____

5. Engineering Concurrence ☐ Yes ☐ No If NO, provide reasons: ____

NDE/ISI ____ Date ____ ☐ N/A
ANI/ANII ____ Date ____ ☐ N/A
C... ____ Date ____ ☐ N/A
QC Manager/Designee ____ Date: ____

6. Quality Control Verification & Closeout

Verification of satisfactory completion of material disposition and initiation of technical corrective action.

Verification Method: ____

Complete following as appropriate:
Inspection Report No. ____ Other ____
Verified By (name/date) ____
Tags/Segregation Removed By (name/date) ____

7. Final Package Review

Quality Control Manager ____ Date ____

GPU Nuclear

Material Nonconformance Report

MNCR Number 192191189

Page 2 of 4

3. Action Party & Situation and Disposition By (name) ABDUL R. BAIG Dept TT Date 12/30/92

Evaluation of Cause: ☐ Human Factors ☐ Procedure Related ☐ Material Related ☐ Program Related ☒ Other ORIGINAL PLANT CONSTRUCTION DEFECT

Proposed Disposition: ☒ *Repair ☐ *Use-as-is ☐ Rework ☐ Scrap ☐ Other (describe as necessary)

*Requires Engineering Evaluation and Approval

4. Engineering Evaluation & Disposition By (name) KENNETH L. WHITMAN Dept E&D Date 12/30/92

Disposition Concurrence ☒ Yes ☐ No If NO, recommendation is: ☒ *Repair ☐ *Use-as-is ☐ Rework ☐ Scrap ☐ Other

*Requires Technical Justification

Justification: (include applicable work documents, limitations, etc.) REPAIR FLOOR W/ DEVOE-DEVRAN 184 EPOXY. PROVIDE SMOOTH SURFACE OVER INTERNAL FLOOR AREA FROM W/TOP OF DAMS. SLOPE ADJACENT TO DAMS SUFFICIENTLY (CONT. ON PAGE 4)

Reinspection/Retest Requirements (as applicable) ☐ N/A PER OC MM 402950-010 INSPECT FLOOR AREA AFTER EACH COATING TO REPAIR EPOXY IF STILL FAILS, THE CENTER IS ACCEPTED AFTER FIRST REPAIR. } AB 12/31/92

Technical Corrective Action (as applicable). Check, as appropriate, if corrective action requires change to: ☐ Design ☐ Procedure ☐ Specification ☒ Drawing ☐ PM/R ☐ N/A ☐ Manual ☐ Tech. Spec. Document No. BR 4058-2

Review Requirements:

Safety Evaluation? ☒ Yes ☒ No SE# 402950-011 Rev. 1

Design Verification? ☐ Yes ☒ No DV# Rev.

Fire Hazards Analysis? ☒ Yes ☒ No FHA# 402950-010 Rev. 2

Concurred By (name) Kenneth L. Whitman / Abdul R. Baig 12/31/92 Dept E&D / EP

5. Disposition Concurrence ☒ Yes ☐ No If NO, provide reasons:

NDE/ISI Date ☒ N/A

AI/ANI/ANI Date ☒ N/A

Other Date ☒ N/A

QC Manager/Designee Rodney L. Timm Date: 12/31/92

6. Quality Control Verification & Closeout

Verification of satisfactory completion of material disposition and initiation of technical corrective action.

Verification Method: INSPECTED THE REPAIRED SAND BED FLOOR IN ALL TEN BAYS IN ACCORDANCE WITH THE REQUIREMENTS OF OC MM 402950-010. THE REPAIRS HAVE BEEN DONE SATISFACTORILY AND ARE ACCEPTABLE.

Complete following as appropriate:

Inspection Report No. J.O. # 36630 Other

Verified By (name/date) ABDUL R. BAIG Abdul R. Baig 1/25/93

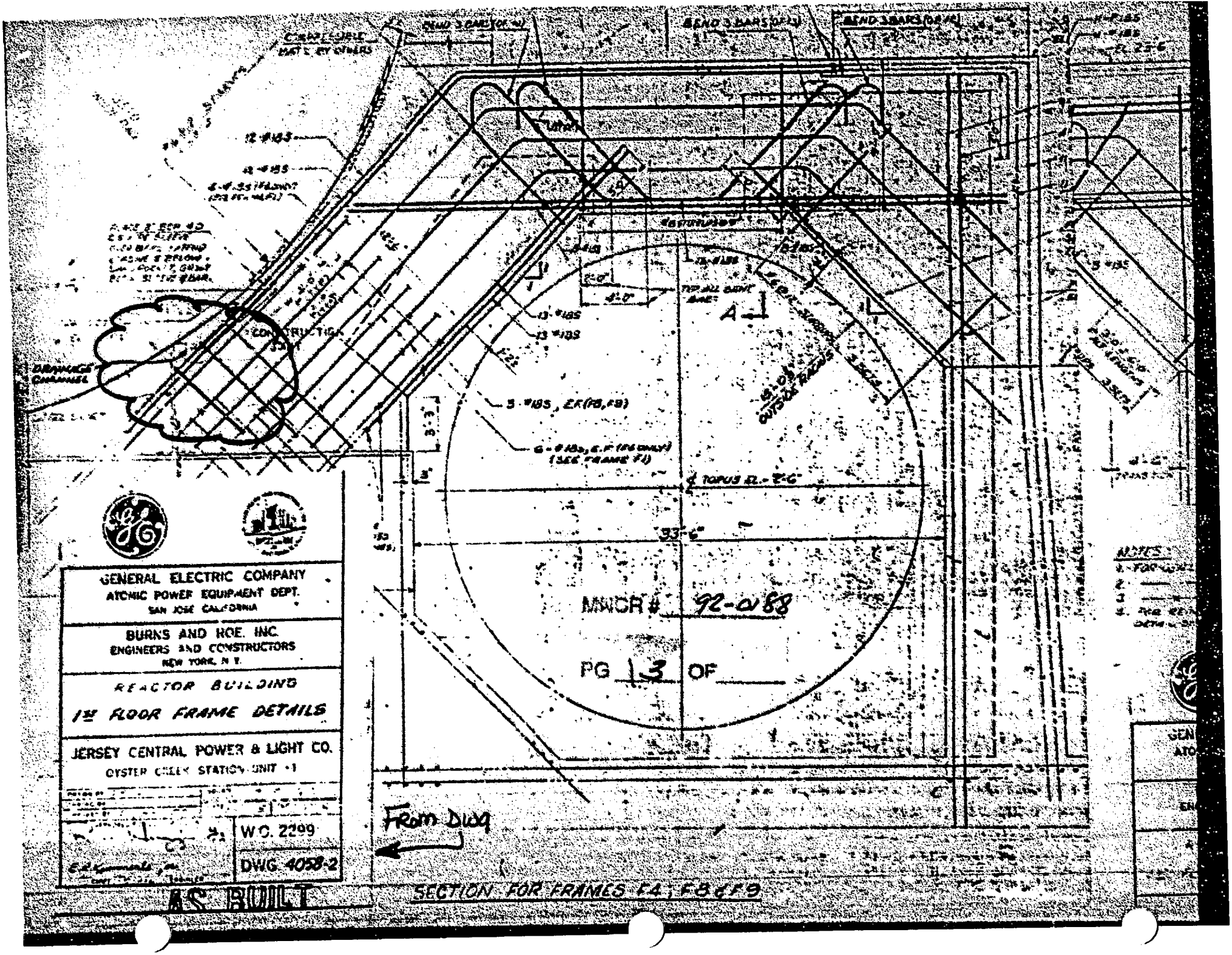
Tags/Segregation Removed By (name/date) N/A

7. Final Package Review

Quality Control Manager Rodney L. Timm Date 1/25/93

N192B 100-00A

TOTAL P.04


GENERAL ELECTRIC COMPANY
ATOMIC POWER EQUIPMENT DEPT.
SAN JOSE CALIFORNIA
BURNS AND ROE, INC.
ENGINEERS AND CONSTRUCTORS
NEW YORK, N.Y.
REACTOR BUILDING
1st FLOOR FRAME DETAILS
JERSEY CENTRAL POWER & LIGHT CO.
OYSTER CREEK STATION UNIT #1
W.O. 2299
DWG 4058-2
MWCR # 92-0188
PG 13 OF
From Dwg
AS BUILT
SECTION FOR FRAMES F4, F8 & F9
33'-6"
DRAINAGE CHANNEL

REPAIR REQUIREMENTS (CONT FROM SHEET 2)

TO ENSURE ALL WATER DRAINS AWAY FROM THE DRYWELL. THE TROUGH (DRAINAGE CHANNEL) SHOWN ON DRAWING 4058-2 IS NOT NEEDED AND SHOULD NOT BE FORMED INTO THE EPOXY. ENSURE THAT EPOXY IS APPROXIMATELY LEVEL WITH THE TOP OF THE DRAINS AND THAT THE DRAINS ARE NOT PLUGGED OR FILLED WITH EPOXY. IF THE EPOXY IS PLACED WITH THE REACTOR CAVITY FLOODED, INSPECT THE FLOOR AFTER THE WATER IS REMOVED. SEAL ANY CRACKS BETWEEN THE EPOXY AND THE DRYWELL WITH DEVOE - PREPRIME 167 SEALER OR WITH ADDITIONAL DEVOE - DEVRAN 184.

DEVOE - DEVRAN 184 SHALL BE APPLIED IN ACCORDANCE WITH MANUFACTURER'S RECOMMENDATIONS INCLUDING THE APPLICATION OF A PRIMER COAT OF DEVOE - PREPRIME 167 PRIOR TO APPLICATION OF DEVRAN.

10/10/06 20:48:51
ORIGINAL red

GPU Nuclear — Material Nonconformance Report

MNCR Number 87-240

RECNO
REV
DATE
RECTYPE 002-01
LOCATION
FORMNO A 0001975
RETENTION PERM

Unit: ☐TMI-1 ☐TMI-2 ☒Oyster Creek
☐AABO ☒HO2O ☐BABO ☐AI00 ☐HO3O
CARIBS 11-28-88

Page 1 of 2

1. Identification

Originator: ROD TURNER Dept/Date/Time: QC9881/11/2/87/1303
Material, Part, Component, etc.: RX CAVITY LINER
Location: EL 119 OF RX BLDG
Manufacturer (Name): N/A Code: ASME SECTION VIII
P.R.# N/A Line # N/A Spec # N/A
BA # 323435 Work Authorization #
System: CONTAINMENT #240 System Tag No. N/A
Dwg. No. N/A Heat Code No. N/A Other N/A
Nonconforming to (requirements): 6130-QAP-7209.27 R-0 VISUAL INSPECTION OF COMPONENTS & ASME SECTION VIII

Description of Nonconformance: THRU WALL TYPE INDICATION/DEFECT WAS DETECTED ON ONE SPOT WELD ON EAST WALL APPROX. 5' UP FROM TOP TREAD ABOUT 4' TO LEFT OF UP/DOWN LADDER. FURTHER INSPECTION OF THIS INDICATION & OTHER AREAS OF LINER ARE CONTINUING; DEFECTS WILL BE DOCUMENTED ON NDE DATA SHEETS.

DEFECT APPEARS TO BE THE RESULT OF BASE MATERIAL (LINER) PULLING AWAY FROM EDGES OF SPOT WELD ON THREE SIDES APPROX SIZE: 3/4" ON 2 SIDES AND 1/8" ON ONE END PSD 11-2-87

Hand carry to Quality Control Manager (normal working hours) or Unit/Group Shift Supervisor (backshift/weekend).

2. Evaluation & Validation

DEVIATION REPORT SUBMITTED PSD 11-2-87

POTENTIALLY REPORTABLE:

	Important To Safety	10CFR50	10CFR21	10CFR71	10CFR73.71	L.E.R.
YES:	☑	☐	☐	☐	☐	☑
NO:	☐	☑	☑	☑	☑	☐

Evaluated By (Name): Paul S Dawson Date/Time: 11-2-87 1435
QC Mgr. Validation: Paul S Dawson Date/Time: 11-2-87 1435

If evaluated to be potentially reportable, notify U/GSS and send copy of MCNR to licensing.

U/GSS Notified: ☑YES ☐NO Date/Time: RBrown 11-2-87 1435
Hold Tags Issued: ☐YES ☑NO No. of Tags: N/A
Tags Installed By (Name): N/A Date/Time: N/A
Material Segregation Required: ☐YES ☑NO
Segregation Verified By (Name): N/A Date/Time: N/A
ACTION PARTY (Name): L. LAMMERS Dept: P MATERIEL

Forward to responsible individual/department (Action Party).

FORM 1000-ADM-7215.01-1 (9/85)

A0001975A 9-85

GPU Nuclear MATERIAL NONCONFORMANCE REPORT

MNCR Number 87-240
Page 2 of 2
REV 1

3. Action Party Evaluation and Disposition By (Name) _____ Dept _____ Date _____

Evaluation of Cause: [ ] Human Factors [ ] Procedure Related [ ] Material Related [ ] Program Related
[ ] Other _____

Proposed Disposition: [ ] *Repair [ ] Use-as-is* [ ] Rework [ ] Scrap
[ ] Other (Describe as necessary) _____

*Requires Engineering Evaluation and Approval

4. Engineering Evaluation and Disposition By (Name) JOHN A. MARTIN Dept TECH. FUNCTIONS Date 10/10/88

Disposition Concurrence: [ ] YES [ ] NO If NO, recommendation is:
[ ] *Repair [X] *Use-as-is [ ] Rework [ ] Scrap [ ] Other _____
*Requires Technical Justification

Justification: (Include applicable work documents, limitations, etc.) PERMANENT REPAIR OR INSPECTIONS NOT NECESSARY. INDICATIONS WILL BE COATED PRIOR TO FLOOD UP AND COATING REMOVED AT END OF OUTAGE. THIS MATERIAL WILL ALSO BE REMOVED DURING OUTAGE UNTIL PERMANENT REPAIR IS ENGINEERED FOR ENTIRE CONTAINMENT

Re-inspection/Retest Requirements (As Applicable) [ ] N/A
NONE REQUIRED WORK COVERED UNDER JOB ORDER 9971 AND SP-1302-22-02 AND SP 1302-48-002

Technical Corrective Action(As Applicable). Check, as appropriate, if corrective action requires change to:
[ ] Design [ ] Procedure [ ] Specification [X] Drawing [ ] FSAR [X] NTR PSD 10-14-88
[ ] Manual [ ] Tech Spec Document No. GPUN-A 0137 GU

Review Requirements:

Safety Evaluation?	[ ] Yes	[X] No	SE# 328257-002	Rev.	1
Design Verification?	[ ] Yes	[X] No	DV#	Rev.	
Fire Hazards Analysis?	[ ] Yes	[X] No	FHA#	Rev.	

Concurred By (Name): Christopher Patterson 10/10/88 Dept.: TECH FUNCTIONS
Plnt Engr Mgr/Tech Func Site Supv/Desg Date: 10/10/87
Forward to Quality Control

5. Disposition Concurrence [X] Yes [ ] No If no, provide reason:

QA Engineering	Date	N/A [ ]	
SPP/SME/ISI	Date	[ ]	
AI/ANI/AMII	Date	[ ]	QC Manager/Designee — Date 10/10/88

6. Quality Control Verification and Closeout

Verification of satisfactory completion of material disposition and initiation of technical corrective action.
Verification Method: N/A

Complete following as appropriate:
Inspection Report No.: _____ Test Report No.: _____
Work/Shipping Order No.: _____ Other: _____
Verified By (Name/Date): _____
Tags/Segregation Removed By (Name/Date): _____

7. Final Package Review

Quality Control Manager _____ Date 10/10/88

GPU Nuclear **Technical Functions**

Safety/Environmental Determination and 50.59 Review

UNIT OC/NGS PAGE 1 OF 2

ACTIVITY REPAIR OF REACTOR CAVITY AND STORAGE POOL LINING SE No. 32[illegible]

DOCUMENT NO. SE-1302.22-006 DOC REV. NO. 3 SE Rev. No. Ø

DOCUMENT TITLE (Of Modification) Repair of Reactor Cavity and Storage Pool Lining

Type of Activity Repair
(Modification, procedure, test, experiment, or document)

1. Is this activity/document listed in Section I or II of the matrices in Corporate Procedure 1000-ADM-1291.01? ☒ Yes ☐ No

   If the answer to question 1 is "no" stop here. (Section IV activities/documents should be reviewed on a case-by-case basis to determine if this procedure is applicable.) This procedure is not applicable and no documentation is required. If the answer is "yes" proceed to question 2.

2. Is this a new activity/document or a substantive revision to an activity/document? (See Exhibit 3, paragraph 3, this procedure for examples of non-substantive changes) ☒ Yes ☐ No

   If the answer to question 2 is "no" stop here. This procedure is not applicable and no documentation is required. If the answer is "yes" proceed to answer all remaining questions. These answers become the Safety/Environmental Determination and 50.59 Review.

3. Does this activity/document have the potential to adversely affect nuclear safety or safe plant operations? ☐ Yes ☒ No

4. Does the activity/document require revision of the system/component description in the FSAR or otherwise require revision of the Technical Specifications or any other Licensing Basis Document? ☐ Yes ☒ No

5. Does the activity/document require revision of any procedural or operating description in the FSAR or otherwise require revision of the Technical Specifications or any other Licensing Basis Document? ☐ Yes ☒ No

6. Are tests or experiments conducted which are not described in the FSAR, the Technical Specifications or any other Licensing Basis Document? ☐ Yes ☒ No

7. Does this document involve any potential Non-Nuclear environmental impact? ☐ Yes ☒ No

8. Are the design criteria as outlined in TMI-1 SDD-T1-000 Div. I or OC-SDD-000 Div. I Plant Level Criteria affected by the activity/document? ☐ Yes ☒ No

   If yes, indicate how resolved _____

If any of the answers to questions 3, 4, 5, or 6 are yes, proceed to EXHIBIT 6 and prepare a written safety evaluation. If the answers to 3, 4, 5, or 6 are no, this precludes the occurrence of an Unreviewed Safety Question or Technical Specifications change. If the answer to question 7 is yes, either redesign or provide supporting documentation which will permit Environmental Licensing to determine if an adverse environmental impact exists and if regulatory approval is required (Ref. LP-010). If in doubt, consult the Radiological and Environmental Controls Division or Environmental Licensing for assistance in completing the evaluation.

Signatures		Date
Engineer/Originator	[illegible]	11-5-87
Section Manager	[illegible]	11-5-87
Responsible Technical Reviewer	J. H. Corner	11/5/87
Other Reviewer(s)		

N 5047 (07-87)

This activity identifies, removes and repairs defects in the equipment storage pool and reactor cavity. The repair activity restores the structural integrity equivalent to or better than the original design and minimize if not eliminate the potential for leakage from the pool and/or cavity. This, in turn, will reduce or eliminate the potential for drywall liner corrosion.

All work will be performed to specifications equal to or better than original construction, and the repair method adequacy will be verified using appropriate NDE techniques (visual and dye penetrant). Therefore, the activity performed by SP-1302-22-006 does not have any adverse effects on plant safety but in effect will enhance it.

GPU Nuclear

Release No. 056761

Document Release Form

Date 11-5-87
Page 1 of 1

Release Action

To: E D&CC

- ☐ As-Builts
- ☒ Record
- ☐ Operations/Maintenance/Test
- ☐ Construction
- ☐ Procurement
- ☐ Hold Construction
- ☐ Void

Originator J. ADAMOVICH Dept./Orgr. MC/TF Tel 7038 Unit OCNGS

BA# 323435 System# 181 WO/SO 8150 57032 IS

List of Released Items

Company	Document No.	Sheet	Rev.	Title
GPUN	SE 323435-009 006	2	0	Repair of Reactor Cavity and Storage Pool Liner

Special Instructions

References/Attachments

Approved: [signature] Date 11/4/87

cc B DELANY / J DeBLASIO / J HAMILTON / M RADKOWSKY

Original (yellow) to ED & CC

FORM 5000-ADM-1251.02-1

A0001080A 1-86

10/10/06 20:48:51

Burton 11.2.87

11M APPROVED

MILESTONE = N/A

DCC File No.

GPU Nuclear

Maintenance, Construction & Facilities Short Form

Oyster Creek Nuclear Generating Station-Unit 1

Priority: 30

Work Request No: 47955

Work Request (MP3)

Work Request Originator	Home Base	Date	Dept. Mgr./Supv.	Date	Component Ident MISC	System Code
T.E. FARMER	A120	11-1-87	[signature]	11/02/87	153 SYSTEM GEN. WORK - Rx BLDG	153

Bldg/Loc.: RX Elev.: 119

Description of Problem/Work Requested: ~~THIS COVERS THE REQUIREMENTS~~ ~~FOR THE REFUGUL~~ REPAIR OF DEFECTS IN THE STAINLESS STEEL LINING OF THE REACTOR CAVITY. THE DEFECTS CONSIST OF THRU-WALL AND SURFACE INDICATIONS DETECTED BY NDE INSPECTION OF WELD JOINTS.

Deficiency Tag Issued ☐ ✓

Technical Specification	Req'd Comp Date Time	CCL/CASL	Additional Requirements
YES ☒ NO ☐	N/A	YES ☒ NO ☐	☐EQ ☐ISI ☐IST ☒N/A

Comments

Plant Materiel Approval	Date	Responsible Organization	Principal Craft	MCF Approval	Date
[signature]	11/2/87	☒MCF ☐Plt. Mat'l.	☐Fac. ☐Elect. ☐I&C ☒Mech. ☐N/A		

Special ITS Reqm'ts

Special Safety and Work Condition Requirements - ITS

Approval | Date

Work Authorization

If YES, see applicable section or attachment	YES	NO	See Att. #
Is Job Important to Safety? (ITS)	X		
Is Fire Barrier Breached?			
Are welding documents required?	X		
Are grinding or burning permits required?	X		
Is R/NR stamp required?			
Is Radiological Engineering Review (RER) required?	X		87-058
Is a Radiation Work Permit (RWP) required?	X		
Is Post Maint./Installation Testing required?		X	
Is Switching, Tagging or Draining required?		X	
Is temporary variation required?		X	
Are QC Hold/Witness points required?			
Do Zone 1 or 2 requirements of Proc 119 apply?	X		
Is NRP required?			
Are security provisions altered or modified?		X	
Is 108.4-1 Form required?		X	
Is Security notification required?		X	
Is NML Inspection Program required?			
Hazardous waste tracking form required (RCRA)		X	

Procedure No.	Serial No
Attachments	
A	CURRENT TEST FOR WELDIN MACHINES
B	
C	
D	
E	
References	
A	
B	
C	
D	
E	
Budget Activity No.	323435
Work Order/Sub Order	AISD-51032
WICS Signature	
Cost Supv. Signature	
MCF Contracts	

Secondary Support Craft: ☐Mech. ☐Elect. ☐I&C ☐None Required

Job Planner	Date	Ext.	Grp. Maint./Ops Supv.	Area Supv.	Date	QC Notification	Date

Approval (GSS) to Start Work | Date | Remarks:

Copies: Original - Document Control Center; Yellow - MCF Technical Support; Pink - Quality Control; Goldenrod - Originator

NA1494 (0

DRF7567

GPU Nuclear

SPECIFICATION

SP-1302-22-006

IMPORTANT TO SAFETY

TECHNICAL SPECIFICATION FOR

OYSTER CREEK

NUCLEAR GENERATING STATION

REPAIR OF

REACTOR CAVITY AND STORAGE POOL LINING

PREPARATION A. COLLADO DATE 1/17/83

ENGINEERING APPROVAL DATE 1/17/83

QA CONCURRENCE DATE 1-17-83

REV 3

A0001081

GPU Nuclear

DOCUMENT NO. SP-1302-22-006

TITLE O.C.N.G.S. - REPAIR OF REACTOR CAVITY AND STORAGE POOL LINING

REV	SUMMARY OF CHANGE	APPROVAL	DATE
1	Revised paragraphs 2.3, 2.4, 3.1.2, 4.3, 4.4.1, 4.5.3, 4.5.5		1/21/83 1/26/83
2	Revised paragraphs 1.1, 1.2, 4.1, 4.2, 4.4.1 and 4.5.3 to include repairs to the reactor cavity lining.		6/15/83 6/9/83
3	Revised paragraphs 2.4, 2.6.2, 2.6.4, 4.4.2, 4.5.4, 2.6.3, 2.3		10/20/87 10/31/87

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1.0 SCOPE

1.1 This specification covers the requirements for the removal, repair and inspection of defects in the stainless steel lining of the storage pool and the reactor cavity at the Oyster Creek Nuclear Generating Station.

1.2 The defects consist of thru-wall and surface indications detected by the dye penetrant inspection of welded joints. Thru-wall indications have been verified by the Vacuum Box Test where appropriate.

2.0 REFERENCES

The following documents, or portions thereof as referenced in subsequent sections of this specification, form an integral part of this specification. For documents not specifically identified by date, the latest revision in effect in accordance with the date of this specification shall apply.

2.1 GPUN Operational Quality Assurance Plan for Oyster Creek

2.2 GPUN Welding Manual

2.3 GPUN Welding Standard 6150 Std. 7220.07

2.4 GPUN Welding Procedure Specification No. 811, 821, and 831

2.5 JCP&L Procedures

2.5.1 Procedure No. 119, Housekeeping

2.5.2 Procedure No. 107, Procedure Control

2.5.3 Procedure No. 120.1 Welding, Burning and Grinding Administrative procedure

2.5.4 Procedure No. 120, Fire Hazard

2.6 American Society of Mechanical Engineers (ASME), Boiler & Pressure Vessel Code

2.6.1 ASME Section IX, "Welding and Brazing Qualifications"

2.6.2 ASME Section VIII, "Pressure Vessel Code", Div. 1

2.6.3 ASME Section II, Part C, "Welding Rods, Electrodes and Filler Metals"

2.6.4 ASME Section V - Non-Destructive Examination

2.7 GPUN Vacuum Test Procedure No. MTNE-015

2.8 GPUN Liquid Penetrant Procedure No. MTIS-007

2.9 Burns & Roe Drawings and Specifications

2.9.1 Drawing No. 4056

2.9.2 Drawing No. 4057

2.9.3 Drawing No. 4068

2.9.4 Specification No. S-2299-45, Section 5C

2.10 General Electric Drawings

2.10.1 Drawing No. 237E516 Sh. 1

2.10.2 Drawing No. 237E547 Sh. 1 & 4

2.10.3 Drawing No. 237E975 Sh. 1 & 2

3.0 GENERAL REQUIREMENTS

3.1 Work to be provided and responsibilities.

3.1.1 The Oyster Creek Station Director shall be responsible for:

a. Implementing all operational prerequisites as required by this specification.

b. Supplying the necessary utility services.

c. Providing necessary security and health physics coverage during the repairs and inspection.

d. Providing technical and engineering support.

e. Determining repair areas

3.1.2 Oyster Creek Maintenance and Construction shall be responsible for:

a. Repair of the pool walls and floor, as required.

b. Equipment, welding materials, tools, labor and supervision necessary to conform to the requirements of this specification.

c. Repair procedure/work order required.

d. Welders and Weld Procedures Qualifications

3.1.3 Site Quality Assurance shall be responsible for:

a. Surveilling the inspection and repair work performed.

b. Compiling and maintaining documentation required by this specification.

c. NDE procedures, personnel and examinations.

3.2 Work by Others

No work will be provided by other than GPUN/JCP&L Organization under this specification.

4.0 DETAIL REQUIREMENTS

4.1 Description of Intended Use

Welding will be used for sealing all thru-wall and surface indication identified within the storage pool and the reactor cavity lining.

4.2 Environmental Conditions

The pool and cavity are located in the Reactor Building elev. 119'-3". Pool and cavity shall be cleaned and dried. Health Physics shall be contacted for the results of the most recent survey of the repair site for levels of radiation.

4.3 Prerequisites

The following conditions shall exist prior to performing work covered by this specification:

a. Repair procedures/work request written and approved.

b. Material and equipment available and released for use.

c. Plant job order initiated.

d. Quality Assurance Notified.

e. Group Shift Supervisor notified.

f. Radiation work permit obtained.

g. All defects are identified and weld MAPS available.

h. All ALARA requirements have been met.

4.4 Materials

4.4.1 The existing lining consists of ASTM-A240 Type 304L stainless steel of the following thickness:

a. Storage Pool

Walls: 1/8" thick sheets
Floor: 1/4" thick plates

b. Reactor Cavity

Shield plug steps: 1/2" thick plates, except base of lowest step is 1" thick plate

Cavity Wall: 1/4" thick plate.

4.4.2 The filler material to be used in the repair of defects shall be type ER 308L SFA-5.9 or E 308L-16 SFA5.4 conforming to ASME Section II, Part C.

4.5 Surface Preparation

4.5.1 Areas to be repaired shall be thoroughly cleaned and dried.

4.5.2 All defects shall be explored for depth by grinding, machining, brushing or filling to sound metal.

a. Machining and Grinding - use only silicon carbide or aluminum oxide grinding wheels not previously used on carbon steel or low alloy steel.

b. Brushing and Filing - use only stainless steel brushes not previously used on carbon steel or low alloy steel.

c. Carbon arc cutting is not permitted.

4.5.3 Thru-wall indications shall be removed for their entire length and depth maintaining a "V" shape groove configuration. For repair of welds without a metal backing member or welds with concrete backing, a 1/16" to 3/32" of material thickness shall remain at the root of the excavation.

4.5.4 Surface indications shall be removed by grinding, filing or machining. 10%

4.5.5 Removal of defects which are not thru-wall shall be verified by liquid penetrant examination with no indications greater than 1/16" (major dimension). Any indication greater than 1/16" shall be documented and dispositioned by the site Q.A/Q.C. and the Project Engineer.

4.5.6 Uncovered defects found during the excavation process of surface defects shall be reported to the Project Engineer for evaluation and corrective action using a Material Non-Conformance Report (MNCR).

4.6 Welding

4.6.1 Welding shall conform to the requirements of ASME Boiler and Pressure Vessel Code, Section VIII.

4.6.2 All welding and weld repair shall be performed in accordance with approved weld procedures and by welders qualified to the procedures in accordance with Reference 2.6.1.

4.6.3 Weld Rod shall conform to ASME Section II, Part C, SFA-5.9 or SFA 5.4 as applicable.

4.6.4 All welding shall be performed per reference 2.4.

4.6.5 In addition to the welding procedure, welding shall meet the requirements of NRC Req. Guide 1.44.

4.6.6 Heat Input shall be lower than 35000 joules per inch.

4.7 Surface Finish

4.7.1 All welds/repair welds shall be ground flush and smooth with liner plates (parent material). Ground surfaces shall be adequate for performing the required penetrant test.

4.8 Non-Destructive Examination

4.8.1 All weld repairs shall be visually and liquid penetrant (LP) examined in accordance with approved procedures and qualified personnel meeting the requirements of Ref. 2.6.4. Quality Assurance shall select the best suitable techniques for the given surface.

4.8.2 Acceptance criteria of weld repairs shall be no relevant indications (indications whose major dimensions are greater than 1/16 of an inch.)

The following relevant indications are unacceptable:

a. Any cracks or linear indications.

b. Rounded indications with dimensions greater than 3/16 inches.

c. Four or more rounded indications in a line separated by 1/16 inch or less edge to edge.

d. Ten or more rounded indications in any six square inches of surface with the major dimension of this area not to exceed six inches with the area taken in the most unfavorable location relative to the indications being evaluated.

4.9 Final Cleaning

4.9.1 Repaired surfaces shall be in the mechanically cleaned condition and free of scale and organic contaminants. Unused acetone, denatured alcohol or an approved PT Cleaner shall be used for solvent cleaning.

4.9.2 Cleaning agents shall contain less than 200 ppm sulphur or chlorides.

4.10 Safety Precautions

4.10.1 Working area shall be kept clean of flammable materials, especially when welding is being performed.

4.10.2 Fire extinguishers must be available whenever welding is being performed and a welding permit shall be obtained per the requirements of Plan Procedure 120.1.

4.11 Procedures

4.11.1 Procedures shall be used to control inspection, repair and welding in accordance with JCP&L Procedure No. 107.

5.0 QUALITY ASSURANCE

5.1 The repair of the storage pool lining is classified as Important to Safety.

5.2 All work and material covered by this specification are subject to inspection as per the GPUN Operational Quality Assurance Plan for Oyster Creek.

6.0 DOCUMENTATION

The following documentation shall be maintained as specified by GPUN Procedure EMP-017:

a. Results of NDE.

b. Welding Personnel Qualifications.

c. NDE procedures and personnel qualifications.

d. Welding procedures.

e. Weld MAPS identifying the repairs made.

f. Records of inspection revealing the defects to be repaired.