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**UNITED STATES OF AMERICA**
**NUCLEAR REGULATORY COMMISSION**

**ATOMIC SAFETY AND LICENSING BOARD**

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

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| In the Matter of: | ) | September 14, 2007 |
| | ) | |
| AmerGen Energy Company, LLC | ) | |
| | ) | Docket No. 50-219 |
| (License Renewal for Oyster Creek Nuclear Generating Station) | ) | |
| | ) | |

**AMERGEN ENERGY COMPANY, LLC**
**SURREBUTTAL STATEMENT OF POSITION**

## I. INTRODUCTION

In accordance with 10 C.F.R. § 2.1207(a)(1) and the Atomic Safety and Licensing Board's ("Board") April 17, 2007, and August 9, 2007 Memoranda and Orders,[1] AmerGen Energy Company, LLC ("AmerGen") hereby submits its SurRebuttal Statement of Position ("SurRebuttal") in response to Citizens' Rebuttal.[2] AmerGen's SurRebuttal is supported by the attached six-part testimony and Exhibits 37 through 61.

Citizens once again rely solely upon Dr. Hausler to support their case. His testimony consists of two new memoranda (Exhibits 38 and 39) and answers to 24 questions. The vast majority of the information provided by Dr. Hausler repeats arguments from Citizens' Direct Testimony submittal of July 20, 2007. AmerGen is not providing new testimony from its experts to respond to those recycled arguments. However, AmerGen is providing testimony to respond

[1] (Prehearing Conference Call Summary, Case Management Directives, and Final Scheduling Order) (April 17, 2007) (unpublished); (Ruling on Motions in Limine and Motion for Clarification) (August 9, 2007) (unpublished).

[2] "Citizens' Rebuttal Regarding Relicensing of Oyster Creek Nuclear Generating Station, Rebuttal Statement, Exhibits (August 17, 2006); "Prefiled Rebuttal Written Testimony of Dr. Rudolf H. Hausler Regarding Citizens' Drywell Contention" (August 16, 2007).



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to those few allegations that Dr. Hausler raises or clarifies for the first time on Rebuttal. As summarized below, and as demonstrated in the attached testimony, Citizens' arguments continue to deserve little consideration and should be given little if any weight.

By negating Citizens' arguments, this SurRebuttal continues to demonstrate that Citizens' contention is without merit, and that AmerGen's Aging Management Program ("AMP") for the sand bed region of the Oyster Creek Nuclear Generating Station ("OCNGS") drywell shell provides reasonable assurance that the drywell shell will continue to perform its intended functions throughout the period of extended operation in accordance with the current licensing basis ("CLB") as required by 10 C.F.R. § 54.29(a).

## II. SUMMARY OF AMERGEN'S SURREBUTTAL TESTIMONY

The parties' testimony is serving its purpose of narrowing and clarifying the issues that remain to be resolved at the hearing, as discussed in the following discussion of acceptance criteria, available margin, sources of water, epoxy coating system, and future corrosion.

### A. Acceptance Criteria

The testimony submitted to date shows that there is no dispute regarding the general buckling criterion (*i.e.*, uniform thickness of 0.736") or the pressure criterion (*i.e.*, 0.490" over an area that is 2.5" in diameter). The only dispute is over the local buckling criterion.

AmerGen has established, through the GE analyses performed in the early 1990s, a local buckling criterion consisting of the "tray" configuration shown in Applicants' Exhibit 11, "tak[ing] into account factors such as the location of the tray within the bay and configuration."[3] The center square foot of the tray is 0.536", with a transition back to 0.736" on all sides.

As is clearly reflected in Part 2 of the attached SurRebuttal Testimony and referenced exhibits, this local buckling criterion is part of the OCNGS CLB. The NRC Staff concurs that

[3] AmerGen Dir., Part 2, A.14.

this criterion is part of the CLB,[4] and that its review of AmerGen's License Renewal Application included "a very local criterion of 0.536 inch [as] discussed at SER pages 4-55 to 4-60."[5] As the federal regulator, the Staff's opinion should govern over the opinion of an anti-nuclear group.[6]

What appears to be the cause of Citizens' confusion is that instead of using this local buckling criterion, AmerGen has evaluated UT thickness data with more conservative, calculation–specific values such as 0.693" over a 6" x 6" area, etc.[7] This is akin to using an administrative limit, which does not alter the CLB.[8]

In their Rebuttal, Citizens do not accept Applicants' Exhibit 11 as the CLB local buckling criterion.[9] They attack the *derivation* of that criterion,[10] indirectly argue that it does not meet the ASME Code,[11] and because they cannot find a document to support that the criterion is part of the CLB,[12] they argue that it is not.[13] Citizens then suggest that the more conservative calculation–specific values that AmerGen has used in the various revisions to the 24 Calc (*e.g.*, 0.636" over a 12" x 12" area) ought to govern.[14] They have even asked the Board to set these more conservative values as the OCNGS CLB, something the Board does not have the authority

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4 *See e.g.* NRC Staff Response To AmerGen's Motion For Summary Disposition, Affidavit of Hansraj G. Ashar, ¶ 3 (Apr. 26, 2007) ("it is my opinion that AmerGen has developed three criteria related to acceptance of the shell thicknesses; . . . (2) a minimum locally thin thickness of 0.536 inch, in an area of one square foot, with a surrounding one foot transition area to 0.736 inch"); *see also* NRC Staff's Direct Testimony, A.9.

5 NRC Staff's Direct Testimony, A.9.

6 Since the start of this proceeding, Citizens have made their real intentions known by renaming themselves as "Stop the Relicensing of Oyster Creek" (STROC). *See e.g.* http://www.nirs.org/press/09-26-2006/1 (visited August 30, 2007).

7 AmerGen Dir., Part 2, A.19.

8 *Id.*, A.20. By analogy, the OCNGS Technical Specifications may require the drywell atmosphere during operation to contain less than 4% oxygen, but the plant may have a lower administrative limit of 2%. A 2% administrative limit would not alter the fact that 4% is the CLB.

9 Citizens' Rebuttal Statement at 8.

10 *See e.g., id.* at 5-9.

11 *See e.g.*, Dr. Hausler Rebuttal Testimony, A.6.

12 Citizens' Rebuttal Statement at 8.

13 *Id.*

14 Citizens' "Motion to Cross-Examine Mr. Tamburro," for example, is based on their insistence that 0.636" should be the appropriate local buckling criterion.

to do.[15]

AmerGen believes that the Board has prohibited Citizens from challenging the local buckling criterion (as well as the other established acceptance criteria) with the narrow exception that Citizens may present an argument that the "application of acceptance criteria and analytic methodology to the 2006 UT results was inconsistent with past practice."[16] Thus, at the hearing, the Board should address any of Citizens' arguments that the "application of acceptance criteria . . . to the 2006 UT results was inconsistent with past practice" and then proceed to the evaluation of bounding available margin using the OCNGS CLB acceptance criteria.

**B. Available Margin**

Here too the issues have been clarified and narrowed. It is undisputed that buckling, due to the weight of the water and equipment on the drywell shell during an earthquake that only occurs during refueling outage conditions, is the bounding scenario for failure of the drywell shell in the sand bed region.[17] AmerGen's position is that the bounding available margin for buckling at the start of the extended period of operations is 0.064".[18] This is based on the thinnest average of the 49 UT thickness measurements from internal grid 19A, which *in 1992* was 0.800", compared to the general buckling criterion of 0.736" (0.800"-0.736" = 0.064").[19]

What first remains in dispute is whether the internal UT data represent the bounding

[15] This criterion is part of the CLB, and that is not within the scope of the Board's jurisdiction in this license renewal proceeding. *See Florida Power & Light Co.* (Turkey Point Nuclear Generating Plant, Units 3 & 4), CLI-01-17, 54 N.R.C. 3, 8-9 (2001) ("the Commission did not believe it necessary or appropriate to throw open the full gamut of provisions in a plant's [CLB] to re-analysis during the license renewal review").

[16] Memorandum and Order (Denying AmerGen's Motion for Summary Disposition) at 8 (June 19, 2007) (unpublished).

[17] Failure of the drywell shell in the sand bed region due to internal pressure is not the bounding scenario. AmerGen Dir., Part 2, A.12. Dr. Hausler seems to not recognize this. *See e.g.* Citizens' Exh. 38 at 6 ("structures do not fail by averages....[they] fail where the deepest pit is located").

[18] AmerGen Dir., Part 3, A.5.

[19] AmerGen Reb., Part 3, A.26. The fact that external corrosion has been arrested is demonstrated by the averages from grid 19A that have varied little over time: 0.800" (1992), 0.806" (1994), 0.815" (1996) and 0.807" (2006). *Id.* at A.26.

conditions. Citizens argue they do not,[20] but do so by ignoring data that would disprove their case.[21] Part 3 of AmerGen's SurRebuttal Testimony supplements the record on this issue.

What also remains in dispute is the level of "confidence" in the internal data required by the ASME Code. AmerGen uses the average of these UT grid data (*i.e.*, the "sample average"). It does so because the sample average is what is important from a buckling perspective, not the extreme values.[22] Moreover, the nuclear industry standard is to use the average.[23]

Citizens argue that the level of confidence must be 95%. It is not clear what Citizens mean by 95%, as they define it in two, significantly different ways in their Rebuttal.[24] Dr. Hausler admits that 95% (whatever its definition) is not the industry standard; rather he believes that it *ought to be*.[25] Citizens provide no evidence that applicable nuclear industry Codes, guidance, or regulations require something other than the average.

The amount of uncertainty (*i.*e, systematic error) that should be taken into account is also in dispute. AmerGen does not subtract anything from the averages of the internal UT grid data to take into account systematic error because "[it] is negligible for sufficiently large numbers of measurements collected over time... [T]he more measurements you have . . . and the more times you collect those measurements, the less significant systematic error becomes."[26]

Citizens want to subtract 0.010" from the average of the internal UT data to account for

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[20] Citizens' Exhibit 12, at 3-4 (ignoring Bay 17 grid data); Citizens' Rebuttal, Exh. 39, at 14-15 (ignoring Bay 13 (Figures 1 and 2) and Bay 1 data (Figures 3 and 4)).

[21] *See* AmerGen SurReb., Part 3, A.5; AmerGen Reb., Part 3, A.25-29, A.32-33.

[22] AmerGen Reb., Part, A.2 ("[B]uckling is not a phenomenon that is dependent on very local thickness, but instead on the average thickness over a larger area. Thus, the averages of these data, not the thinnest extremes, are representative of each grid.").

[23] *Id.* at A.54 (discussing average readings used for evaluating Degraded Piping, Erosion-Corrosion (FAC) Prone Piping, Pressure Vessel Shells, and Tanks).

[24] AmerGen SurReb., Part 3, A.3-4.

[25] *See e.g.* Citizens' Exh. 38, at 8 ("there are currently no standards with respect to the certainty required").

[26] AmerGen Reb., Part 3, A.7.

systematic error.[27] They appear to ignore, among other things, the fact that instrument uncertainty is not in one direction, but is +/-. Therefore, averaging the data over 49 measurements makes the instrument uncertainty of +/- 0.010" insignificant.[28]

As for the external UT data, these were last collected in 2006 as single points from 106, mostly small (2" diameter) areas, most of which had been ground smooth to allow UT readings from the otherwise uneven, historically corroded exterior.[29] These points are biased thin compared to the rest of the drywell shell in the sand bed region as demonstrated by comparison to the internal UT grids[30] and by Dr. Hausler's own analysis.[31]

Any points that are thinner than 0.736" are compared to the local buckling criterion. Because this criterion is volumetric, it "is not exceeded when localized corrosion removes a couple or even tens of cubic inches from the tray. The entire tray, on average, needs to corrode away for that loss of metal to be significant from a buckling perspective . . ."[32] Also, the external single-point UT measurements "can tell you that you meet the applicable ASME Code, but not by how much. This is the case because there are an insufficient number of UT measurements over large areas to evaluate a representative average thickness over each area."[33]

Citizens evaluate these 106 external points using *extreme value* statistics.[34] There is no precedent for this other than Dr. Hausler's desire for it.[35] Again, the nuclear industry standard is

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[27] Citizens' Rebuttal Statement at 12 ("Subtracting an allowance of 0.01 inches for systematic error . . .").

[28] AmerGen Reb., Part 3, A.6-7.

[29] AmerGen Dir., Part 3, A.20 and A.41.

[30] AmerGen Reb., Part, A.42.

[31] Citizens' Exh. 12, at 4 (Dr. Hausler states that "the average outside measurements are significantly lower at comparable elevations [than the interior measurements]. This is probably because the choice of location for the external measurements was deliberately biased towards thin spots.").

[32] AmerGen Dir., Part 2, A.15.

[33] AmerGen Reb., Part 3, A.38.

[34] *See generally,* Citizens' Exh. 38 at 6-9.

[35] *Id.* at 8.

to use the average of the data from UT grids, not extreme value statistics on single points.[36]

Thus, the Board need only confirm that AmerGen's use of the average of the internal UT grid data, with no corrections for systematic error, is appropriate under the ASME Code. The Board need not delve into Dr. Hausler's computer modeling or other treatment of the UT data.

### C. Sources Of Water

The sources and timing of water potentially coming into contact with the external surface of the drywell shell in the sand bed region during the period of extended operation have also been clarified and narrowed for both outages and normal operation.

During outages, water can only come into contact with the external surface if: (a) the use of chillers inside the drywell cools the shell below the dew point temperature of the exterior air (causing condensation), or (b) the reactor cavity contains water and leakage exceeds the trough drain capacity, or the trough drain is blocked, and the water flows down to the sand bed region.

Condensation, while theoretically possible, was not observed during the most recent refueling outage. So, as explained below, condensation remains speculative. AmerGen's inspection of the trough drain[37] and sand bed drains[38] during each outage when the reactor cavity is filled would identify any water. Although the chance of water on the exterior drywell shell during such outages is low,[39] the Board could assume the presence of such water in order to streamline its inquiry at the hearing.[40]

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[36] Citizens also challenge the "Evaluation Thickness" mentioned in all of the revisions of the 24 Calc. (AmerGen's Exhibits 16 through 18). *See e.g.* Citizens' Exh. 13, at 6-7. AmerGen addressed Citizens' misunderstanding on this issue in its Rebuttal Testimony, Part 3, A.50 through A. 52 which Citizens could not have reviewed before they filed new testimony. Citizens' Exh. 39, at 15-16 (Dr. Hausler's rebuttal).

[37] Applicants' Exh. 10, at 9 (Item #13).

[38] AmerGen Reb., Part 4, A.19.

[39] Refueling outages occur every other year for up to 30 days. Forced outages when the reactor cavity must be filled with water are rare. AmerGen Dir., Part 1, A.17.

[40] *See* AmerGen Dir., Part 6, Q&A.14, which *assumes*, as a conservative analysis, that water—regardless of its source—is on the exterior surface of an *uncoated* drywell shell for 30 days, every other year.

The Board should conclude, however, that there is no water on the exterior drywell shell during normal plant operation. Condensation is physically impossible because the metal shell is hotter than the ambient air.[41] And there is no other known source of water other than the reactor cavity during outages. Citizens provide only speculation that other sources exist. AmerGen supplements the record on this issue in Part 4 of its SurRebuttal testimony.

### D. Epoxy Coating System

Of all the issues, this one has been clarified the most. AmerGen has provided testimony, by an eminently-qualified expert,[42] that the multi-layered epoxy coating was properly applied, is in good condition, and can serve its protective function through the period of extended operation. When the coating does begin to degrade, it will do so gradually, showing initial signs of degradation over a period of years. Moreover, these signs will be obvious to an ASME-qualified inspector. ASME Section XI, Subsection IWE, which is mandated by 10 C.F.R. § 50.55a, "recognizes that containments are coated and requires a visual inspection of the coating to identify ongoing corrosion of the containment vessel under the coating. NRC has endorsed these practices in the GALL Report (NUREG-1801, Vol. 2, Appendix xi.S8)."[43]

Citizens' proffered expert, whose has little or no experience with epoxy coating systems like the one covering the exterior drywell shell, has suggested that the coating could fail any at any time, would do so quickly, and that such failure would not be visible to an ASME-qualified inspector. This flies in the face of NRC regulations and guidance, and is based on an inappropriate analogy to "oil field experience" of "pressure drops," high temperatures, and

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[41] AmerGen Dir., Part 4, A.17.

[42] Mr. Jon Cavallo is, among other things, Chairman of the ASTM Committee D-33 (Protective Coating and Lining Work for Power Generation Facilities) and Chairman of the New England Chapter of the Society for Protective Coatings. *See* AmerGen Dir., Part 5, A.3.

[43] AmerGen Reb., Part 5, A.6

diffusion of corrosive gasses.[44] AmerGen's SurRebuttal in Part 5 supplements the record on these issues.

### E. **Future Corrosion**

This aspect of Citizens' case, in reality, remains the most speculative. In order to evaluate future corrosion of the exterior surface of the drywell shell in the sound bed region, one must first assume degradation of the epoxy coating system over a large enough area to implicate buckling,[45] and you need water in contact with that same large area for a significant period of time, without the water being detected.[46] Accordingly, AmerGen believes that future corrosion of a magnitude sufficient to remove 0.064" of metal from the entire shell, or in the precise grid location (grid 19A) where 0.064" remains, in the period between AmerGen's planned UT inspections, is entirely speculative. The conditions that supported high rates of corrosion no longer exist. AmerGen offered worst case and unrealistic corrosion rates of 0.039" and 0.017" for refueling outages to demonstrate that UT inspections every four years are adequate.

Similarly, Citizens have offered no corrosion rate that is realistic or expected for the external surface of the drywell in the sand bed region.[47] They argue that any future corrosion would occur at an exponential rate, but they do so with no legitimate support.[48]

As for the interior surface, it is either coated (above the concrete curb) or embedded in concrete (below the curb). Citizens have only challenged the embedded portion.

Citizens first alleged that 0.002" was an appropriate annual corrosion rate for this surface,

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44 Citizens' Exh. 39, at 17-18.

45 Localized coating degradation would implicate the pressure criterion (0.490") for which significantly more than 0.064" of margin remains at any UT location. AmerGen Dir., Part 3, A.32.

46 Even Dr. Hausler agrees that you need the confluence of "aerated aggressive water[,] . . .the coating has to have failed in some manner at the location where water is present [and] . . the corrosion has to occur at a location where the drywell has already been damaged." Citizens' Exh. 39, at 20.

47 *See e.g.*, Citizens' Rebuttal Statement at 23-24.

48 *See* AmerGen Reb., Part 6, A.5 through A.8 (confirming that Dr. Hausler is confusing "pitting" corrosion with "general" corrosion, and oil field conditions with exterior benign sand bed region conditions).

but in rebuttal state that it is as high as 0.010". Yet basic corrosion science,[49] and the observations of those engineers who looked at a recently exposed portion of the interior shell, demonstrate that only insignificant corrosion has occurred on this internal surface.[50] The water in contact with the interior shell is non-corrosive and is expected to remain so during the period of extended operation [51] Accordingly, the corrosion determined to have occurred between the UT readings taken in 1986 and 2006 must have resulted from historic corrosion of the *exterior* between 1986 and 1992. Part 6 of AmerGen's SurRebuttal Testimony supplements the record on this issue.

Respectfully submitted,

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Dated in Washington, D.C.
this 14th day of September 2007

[49] *Id.* at A.10.

[50] *Id.* at A.13.

[51] *Id.* at A.10 ("Water samples collected from the inside of the drywell shell during the 2006 outage were measured to have a pH of approximately 8.4 to 10.2 and low levels of chloride and sulfate, which is consistent with NRC [GALL] Report (Vol. 2, Rev. 1, at II A.1 through 5) and EPRI embedded steel guidelines for an environment that poses no aging management concerns.").

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| (License Renewal for Oyster Creek Nuclear Generating Station) | |

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

## I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles. The Board knows that a description of your current responsibilities, background and professional experience was provided in Part 1 of AmerGen's Pre-Filed Direct Testimony on July 20, 2007, so there is no need for you to repeat that information here.

A. 1: (JFO) My name is John F. O'Rourke. I am a Senior Project Manager, License Renewal, for Exelon, AmerGen Energy Company, LLC's ("AmerGen") parent company.

(FWP) My name is Frederick W. Polaski. I am the Manager of License Renewal for Exelon.

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

Q. 2: Would you please summarize the purpose of this SurRebuttal Testimony?

A. 2: (All) The purpose of this SurRebuttal Testimony is to respond to the information provided in Citizens' Rebuttal Statement Regarding Relicensing of Oyster Creek Nuclear Generating Station ("Citizens' Rebuttal Statement") and in the Pre-Filed Rebuttal Testimony of Dr. Rudolf H. Hausler, regarding the drywell physical structure and AmerGen's regulatory commitments.

## II. DRYWELL PHYSICAL STRUCTURE

Q. 3: Dr. Hausler alleges that "the exterior of the sandbed region . . . has very limited air exchange." (Citizens' Rebuttal Testimony, A.22). Citizens use this allegation to question Ed Hosterman's evaporation calculation in AmerGen's Direct Testimony, Part 6, A.19. Is Dr. Hausler correct?

A. 3: (All) No. Applicant's Exhibits 4 and 7 show that the drywell vents penetrate the concrete at the top of the sand bed region. The clearance between the concrete and the vents is greater than 3". There are 10 vents. Since the vent lines are approximately 4 feet in diameter, the gap between the vent and the concrete provides approximately 5.3 square feet for air flow in each bay. Additionally, many piping penetrations from the drywell have similar openings. Thus, there is substantial area for air flow through the sand bed region. In Part 6, Ed Hosterman will explain why air flow is expected through the sand bed region.

## III. REGULATORY COMMITMENTS

Q. 4: Citizens allege that "[t]he plant could be forced into an outage that requires the fuel cavity to be flooded before there is any chance to apply measures to mitigate leaks in the cavity liner" (Citizens' Rebuttal Statement, page 19; Hausler Rebuttal Testimony, A.23). How do you respond?

A. 4: (All) To clarify Part 1 of AmerGen's Direct Testimony, we did not state, nor did we imply, that strippable coating and metal tape would not be applied during a forced outage in which the reactor cavity is filled with water. We merely stated that, "[t]he reactor cavity may be required to be filled with water during a forced outage when the reactor vessel must be opened. Such outages are rare." AmerGen Dir. Part 1 A.17.

(MPG) My testimony summarized AmerGen's commitments to perform future actions related to drywell shell sand bed region corrosion control, including the commitment that "[a] strippable coating will be applied to the reactor cavity liner to prevent water intrusion between the drywell shield wall and the drywell shell *during periods when the reactor cavity is flooded*." (emphasis added.) Citizens then appear to have assumed that this commitment did not apply to forced outages, but Citizens are wrong. The commitment *does* extend to any non-refueling outage that would require the reactor cavity to be filled with water. The reason that the implementation schedule refers only to "refueling outages" is that we do not anticipate such an outage in the future.

Q.5: Does this conclude your testimony?

A. 5: (All) Yes.

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

John F. O'Rourke 9-12-07

John F. O'Rourke

Date

9/12/07

Frederick W. Polaski

Date

9-12-07

Michael P. Gallagher

Date

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# AMERGEN'S PRE-FILED SURREBUTTAL TESTIMONY PART 2 ACCEPTANCE CRITERIA

## I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles. The Board knows that a description of your current responsibilities, background and professional experience was provided in Parts 1 and 2 of AmerGen's Pre-Filed Direct Testimony on July 20, 2007, and in Part 2 of AmerGen's Pre-Filed Rebuttal Testimony on August 17, 2007, so there is no need for you to repeat that information here.

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

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

(AO) My name is Ahmed Ouaou, and I am a registered Professional Engineer specializing in civil structural design. I am an independent contractor.

Q. 2: Would you please summarize the purpose of your testimony?

A. 2: (All) The purpose of our testimony is to address the Atomic Safety and Licensing Board's ("Board") questions asked during the September 5, 2007 pre-hearing conference call regarding the established drywell shell thickness acceptance criteria for the sand bed region.

## II. RESPONSE TO BOARD QUESTIONS

Q. 3: Where can the Board find documentation that the three acceptance criteria—general and local buckling criteria, and the pressure criteria—are part of the CLB?

A. 3: (All). In general, the CLB as defined in 10 C.F.R. § 54.3 includes NRC approvals as well as design basis information contained in a plant's Updated Final Safety Analysis Report ("UFSAR"). The general buckling criterion (uniform thickness of 0.736") is part of the CLB as documented in the NRC's approval of this criterion in the April 1992 NRC Safety Evaluation attached as Applicant's Exhibit 37.

The local buckling criterion (0.536" in the tray configuration described in Part 2 of AmerGen's Direct Testimony and as shown in Applicant's Exhibit 11) and the pressure criterion (0.490" over circular areas of diameters up to 2.5") are part of the CLB as documented in the design basis information contained in the

OCNGS UFSAR. Relevant pages of the UFSAR are attached as Applicant's Exhibit 38. The Table of Contents to the UFSAR shows that Section 3.8 addresses the "DESIGN OF CATEGORY I STRUCTURES." Section 3.8.2.1 discusses the drywell shell as part of the containment, which is a Category I structure. Section 3.8.2.4.1, discusses the "Drywell." Section 3.8.2.5, entitled "Structural Acceptance Criteria" states, with italics added for emphasis:

> The Structural Acceptance Criteria relating the design and analysis results for the loads and load combinations given in Subsection 3.8.2.3 to the allowables, is presented in Subsection 3.8.2.4 and other referenced documents. The Basic Design phase of the Containment System is given in Subsection 3.8.2.4 *and the references listed in Subsection 3.8.6. These reference documents must be addressed to obtain complete information.*

It is clear, therefore, that the references in Section 3.8.6 provide the detailed information about the CLB acceptance criteria. Section 3.8.2.8, entitled "Drywell Corrosion" states:

> During 14R, UT measurements were taken from the outside of the drywell vessel in the sand bed region. Measurements were taken in each of the ten sand bed bays. The results of the inspection and the structural evaluation of the "as found" condition of the vessel is contained in Reference 44 [TDR-1108]. As documented in the TDR, the vessel was evaluated to conform to ASME code requirements given the deteriorated thickness condition."

Reference 44 is listed in Section 3.8.6 as the "GPUN Technical Data Report TDR-1108, 'Summary Report of Corrective Action Taken from Operating Cycle 12 through 14R', April 28, 1993", which is Applicant's Exhibit 27 ("TDR-1108"). Page 17 of TDR-1108 states:

Acceptance Criteria – Local Wall:

> If the thickness for the evaluation is less than 0.736 inches, then the use of specific GE studies is employed (Ref. 2.21). These studies contain analyses of the drywell using the pie slice finite element model, reducing the thickness by 0.200 inches in an area 12 x 12 inches in the sand bed region, tapering to original thickness over an additional 12 inches, located to result in the largest reduction possible. This location is selected at the point of maximum deflection of the eigen-vector shape associated with the lowest buckling load. The theoretical buckling load was reduced by 9.5 % from 6.41 to 5.56. Also, the surrounding areas of thickness greater than 0.736 inches is [*sic*] used to adjust the actual buckling values appropriately. Details are provided in the body of the calculation.

Note that the TDR's discussion of the local "wall" criterion includes only GE's modeling of 0.536" in the tray configuration as shown in Applicant's Exhibit 11. It does not include any other thickness or configuration.

As the quote above shows, the TDR identifies "(Ref. 2.21)" as the basis of its local buckling criterion. Reference 2.21, listed on page 5 of the TDR, is the "GE Letter Report, "Sandbed Local Thinning and Raising the Fixity Height Analyses (line Items 1 and 2 in Contract # PC-0391407)", dated December 11, 1992." This Letter Report contains GE's analysis of 0.536" in the tray configuration. It is attached as Applicant's Exhibit 39.

Page 18 of TDR-1108 discusses the pressure criterion, establishing the "required minimum thickness" for "Very Local Wall (2½ Inch Diameter)" to be 0.490".

In A.16 of AmerGen's Direct Testimony, we provided references for the Board to find how the CLB is carried through for License Renewal.

Q. 4: Is there another document that explains the technical basis for the established acceptance criteria and describes the modeling of the drywell used in the GE analyses upon which the acceptance criteria were established in the 1990s?

A. 4: (All) Yes. The presentations AmerGen provided to the Advisory Committee on Reactor Safeguards ("ACRS") License Renewal Subcommittee on January 18, 2007, and the full ACRS on February 1, 2007 are attached as Applicant's Exhibits 40 and 41. Slides 15 through 35 from the January 18 meeting describe the modeling of the drywell and buckling analysis in GE's December 11, 1992 Letter Report (Applicant's Exhibit 39). Slides 36 through 45 of Applicant's Exhibit 40 summarize General Electric's ASME Section VIII Stress Analysis. Similar information is also summarized in Applicant's Exhibit 3, beginning on page 6-7.

Applicant's Exhibits 40 and 41 [ACRS Presentations] also contain information regarding the drywell physical structure, the causes of historical corrosion in the sand bed region, the actions taken to arrest corrosion, and the actions taken to verify that corrosion has been arrested.

Q. 5: Do you have anything else to add?

A. 5: (MPG, PT) Yes. In our Direct Testimony, A.8, we stated that, with respect to the design and function of the drywell, "AmerGen complies with the [General Design Criteria] by meeting the applicable ASME Boiler and Pressure Vessel Code, standards, and specifications." The relevant portion of ASME Code Section III is attached as Applicant's Exhibit 42.

Q. 6: Does this conclude your testimony?

A. 6: (All) Yes.

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

| | |
|---|---|
| Michael P. Gallagher | 9-12-07 |
| Michael P. Gallagher | Date |
| | |
| Peter Tamburro | Date |
| Ahmed M Ouaou | 9/12/07 |
| Ahmed Ouaou | Date |

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

______________________________ ______________
Michael P. Gallagher Date

Pet T 9/13/07
Peter Tamburro Date

______________________________ ______________
Ahmed Ouaou Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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

| | | |
|---|---|---|
| In the Matter of: | ) | September 14, 2007 |
| AmerGen Energy Company, LLC | ) | Docket No. 50-219 |
| (License Renewal for Oyster Creek Nuclear Generating Station) | ) | |

# AMERGEN'S PRE-FILED SURREBUTTAL TESTIMONY PART 3 AVAILABLE MARGIN

## I. WITNESS BACKGROUND

Q. 1: Please provide the Licensing Board with your names and current titles. The Board knows that a description of your current responsibilities, background and professional experience was provided in Parts 1, 2 and 3 of AmerGen's Pre-Filed Direct Testimony on July 20, 2007, so there is no need for you to repeat that information here.

A. 1: (FWP) My name is Frederick W. Polaski. I am the Manager of License Renewal for Exelon.

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

(JA) My name is Julien Abramovici. I am a consultant with Enercon Services, Inc. located in Mt. Arlington, New Jersey, but formerly worked for the Oyster Creek Nuclear Generating Station ("OCNGS").

(PT) My name is Peter Tamburro. I am a Senior Mechanical Engineer in the OCNGS Engineering Department.

Q. 2: Please summarize the purpose of your testimony and overall conclusions.

A. 2: (All) The purpose of this SurRebuttal Testimony is to respond to the information provided in Citizens' Rebuttal Statement Regarding Relicensing of Oyster Creek Nuclear Generating Station ("Citizens' Rebuttal Statement") and in the Pre-Filed Rebuttal Testimony of Dr. Rudolf H. Hausler, regarding the topic of available margin. Our overall conclusions, as explained below, are that Dr. Hausler and Citizens have presented no new information that would call into question our previous testimony on available margin.

Q. 3: In their Rebuttal Statement, on page 3, Citizens appear to argue that "reasonable assurance" requires 95% confidence. What is your response to this argument?

A. 3: (All) Citizens have never clearly explained what they mean by the term "95% confidence." In a statistical analysis of UT thickness data, this term could describe one of two distinct concepts. It is possible to calculate a lower and upper 95% confidence limit about the *mean*, *i.e.*, sample average, or a lower and upper 95% confidence limit for the *data*. The significant difference between these two confidence limits is shown in Applicant's Exhibit 43, which displays the Bay 19 internal UT grid measurements from 1992.

In that Exhibit, the short dashed (blue) vertical lines indicate the $\pm 3\sigma$, $\pm 2\sigma$, and $\pm 1\sigma$ values for measurements which have an average of 0.800" and a standard deviation of about 0.059". The long dashed (red) lines are the 95% confidence limits computed for the mean ($\mu$) using the student t distribution with 44 degrees of freedom. The difference between the actual measurements and the confidence limits for the mean ($\mu$) are striking. This is because the distribution for the measurements (*i.e.*, the 49 points) and the distribution for the mean ($\mu$) are actually different. The distribution for the measurements is "normal" whereas the distribution for the mean ($\mu$) is the student t distribution. Consequently, describing the measurements and the confidence interval for the mean ($\mu$) must be done precisely and carefully.

Q. 4: How do Citizens use the term "95% confidence"?

A. 4: (All) Citizens' Statement and Dr. Hausler's testimony suggests that Citizens are interested in the 95% confidence limit *for the data*. Examples of this argument include:

- Citizens' Exh. 39, page 6 ("the 95% confidence limits embrace 95% of all data . . . defined as the mean of the data +/- approximately two (2) standard deviations");
- Citizens' Rebuttal Statement, page 11 ("AmerGen bears the burden of evaluating the current margins using the estimated *lower* 95% confidence limits for the various required parameters...");

- Citizens' Rebuttal Statement, page 14 ("the external data do not comply with the acceptance criteria at the 95% confidence level if the *thinnest* measurements obtained are used.");
- Citizens' Rebuttal Statement, page 16 ("if the *lower* 95% confidence limit was compared to the acceptance criterion");
- Citizens' Rebuttal Statement, page 18 ("the lower 95% confidence limit for the thickness of certain parts of the drywell shell is below [the pressure] criterion" of 0.490"");
- Citizens' Exh. 38, page 6 ("structures do not fail by averages....[they] fail where the deepest pit is located").

Q. 5: Is it appropriate to analyze UT measurement data in terms of a 95% confidence level for the data?

A. 5: (All) No. Citizens' argument that the *internal* UT data should be analyzed using a 95% confidence limit for the data is particularly absurd. This would result in an analysis that focuses on the thinnest UT data points from among the 49 internal UT measurements in each grid, effectively ignoring 48 other known data points from the same 6" x 6" grid. This approach has no scientific basis. As Dr. Harlow stated in his Rebuttal testimony (Part 3, A.22):

> AmerGen is primarily interested in the data within a grid which are between ± two sigma about the sample average because this region accounts for 95% of normally distributed data. If there is relatively little scatter in these data, which has been demonstrated elsewhere, so that they are also reasonably close to the sample average, then the sample *average* is the quantity that should be used in comparison to the general buckling criterion. The 5% of the data outside ± two sigma about the sample average pose no threat to buckling; however, these data are considered relative to the pressure criterion.

Q. 6: But AmerGen uses only the average of the 49 points from an internal grid. Why doesn't AmerGen evaluate the internal UT grid data using a 95% confidence interval about the mean?

A. 6: (PT, JA, DGH) AmerGen *does evaluate* the 95% confidence interval of the sample average for each internal grid after each inspection to understand the variability of each calculated average. (Applicant's Exh. 20 (41 Calc)). The variability of the sample average demonstrates, however, that the calculated averages over time are well behaved and repeatable. There is an equal probability that the true mean is either greater or less than the calculated sample average within the 95% confidence interval because the internal grid data are normally distributed. Based on this calculation, and based on the Grand Standard Error calculation discussed in AmerGen's Rebuttal Testimony, A.17, it is concluded, therefore, that the average is the best representation of the thickness over the inspected area. Therefore, AmerGen uses the sample average to identify the available margin, without adjustment to include the lower 95% confidence limit.

Q. 7: Citizens allege that AmerGen is being inconsistent in that it evaluated future corrosion rates using a 95% confidence lower limit about the mean, but does not do that to evaluate the mean to identify the available margin. What is your response?

A. 7: (PT, JA, FWP) As described above in A.6, there is no discrepancy because this is a conservative approach.

Q. 8: Citizens argue that AmerGen has "erroneously claimed it has actually calculated the minimum margins based on the lower 95% confidence limit." (Citizens'

Rebuttal Statement, page 4 (citing Applicant's Exh. 3 at 6-15 to 6-16; Applicant's Exh. 12 at 13-14.)). What is your response?

A. 8: (PT, FWP) Citizens have identified an error in AmerGen's documents. The cited margins are not calculated with 95% confidence. Citizens' first citation is to Applicant's Exhibit 3, pages 6-15 and 6-16, which are two tables from a submittal to the Advisory Committee on Reactor Safeguards ("ACRS"), with titles that use the term "95% Confidence Level Average Thickness." These titles are based on the second document which Citizens cite (Applicant's Exhibit 12 (pages 13-14)), the LRA Supplement submitted to the NRC on December 3, 2006, which states, for example, that "Analysis of the 2006 UT data, at the 19 grid locations, indicates that the minimum 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."

The statement is not correct as written. The values in the tables in Applicant's Exhibit 3, pages 6-15 and 6-16 are simply the calculated averages for each grid. This table does not report the upper or lower 95% confidence limits or the 95% confidence interval. The statement is correct if "95% confidence level" is deleted in both locations. As discussed in A.6, above, the 95% confidence lower limit was evaluated for the sample averages, so this only a cosmetic error.

Q. 9: Citizens state that "AmerGen argues that the external measurements are not accurate enough to allow margins to be determined, but AmerGen has also maintained that it can use those same measurements to determine whether the shell complies with the acceptance criteria. This position is unsustainable." (Citizens' Rebuttal Statement, page 10). Do you agree?

A. 9: (PT, FWP, JA) No. First, AmerGen does *not* claim that the "external measurements are not accurate enough." The measurements are accurate over the very small area covered by the UT probe (less than 3/8" in diameter). Buckling, however, is a phenomenon that is implicated here when metal is lost over a significant area. The volumetric nature of the local buckling criterion is based on this principle: "[t]he entire [124.8 cubic inch] tray, on average, needs to corrode away for that loss of metal to be significant from a buckling perspective and to exceed the local buckling criterion." (AmerGen Dir. Part 3, A.15). Thus any calculation of margin to the local buckling criterion must be expressed in cubic inches, not in inches, and there simply are not sufficient external UT data points to calculate such a volumetric margin.

As we explained in our Direct Testimony, A.29 and A.30, in the "24 Calc." external single point UT data are averaged as a conservative method of "demonstrating compliance with the general buckling acceptance criterion." It is simply not realistic to average these data for the purpose of quantifying the actual estimated available margin.

As explained in our direct testimony, in the 24 Calc. AmerGen uses conservative assumptions to demonstrate compliance with the ASME Code. These assumptions would not be appropriate for quantifying the actual available margin. "In other words, [the 24 Calc.] confirms that you meet the applicable ASME Code, but not by how much." (AmerGen Dir. Part 3, A.29).

Q. 10: Please respond to Dr. Hausler's statement that, "[a] number of AmerGen evaluations of 'representative thickness' admit plainly that the internal grid data in certain Bays is not representative of the true mean thickness of the Bay because of the pattern of corrosion." (Citizens' Rebuttal Statement, page 12, citing Citizens' Exh. 45 at 3 (discussing this issue in Bay 1); Exh. 46 at OCLR29744-5 (discussing Bays 1, 3, 7, and 15).

A. 10: (PT, FWP) Dr. Hausler is taking these documents out of context. Citizens' Exhibit 45 and 46 are documents AmerGen used to develop inputs to a future containment analysis. This analysis is a commitment AmerGen made as documented in Exhibit 10, page 11 of 13 (Commitment #18). The inputs for thickness were selected to establish a thickness profile for the sand bed that was representative but appropriately conservative in representing the current thickness conditions. In general, internal grid thickness measurements were used. When appropriate, more conservative thicknesses were used such as adjacent bay thickness or UT data from the trenches. In no cases were external UT measurements used since they are not representative of the average thickness in the bays since they were biased as the thinnest points in the bay.

Q. 11: Citizens allege that Applicant's Exh. 16, pages 34 and 92-93 "shows a 3 foot by 3 foot area that is less than 0.736 inches in average thickness." (Citizens' Rebuttal Statement, page 16). Is this correct?

A. 11: (PT, JA, FWP) No. Dr. Hausler's statement is incorrect and misleading. Revision 2 of the 24 Calc. (Applicant's Exh. 16 at 92-93) concludes that there is a 3' by 3' area in Bay 19 that is "*at least* 0.720" thick." This is conservatively based on only *two of the lowest* external points in this 3' by 3' area. The calculation does *not* conclude that this area is on average 0.720" thick. First, the external point measurements are taken at locations that "are biased thin compared to their surroundings," as stated in AmerGen Dir. Part 3, A.42. So even without more information, we know that the area in question is much thicker. Second, there is a third external point within the 3' by 3' area, between the two thinner points, that measured 0.736". Third, internal grids 19B and 19C coincide with the same 3' by 3' area and they have average thicknesses of 0.848" and 0.824", respectively. These data conclusively demonstrate that the area in question is thicker.

Finally, contrary to Citizens' implication, the 3' by 3' area is compared to the local buckling criterion, not the 0.736" general buckling criterion, so even if the area was, on average, 0.720" thick, it would not be significant from a buckling perspective.

Q. 12: In the previous Answer, you stated that the internal grids 19B and 19C coincide with specific external areas. How do you know that?

A. 12: (PT, FWP) We first relied upon Applicant's Exhibit 28, which generally shows the overlap of the internal grids and trench UT locations with the external data points. That Exhibit, however, is not to scale and shows all ten bays on a single sheet of paper. We then prepared similar maps for the bays identified as a concern by Citizens (Bays 1, 13, 17, and 19). Those maps, which are an excellent representation of the location of the UT measurement locations and are essentially to scale, are provided as Applicant's Exhibit 44.

Q. 13: In Dr. Hausler's Rebuttal Testimony, A.8 (referencing Citizens' Exh. 38), he states that he "refined [his] calculation of the sample standard deviation." How has Dr. Hausler "refined his calculations?

A. 13: (DGH) It is unclear exactly how Dr. Hausler has "refined" his calculation. In footnote 4 of Exhibit 38, he appears to provide more detail: "[t]he standard deviations derived from repeat measurements shown in Table 1 differ slightly from those previously presented, because I have used a more rigorous calculation method than previously. [sic]" This statement makes very little sense, unless Dr. Hausler is correcting mathematical errors. The standard deviation for a set of measurements is defined as follows:

$$s = \sqrt{\sum_{k=1}^{n} (x_k - \bar{x})^2 / (n-1)}.$$

All standard software and all calculators use this as the definition for standard deviation. Spreadsheets have its computation built into the computation library so that its computation is simple. I cannot imagine what Dr. Hausler means by "a more rigorous calculation method than previously" used.

Q. 14: In Dr. Hausler's Rebuttal Testimony, A.11, he states: "the 2006 measurements showed that the shell is now approximately 2 to 3% thinner overall than measured in 1992." What is the basis for this statement?

A. 14: (PT, JA, FWP) We could not identify any basis for Dr. Hausler's statement other than the statement "[m]y analysis of the data."

Q. 15: Do you agree with Dr. Hausler's statement?

A. 15: (PT, JA, FWP) No. Visual observations and the results of the UT grid readings over time demonstrate that corrosion has been arrested.

Q. 16: In Dr. Hausler's Rebuttal Testimony, A.14, Citizens quote an OCNGS document from 1993, attached as Citizens' Exhibit 44 (on page 2) as follows: "I could not determine visually which of the thin spots are the thinnest." Does this quote accurately reflect this document?

A. 16: (PT, FWP) No, the quote is egregiously taken out of context. The full quotation, with italics for emphasis, is:

> In addition to the dimples, there are spots that appear to be thinner than the general area. The dimples in the surface occur in these thin spots to the same degree as in the rest of the corroded portion of the shell. The "thin" spots are typically a foot to 18" in diameter and probably comprise about 20% of the corroded area. In general, except in Bay 13, the thin spots are not readily apparent. Therefore, a more detailed characterization is difficult for the other bays . . . . I could not determine visually which of the thin spots are the thinnest. However, due to the small differences between the "thick" areas and the "thin" areas, and the amount of metal removed in preparation for the UT measurements, *it is highly likely that the thickness readings reported in the UT measurements encompass the thinnest spots in the shell.*

Thus, Citizens' Exhibit does not support their conclusion. Instead, it supports the opposite conclusion, that the external points are biased thin.

Q. 17: In Citizens' Rebuttal, A.16, Dr. Hausler discusses the alleged "overgrinding" of metal at the external UT locations. In this discussion, he acknowledges that the curvature of the prepared area created an air gap on the exterior shell that may have created a bias in the 1992 UT data. He then argues that, "If this bias indeed exists, the only explanation offered assumes that the measured points were not overground." What is your response to this argument?

A. 17: (PT) We have previously testified that "additional good metal" may have been removed at some of the external data points, leading to some additional conservatism in AmerGen's calculations. (AmerGen Dir. at A.42). Dr. Hausler's statement assumes that the metal removal process would have eliminated any curvature in the prepared surface, thus eliminating the bias. This is wrong. Ultimately, the question of whether these areas were "overground" or not is significantly less important than the fact that they are biased thin when compared to the rest of the shell. So we believe that Dr. Hausler's argument is a red herring.

Q. 18: In Dr. Hausler's Rebuttal Testimony, A.19, he claims that it was "unlikely" that the corrosion occurred between 1986 and 1992 "because Bays 5 & 17 are the least corroded Bays and the estimated corrosion rate in Bay 17 was not significant or was very small (no corrosion rate was even estimated for Bay 5)." He does this in an effort to show that significant corrosion is occurring or can occur on the interior embedded surface of the drywell shell in the sand bed region. Do you agree?

A. 18: (PT, FWP) No. First, with respect to Bay 17, this trench was selected because it was representative of significant external corrosion, so Dr. Hausler is simply wrong. Data from bay 17 show significant external metal loss between 1986 and 1992. For example, as shown in Applicant's Exhibit 3, page 6-15, the average measurement in grid #17D was 0.922" in February 1987 and 0.817" during the

1992 refueling outage; the average thickness in grid #17A bottom was 0.999" in December 1986 and 0.941" during the 1992 refueling outage.

Second, with respect to Bay 5, Dr. Hausler's speculation of significant interior corrosion is also contradicted by all of the available evidence. We know from Barry Gordon's Rebuttal Testimony that any corrosion from the interior would be expected to be "vanishingly small and of no engineering concern." (AmerGen Reb. Part 6, A.10). We also know from visual inspections of Bay 5 following sand removal that some exterior corrosion was experienced prior to the 1992 refueling outage. This is documented in Applicant's Exhibit 27, page 27 (the physical condition of bay 5 "was very similar to [the corrosion in] bay 3"). We know that the interior of the trench was observed visually during the 2006 refueling outage, and the surface was smooth with only minor surface corrosion. And we know from AmerGen's Direct and Rebuttal Testimony, Part 5, that the epoxy coating is intact with no signs of deterioration, so we know that corrosion from the exterior has been arrested since 1992.

Q. 19: In Citizens' Exhibit 38, page 3, Dr. Hausler states that "[d]uplicate & triplicate measurements were made externally in some bays" in 2006. Is this correct?

A. 19: (All) No. In some cases two and three UT thickness values were recorded at some external locations. However, the multiple measurements were *not* taken at the same exact points. They were taken about ¼-inch around the measurement points, but within the prepared area. This is documented, for example, in the 24 Calc., Applicant's Exhibit 16, on pages 171 and 176, which are the data sheets for bays 5 and 15. In all cases the 24 Calc. used the thinnest value recorded for each location.

But Dr. Hausler then uses these "duplicate and triplicate" measurements to generate an uncertainty value for the external data: "It was then possible to estimate the measuring error form [sic] these repeated measurements." Dr. Hausler's assumption that the differences in these values can be attributed to the "error in measurement only" is wrong because these data are not from the exact same points. So Dr. Hausler's calculations are statistically improper.

Q. 20: Do you have anything else to add?

A. 20: (PT, JA) Yes. In our Rebuttal Testimony, A.54, we referenced ASME Code Case N513, NRC Bulletin 87-01, "Thinning of Pipe Wall in Nuclear Power Plants," NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" ASME Code Section XI, and API 653 in our answer to the Board's question on the statistical analysis of UT thickness measurements. Relevant portions of these documents are attached as Applicant's Exhibits 45 through 49.

Q. 21: Does this conclude your testimony?

A. 21: (All) Yes.

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

| | |
|---|---|
| [signature] | 9/12/07 |
| Frederick W. Polaski | Date |
| | |
| Dr. David Gary Harlow | Date |
| | |
| Julien Abramovici | Date |
| | |
| Peter Tamburro | Date |

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

Frederick W. Polaski — Date

David Gary Harlow

Dr. David Gary Harlow — 9/13/07 Date

Julien Abramovici — Date

Peter Tamburro — Date

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

| | |
|---|---|
| Frederick W. Polaski | Date |
| Dr. David Gary Harlow | Date |
| Julien Abramovici | 9-13-07<br>Date |
| Peter Tamburro | Date |

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

Frederick W. Polaski — Date

Dr. David Gary Harlow — Date

Julien Abramovici — Date

Peter Tamburro — Date 9/13/07

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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

| | | |
|---|---|---|
| In the Matter of: | ) | September 14, 2007 |
| AmerGen Energy Company, LLC | ) | |
| | ) | Docket No. 50-219 |
| (License Renewal for Oyster Creek Nuclear Generating Station) | ) | |

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

## I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles. The Board knows that a description of your current responsibilities, background and professional experience was provided in Parts 1 and 4 of AmerGen's Pre-Filed Direct Testimony on July 20, 2007, so there is no need for you to repeat that information here.

A. 1: (JFO) My name is John F. O'Rourke. I am a Senior Project Manager, License Renewal, for Exelon, AmerGen Energy Company, LLC's ("AmerGen") parent company.

(AO) My name is Ahmed Ouaou. I am a registered Professional Engineer specializing in civil/structural design and an independent contractor.

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

## II. KNOWN SOURCES OF WATER IN THE SAND BED REGION

Q. 2: Please summarize the purpose of this SurRebuttal Testimony and your conclusions.

A. 2: (All) The purpose of this SurRebuttal Testimony is to respond to the information provided in Citizens' Rebuttal Statement Regarding Relicensing of Oyster Creek Nuclear Generating Station ("Citizens' Rebuttal Statement") and in the Pre-Filed Rebuttal Testimony of Dr. Rudolf H. Hausler, regarding the sources of water in the sand bed region. Our overall conclusions, as explained below, are that Dr. Hausler and Citizens have presented no new information that would call into question our previous testimony on the sources of water in the sand bed region.

Q. 3: Citizens have alleged that the reactor cavity concrete "trough is still subject to high temperatures that could cause the concrete to deteriorate and the condition of the trough was seen to be far from ideal in the most recent outage." (Citizens' Rebuttal Statement, page 20 (citing Citizens' Exhs. 48 & 49)). How do you respond to this allegation?

A. 3: (All) Citizens' Exhibits provide no support for their conclusion that the condition of the trough was seen to be far from ideal in the "most recent" outage. The exhibits are from 1986 and 1996, not 2006. And there was no evidence of any defects in the trough drain during the 2006 refueling outage. The trough functioned as designed by conveying any water to the trough drain and, thereby, preventing water from entering the external sand bed region.

Q. 4: Citizens allege that "[t]he plant could be forced into an outage that requires the fuel cavity to be flooded before there is any chance to apply measures to mitigate leaks in the cavity liner." (Citizens' Rebuttal Statement, page 19; Rebuttal Testimony, A.23, citing AmerGen Dir. Part 1, A.17). How do you respond to this allegation?

A. 4: (AO, JFO, FHR) As stated in Part 1 of this SurRebuttal Testimony, A.4, AmerGen has committed to apply a strippable coating "to the reactor cavity liner to prevent water intrusion between the drywell shield wall and the drywell shell *during periods when the reactor cavity is flooded.*" This includes forced outages. Further, as stated in AmerGen's Direct Testimony, Part 4, A.6, "forced outages when the reactor cavity had to be filled with water are rare, and OCNGS has not experienced such an outage since at least 1990."

Q. 5: Citizens allege that AmerGen has failed to account "for other forced outages that could lead to condensation on the exterior of the drywell surface." (Citizens' Rebuttal Statement, page 23; Rebuttal Testimony, A.23). How do you respond?

A. 5: (All) Citizens are wrong. Mr. Gordon's analysis assumed that the exterior surface of an uncoated drywell shell is exposed to water for 30 days every two years. The average duration of OCNGS's past four refueling outages, since AmerGen took over management, however, has been 26 days. Thus, Mr. Gordon's analysis contains margin to account for potential drywell entry time during forced outages during which condensation is assumed to be present.

Nevertheless, such condensation remains highly speculative. Citizens fail to recognize that, as described in AmerGen's Direct Testimony, Part 4, A.16, there was no evidence of condensation on the exterior of the drywell shell in the sand bed region at any time during the 2006 outage, even while the drywell chillers were in operation. Thus, even if there is a theoretical potential for condensation, there is no evidence that it has actually taken place. Citizens present no evidence that it has, or even that it is likely. As a result, "the potential for condensation is entirely speculative." (AmerGen Dir. Part 4, A.17).

Q. 6: Do you have anything else to add?

A. 6: (All) Yes. In our Direct Testimony, A.9, we discussed the results of the reactor cavity liner leakage inspections during the 2006 refueling outage, and in our Direct Testimony, A.10, and Rebuttal Testimony, A.6, we discussed the results of the daily and quarterly poly bottle inspections from the Torus Room since March 2006. Relevant portions of the completion documentation for these inspections are attached as Applicant's Exhibits 50 through 56.

Q. 7: Does this conclude your testimony?

A. 7: (All) Yes.

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

John F. O'Rourke 9-12-2007

John F. O'Rourke Date

Ahmed M Ouaou 9/12/2007

Ahmed Ouaou Date

Francis H. Ray Date

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

John F. O'Rourke — Date

Ahmed Ouaou — Date

F. Hari Ray

Francis H. Ray — 9/12/2007 Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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

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| In the Matter of: | ) | September 14, 2007 |
| AmerGen Energy Company, LLC | ) | |
| (License Renewal for Oyster Creek Nuclear Generating Station) | ) | Docket No. 50-219 |

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

## I. WITNESS BACKGROUND

Q. 1: Please state your name and current title. The Board knows that a description of your current responsibilities, background and professional experience was provided in Part 5 of AmerGen's pre-filed Direct Testimony on July 20, 2007, so there is no need for you to repeat that information here.

A. 1: (JRC) My name is Jon R. Cavallo. I am Vice President of Corrosion Control Consultants and Labs, Inc., and Vice-Chairman of Sponge-Jet, Inc.

Q. 2: Please summarize the purpose of this SurRebuttal Testimony and your overall conclusions.

A. 2: (JRC) The purpose of this SurRebuttal Testimony is to respond to the information provided in Citizens' Rebuttal Statement Regarding Relicensing of Oyster Creek Nuclear Generating Station ("Citizens' Rebuttal Statement") and in the Pre-Filed Rebuttal Testimony of Dr. Rudolf H. Hausler, regarding the epoxy coating system installed on the exterior of the OCNGS drywell shell in the sand bed region. My overall conclusions are that Citizens have presented no new information that would call into question my previous conclusion that the epoxy coating system should preclude further corrosion of the exterior drywell shell in the sand bed region, and that Dr. Hausler's expertise appears to be fundamentally inapplicable to that epoxy coating system.

## II. RESPONSE TO CITIZENS' REBUTTAL

Q. 3: Do you agree with Dr. Hausler's statement that "tests with the wet sponge technique . . . as standardized by NACE are quite simple to carry out and it is unclear why these tests were not done."? (Citizens' Exh. 39, page 17).

A. 3: (JRC) No, I do not. Discontinuity (holiday) testing using the wet sponge technique is not required for a coating system in atmospheric service when benign exposure conditions exist, such as in the sand bed region of OCNGS. The NACE standard that Dr. Hausler refers to is SP0188-2006, "Standard Practice / Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates." In the Forward to the NACE standard, the following statement appears, with italics added for emphasis:

> This standard was originally prepared in 1988 by Task Group T-6A-37, a component of Unit Committee T-6A on *Coating and Lining Materials for Immersion Service*. It

> was reaffirmed in 1990, revised in 1999, and reaffirmed in 2006 by Specific Technology Group (STG) 03. This standard is issued by NACE International under the auspices of STG 03 on *Protective Coatings and Linings: Immersion and Buried.*

It is evident from this Forward that discontinuity (holiday) testing using the wet sponge technique is intended for use in aggressive corrosion environments, such as encountered in buried or underwater service, and not for benign atmospheric conditions such as those found in the OCNGS sand bed region.

Q. 4: Dr. Hausler has stated that "Residual stresses . . . can lead to spontaneous cracking, particularly under conditions of constant vibration and fatigue and elevated temperature." (Citizens' Exh. 39, page 17). What is your response to this statement?

A. 4: (JRC) Dr. Hausler's statement demonstrates a lack of understanding of the exposure conditions of the three-coat epoxy coating system applied to the drywell exterior in the OCNGS sand bed region. The exterior surface of the OCNGS drywell in the sand bed region is not subject to vibration or flexure (fatigue) during normal plant operations, and as stated in AmerGen's Direct Testimony, Part 6, A.19, the reasonable operating internal temperature in the sand bed region of 130°F is far below the maximum allowable continuous temperature limit of the three-coat epoxy coating system (250°F). Applicant's Exhibit 35 (Devran 184 data sheet).

Q. 5: Dr. Hausler also warns that "epoxy coatings are subject to spontaneous delamination as a consequence of abrupt pressure drops." (Citizens' Exh. 39 at 17). Does this warning apply to the coating on the exterior sand bed region?

A. 5: (JRC) No, it does not. The only pressure changes that will be encountered in the OCNGS exterior sand bed region will be as a result of changes in environmental conditions within the reactor building that would result in slow increases and decreases of pressure. Small, slow fluctuations in atmospheric pressure will not cause the "spontaneous delamination" phenomenon proposed by Dr. Hausler.

Q. 6: Please respond to Dr. Hausler's allegation in A.18 that "areas of the shell in the sandbed region were not coated with epoxy because they are inaccessible."

A. 6: (JRC) Citizens' A.18 makes clear that Dr. Hausler bases his allegation on two documents: Citizens' Exhibits 40 and 41. As discussed below, neither of these documents supports Dr. Hausler's allegation.

Exhibit 40 is a November 2006 AmerGen e-mail discussing the *possibility* that parts of the exterior drywell shell in the sand bed region are not coated with epoxy. It states that "[a]ssuming there are areas that could not be accessed and/or protective coating applied. . ." And its discussion is based entirely on a historical document that pre-dated the cleaning and coating of the exterior shell. Therefore, this historical source cannot possibly provide reliable evidence of whether areas of the shell were not coated because it was written before the coating was applied.

Exhibit 41 also does not support Dr. Hausler's allegation, for the same reasons as Exhibit 40. Exhibit 41 is a two-page excerpt from a GPUN evaluation written in December 1992. The evaluation similarly talks about the coating of the exterior of the drywell shell in the future tense, for example: "some patches of the drywell exterior may be left uncleaned and/or uncoated."

The workers who inspected the external coating in all ten bays during the 2006 refueling outage confirmed that all of the areas were coated. These actual visual observations clearly trump Dr. Hausler's speculation, which is based on documents that pre-date application of the epoxy coating.

## II. DR. HAUSLER'S EXPERTISE

Q. 7: Are you aware of any new information about Dr. Hausler's expertise with regard to the OCNGS epoxy coating system?

A. 7: (JRC) Yes. Citizens submitted additional information about Dr. Hausler's qualifications and the papers he has authored in their response to AmerGen's Motion in Limine of July 27. Dr. Hausler identified some articles that are attached as Applicant's Exhibit 57 (R. H. Hausler, et al., "Corrosion Management in the Arun Oil Field," 1996), Applicant's Exhibit 58 (R.H. Hausler, et al., "Development of a Corrosion Inhibition Model I: Laboratory Studies," 1999), and Applicant's Exhibit 59 (R.H. Hausler, et al., "Development of a Corrosion Inhibition Model II: Verification of Model by Continuous Corrosion Rate Measurements Under Flowing Conditions with a Novel Downhole Tool," 1999). I was not able to retrieve these documents in time to incorporate any comments on them into AmerGen's Rebuttal Testimony. I have now reviewed these papers and the topics discussed in them confirm that Dr. Hausler's expertise is primarily in oil field applications that have very little in common with OCNGS epoxy coating system and the benign sand bed region environment that the epoxy coating system is exposed to.

In closing, my review has identified no evidence that Dr. Hausler serves on any NACE or EPRI or other technical committees, or has any experience related to coatings in atmospheric service.

Q. 8: Does this conclude your testimony?

A. 8: (JRC) Yes.

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

Jon R. Cavallo

Jon R. Cavallo

13 September 2007

Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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

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| In the Matter of: | ) | September 14, 2007 |
| AmerGen Energy Company, LLC | ) | |
| (License Renewal for Oyster Creek Nuclear Generating Station) | ) | Docket No. 50-219 |

# AMERGEN'S PRE-FILED SURREBUTTAL TESTIMONY PART 6 FUTURE CORROSION

## I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles. The Board knows that a description of your current responsibilities, background and professional experience was provided in Parts 1, 2 and 6 of AmerGen's Pre-Filed Direct Testimony on July 20, 2007, so there is no need for you to repeat that information here.

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

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

Q. 2: Please summarize the purpose of this SurRebuttal Testimony and your overall conclusions.

A. 2: (All) The purpose of this SurRebuttal Testimony is to respond to the information provided in Citizens' Rebuttal Statement Regarding Relicensing of Oyster Creek Nuclear Generating Station ("Citizens' Rebuttal Statement") and in the Pre-Filed Rebuttal Testimony of Dr. Rudolf H. Hausler, regarding the potential for future corrosion of the exterior drywell shell in the sand bed region. Our overall conclusions are that Dr. Hausler's Testimony, once again, is based on inapplicable analyses and mistaken assumptions, and that Dr. Hausler's expertise appears to be fundamentally inapplicable to the actual conditions of the drywell shell in the sand bed region.

## II. POTENTIAL CORROSION RATE

Q. 3: Dr. Hausler has opined that sand bed region "corrosion could be as rapid as it was in the presence of the sand." (Citizens' Exh. 39, page 17). Do you agree with this statement?

A. 3: (BMG) No. There are three main reasons why this would not be the case. First, the drywell corrosion mitigation steps as described throughout AmerGen's testimony, such as applying a strippable coating to the reactor cavity liner, removing the sand, clearing the drains, and installing a three-layer epoxy coating system on the exterior drywell shell surface, will prevent this high rate of corrosion.

Second, as described in my Rebuttal Testimony, A.14, due to the above mitigation steps, the expected time of wetness, $T_w$, on the drywell shell has been dramatically reduced to the point where the coated drywell exterior could be dry all of the time. If there is no moisture, there is no corrosion.

Third, as described in my Rebuttal Testimony, A.7, the rate of general corrosion decreases with time due to the formation of corrosion products/films on the metal surface. Therefore, any subsequent corrosion on a freshly-wetted, previously corroded surface would not corrode at the same rate as measured previously. General corrosion rates typically decrease with the square root of time.

Q. 4: With respect to potential corrosion from the interior, Dr. Hausler has testified that "[c]onsiderably higher short term [interior] corrosion rates have probably occurred. In the absence of any good information on this issue, I believe it would be prudent to allow for an interior corrosion rate that is a multiple of 0.002 inches per year, if new water is introduced into the interior floor by repairs to control rod drives, use of the containment spray, or other sources." (Rebuttal Testimony, A.19). Is this realistic?

A. 4: (BMG) No, for the reasons provided in Part 6 of AmerGen's Rebuttal Testimony, A.9 and A.10. "Any corrosion [in the interior embedded drywell surface] would be vanishingly small and of no engineering concern." This is due to the high pH of any water in contact with the interior surface of the embedded drywell shell, the lack of measurable corrosion on the newly-exposed shell surface during the 2006 refueling outage, and the inerted air environment inside the drywell during operations.

Any new water introduced on to the concrete floor by "repairs to control rod drives, the use of containment spray, or other sources" will have its pH subsequently increased due to the high solubility of calcium hydroxide, $Ca(OH)_2$, *i.e.*, the most soluble cement paste compound, from the concrete. This phenomenon is document in L.

Bertolini, et al., *Corrosion of Steel in Concrete – Prevention, Diagnosis, Repair*, Wiley-VCH, Weinheim, Germany, 2004, page 57. Relevant excerpts are attached as Applicant's Exhibit 60.

Q. 5: Apparently based on the interior corrosion rate of 0.002" per year postulated in Dr. Hausler's Testimony, A.19, Citizens' argue that, "[i]n the absence of any good information on this issue, it is prudent to allow for a corrosion rate of up to 10 mils per year after new water is introduced onto the interior floor by repairs to control rod drives, the use of containment spray, or other sources." (Citizens' Rebuttal Statement, page 23) Do you agree with this statement?

A. 5: (BMG) There is absolutely no justification for multiplying this assumed general corrosion rate of 0.002" per year by a factor of five to derive an even a more dubious general corrosion rate of 0.010" per year. It is important to note that normal corrosion engineering practice is to conservatively double the general corrosion rate to provide extra margin, not to multiply the general corrosion rate by a factor of five.

The general corrosion rate of carbon steel embedded in clean concrete, *i.e.*, no chlorides or carbon dioxide, is negligible (<0. 000008" per year). This value is based on L. Bertolini, *et al.*, *Corrosion of Steel in Concrete – Prevention, Diagnosis, Repair*, Wiley-VCH, Weinheim, Germany, 2004, page 74. (Applicant's Exh. 60). Even in the presence of aggressive substances such as chlorides or carbon dioxide, which degrade the passive film formed on the carbon steel surface, at a high relative humidity (RH) of 80% and 90%, respectively, the general corrosion rate of steel is approximately only 0.0006" per year, as described in Applicant's Exhibit 60, page 74.

Thus, Citizens' postulated internal surface proposed corrosion rate is unreasonable and the added margin multiplier factor lacks any engineering basis.

Q. 6: Citizens state that the total (annual) corrosion rate could be 0.050" per year (Citizens' Rebuttal Statement, page 11). This is based on their estimate that "[f]uture corrosion rates after refueling outages are up to 0.01 inches per year from the interior and 0.39 inches per year from the exterior. The total corrosion rate could therefore be approximately 0.05 inches per year." Is this a reasonable estimate of the potential corrosion rate?

A. 6: (BMG) No. The highest historical general corrosion rate ever measured in the OCNGS sand bed region of 0.039" per year took place in a corrosion system consisting of water-saturated sand in direct contact with an uncoated carbon steel drywell. That corrosion system no longer exists, so the corrosion rate value is no longer valid. The corrosion system has changed as follows:

- The water-retaining and ion-containing sand has been removed
- The ingress of additional water has been mitigated
- The carbon steel drywell has been coated

Nevertheless, as I described in my Rebuttal testimony, A.15, even "if I assumed that the highest levels of corrosion ever experienced in the sand bed region could recur, the total potential corrosion rate," when accounting for the time of wetness ("$T_W$"), is only 0.007" over two years.

Citizens' estimate of the interior corrosion rate of 0.010" per year is unjustified, for the reasons described in A.5, above. Citizens also add 0.001" per year, for no apparent reason. Thus, there is no basis for a total corrosion rate of 0.50" per year.

Q. 7: Dr. Hausler cites the "Handbook of Chemistry and Physics" to counter AmerGen's position that "corrosion product occupies from 7 to 10 times the volume of the iron from which it originates." (Citizens' Exh. 39, page 18). Please respond to Dr. Hausler's statement.

A. 7: (BMG) In the information cited by Dr. Hausler from the "Handbook of Chemistry and Physics," the relative densities of iron and its common corrosion products are based on theoretical values of pure oxides. In reality, oxides are not pure and usually occupy much larger volumes due to defects in the oxide/hydrate structure such as vacancies and voids.

## III. AIR FLOW IN THE SAND BED REGION

Q. 8: Is Dr. Hausler correct when he says that "the exterior of the sandbed region . . . has very limited air exchange"? (Citizens' Rebuttal Testimony, A22).

A. 8: (EWH) No. While the exterior of the sand bed region is not served by forced ventilation, air exchange will occur in the sand bed region in response to temperature changes in the drywell shell and the surrounding air. As explained in AmerGen's SurRebuttal Testimony, Part 1, A.3, Applicant's Exhibits 4 and 7 show that the drywell vents penetrate the concrete at the top of the sand bed region. The gaps between the vent headers and the concrete provide substantial area for air flow, as do many piping penetrations from the drywell. All of these openings combined with the air gap between the drywell liner and the concrete shield walls create a "chimney" which will tend to promote airflow in this area. In particular, as the drywell liner heats up following an outage, the resulting temperature differential between the drywell shell and the surrounding air will induce natural circulation air flow in the sand bed region.

Q. 9: Citizens have alleged that AmerGen's testimony uses the incorrect equation to determine the evaporation rate of water from the drywell shell surface following an outage.

Specifically, Dr. Hausler states that because the air in the sand bed region is "totally stagnant," the equation used "describes a steady state, while the rate of evaporation in the confined space of the sand bed area would have to be described by a transient equation." (Citizens' Exh. 39, page 19). Is Dr. Hausler correct?

A. 9: (EWH) No. As I stated in my response above (A.8), the air in the sand bed region is not stagnant. Since air can, and does, flow through this area, the evaporation in this region would not have to be described by a transient equation.

Q. 10: In your direct testimony (A.19), how did you account for the potential low velocity of air across the shell surface?

A. 10: (EWH) I conservatively accounted for the low velocity of air across the shell by setting the wind velocity equal to zero. At this point, the evaporation is strictly governed by differences in saturation pressure between the water film assumed on the drywell exterior, and the air in the sand bed region.

Q. 11: Please explain why it is acceptable to use a velocity of zero in this equation, rather than using a different equation altogether.

A. 11: (EWH) Because air is free to be exchanged in the sand bed region, but the velocity is not known, setting the value equal to zero conservatively limits evaporation to differences in saturation pressure, which are temperature-driven. Because air is free to flow through the area, the air will not saturate and steady state equations will adequately describe evaporation in this area.

Q. 12: Do you agree with Dr. Hausler that, "[i]t is therefore likely that in the event of water leakage into the region, the air in the sandbed region would become fully saturated during the outage (transient phenomenon). It would then have very limited capacity to absorb moisture as the temperature increased with plant start up."? (Citizens' Rebuttal Testimony, A22).

A. 12: (EWH) No. Once again, because air is free to circulate through this region, the air in the sandbed region will not become fully saturated, so Dr. Hausler is wrong.

Q. 13: Do you agree with Dr. Hausler that "[t]he ability of new air to reach the sand pocket has been reduced by the placement of tubes leading to polystyrene bottles in the sand bed drains. Thus, it is likely that any moisture on the exterior of the shell would evaporate slowly."? (Citizens' Rebuttal Testimony, A22).

A. 13: (EWH) No. As I stated in A.8, above, significant air flow area exists in the sand bed region, even with the drainage tubes installed in the sand bed drains.

## IV. DR. HAUSLER'S EXPERTISE

Q. 14: Mr. Gordon, are you aware of any new information about Dr. Hausler's expertise with regard to the potential corrosion rate in the OCNGS sand bed region?

A. 14: (BMG) Yes. Citizens submitted additional information about Dr. Hausler's qualifications and the papers he has authored in their response to Amergen's Motion in Limine of July 27. Dr. Hausler identified some articles that are attached as Applicant's Exhibits 57, 58, and 59. I was not able to retrieve these documents in time to incorporate any comments on them into AmerGen's Rebuttal Testimony. I have now reviewed these papers and the topics discussed in them confirm that Dr. Hausler's expertise is primarily in oil field applications that have very little in common with the OCNGS sand bed region.

Q. 15: Do you have anything else to add?

A. 15: (BMG) Yes. In my Rebuttal Testimony, A.10, I compared the chemistry sample results of water from the drywell shell interior to the guidelines in NRC Generic Aging Lessons

Learned (GALL) Report (Vol. 2, Rev. 1, at II A.1 through 5). Relevant portions of the GALL Report are attached as Applicant's Exhibit 61.

Q. 16: Does this conclude your testimony?

A. 16: (All) Yes.

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

| | |
|---|---|
| Barry Gordon | Date 9/12/07 |
| Edwin Hosterman | Date |

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

| | |
|---|---|
| Barry Gordon | Date |
| Edwin Hosterman | 9-12-07<br>Date |

DOCKETED
USNRC

September 17, 2007 (7:45am)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

**UNITED STATES OF AMERICA**
**NUCLEAR REGULATORY COMMISSION**

**ATOMIC SAFETY AND LICENSING BOARD**

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

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| In the Matter of: | September 14, 2007 |
| AmerGen Energy Company, LLC | |
| (License Renewal for Oyster Creek Nuclear Generating Station) | Docket No. 50-219 |

**AMERGEN'S PRE-FILED SURREBUTTAL TESTIMONY EXHIBITS**

**EXHIBITS 37-61**

APPLICANT'S EXHIBIT 37

April 24, 1992

Docket No. 50-219

Distribution:
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Mr. John J. Barton
Vice President and Director
GPU Nuclear Corporation
Oyster Creek Nuclear Generating Station
Post Office Box 388
Forked River, New Jersey 08731

Dear Mr. Barton:

SUBJECT: EVALUATION REPORT ON STRUCTURAL INTEGRITY OF THE OYSTER CREEK DRYWELL (TAC NO. M79166)

The staff has completed the review and evaluation of the stress analyses and stability analyses reports of the corroded drywell with and without the sand bed. Our evaluation report is contained in the enclosure. GPUN used the analyses to justify the removal of the sand from the sand bed region. Even though the staff, with the assistance of consultants from Brookhaven National Laboratory (BNL), concurred with GPUN's conclusion that the drywell meets the ASME Section III Subsection NE requirements, it is essential that GPUN continue UT thickness measurements at refueling outages and at outages of opportunity for the life of the plant. The measurements should cover not only areas previously inspected but also accessible areas which have never been inspected so as to confirm that the thickness of the corroded areas are as projected and the corroded areas are localized.

We request that you respond within 30 days of receipt of this letter indicating your intent to comply with the above requirements as discussed in the Safety Evaluation.

The requirements of this letter affect fewer than 10 respondents, and therefore, are not subject to Office of Management and Budget review under P.L. 96-511.

Sincerely,

/s/

Alexander W. Dromerick, Sr. Project Manager
Project Directorate I-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation



Enclosure:
As stated

cc w/enclosure:
See next page



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| NAME | :SNorris | :ADromerick:cn | :JStolz | : | : | : |
| DATE | :4/24/92 | :4/24/92 | :4/24/92 | : | : | : |

Mr. John J. Barton
GPU Nuclear Corporation

Oyster Creek Nuclear
Generating Station

cc:

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

DRYWELL STRUCTURAL INTEGRITY

OYSTER CREEK NUCLEAR GENERATING STATION

GPU NUCLEAR CORPORATION

DOCKET NO. 50-219

## I. INTRODUCTION

In 1986 the steel drywell at Oyster Creek Nuclear Generating Station (OCNGS) was found to be extensively corroded in the area of the shell which is in contact with the sand cushion around the bottom of the drywell. Since then GPU Nuclear Corporation, (GPUN, the licensee of OCNGS), has instituted a program of periodic inspection of the drywell shell sand cushion area through ultrasonic testing (UT) thickness measurements. The inspection has been extended to other areas of the drywell and some areas above the sand cushion have been found to be corroded also. From the UT thickness measurements, one can conclude that corrosion of the drywell shell in the sand cushion area is continuing. In an attempt to eliminate corrosion or reduce the corrosion rate, the licensee tried cathodic protection and found it to be of no avail. An examination of the results of consecutive UT measurements, confirmed that the corrosion is continuing. There is concern that the structural integrity of the drywell cannot be assured. Since the root cause of the corrosion in the sand cushion area is the presence of water in the sand, the licensee has considered sand removal to be an important element in its program to eliminate the corrosion threat to the drywell integrity.

In the program, the licensee first established the analysis criteria and then performed the analyses of the drywell for its structural adequacy with and without the presence of the sand. The licensee performed stress analyses and stability analyses for both with and without the sand cases and concluded the drywell with or without the sand to be in compliance with the criteria established for the reevaluation. It is to be noted that the original purpose of the sand cushion is to provide a smooth transition of stresses from the fixed portion to the free-standing portion of the steel drywell.

## II. EVALUATION

The staff with the assistance of consultants from Brookhaven National Laboratory (BNL) has reviewed and evaluated the information (Refs. 1,2,3,4,5) provided by the licensee.

1. <u>Re-Analysis Criteria</u>

The drywell was originally designed and constructed to the requirements of ASME Section VIII code and applicable code cases, with a contract date of July 1, 1964. The Section VIII Code requirements for nuclear containment vessels at that time were less detailed than at any subsequent date. The evolution of the ASME Section III Code for metal containments and its relation with ASME Section VIII Code were reviewed and evaluated by Teledyne Engineering Services (TES). The evaluation criteria used are based on ASME Section III Subsection NE Code through the 1977 summer addenda. The reason for the use of the Code of this vintage is that it was used in the Mark I containment program to evaluate the steel torus for hydrodynamic loads and that the current ASME Section III Subsection NE Code is closely related to that version. The following are TES's findings relevant to Oyster Creek application:

a) The steel material for the drywell is A-212, grade B, Firebox Quality (Section VIII), but it is redesignated as SA-516 grade in Section III.

b) The relation between the allowable stress (S) in Section VIII and the stress intensity (Smc) in Section III for metal containment is 1.1S = Smc.

c) Categorization of stresses into general primary membrane, general bending and local primary membrane stresses and membrane plus bending stresses is adopted as in Subsection NE.

d) The effect of a locally stressed region on the containment shell is considered in accordance with NE-3213.10.

In addition to ASME Section III Subsection NE Code, the licensee has also invoked ASME Section XI IWE Code to demonstrate the adequacy of the Oyster Creek drywell. IWE-3519.3 and IWE-3122.4 state that it is acceptable if either the thickness of the base metal is reduced by no more than 10% of the normal plate thickness or the reduced thickness can be shown by analysis to satisfy the requirements of the design specification.

The staff has reviewed the licensee's adoption of ASME Section III Subsection NE and Section XI Subsection IWE in its evaluation of the structural adequacy of the corroded Oyster Creek drywell, and has found it to be generally reasonable and acceptable.

By adopting the Subsection NE criteria, the licensee has treated the corroded areas as discontinuities per NE-3213.10, which was originally meant for change in thicknesses, supports, and penetrations. These discontinuities are highly localized and should be designed so that their presence will have no effect on the overall behavior of the containment shell. NE-3213.10 defines clearly the level of stress intensity and the extent of the discontinuity to be considered localized. A stress intensity limit of 1.1 Smc is specified at the boundary of the region within which the membrane stress can be higher than 1.1 Smc. The region where the stress intensity varies from 1.1 Smc to 1.0 Smc is not defined in the Code because of the fact that it varies with the loading. In view of this, the licensee rationalized that the 1.1 Smc can be applied beyond the region defined by NE-3213.10 for localized discontinuity without any restriction throughout the drywell. The staff disagreed with the licensee's interpretation of the Code. The staff pointed out that for Oyster Creek drywell, stresses due to internal pressure should be used as the criterion to establish such a region. The interpretation of Section XI Subsections IWE-3519.3 and IWE-3122.4 can be made only in the same context. It is staff's position that the primary membrane stress limit of 1.1 Smc not be used indiscriminately throughout the drywell.

In order to use NE-3213.10 to consider the corroded area as a localized discontinuity, the extent of the reduction in thickness due to corrosion should be reasonably known. UT thickness measurements are highly localized; however, from the numerous measurements so far made on the Oyster Creek drywell, one can have a general idea of the overall corroded condition of the drywell shell and it is possible to judiciously apply the established re-analysis criteria.

2. Re-analyses

The re-analyses were made by General Electric Company for the licensee, one reanalysis considered the sand present and the other considered the drywell without the sand. Each re-analysis comprises a stress analysis and stability analysis. Two finite element models, one axisymmetric and another a 36° pie slice model were used for the stress analysis. The ANSYS computer program was used to perform the analyses. The axisymmetric model was used to determine the stresses for the seismic and the thermal gradient loads. The pie slice model was used for dead weight and pressure loads. The pie slice model includes the vent pipe and the reinforcing ring, and was also used for buckling analysis. The same models were used for the cases with and without sand, except that in the former, the stiffness of sand in contact with the steel shell was considered. The shell thickness in the sand region was assumed to be 0.700" for the with-sand case and to be 0.736" for the without-sand case. The 0.70" was, as claimed by the licensee, used for conservatism and the 0.736" is the projected thickness at the start of fuel cycle 14R. The same thicknesses of the shell above the sand region were used for both cases. For the with-sand case, an analysis of the drywell with the original nominal wall thicknesses was made to check the shell stresses with the allowable values established for the re-analyses.

The licensee used the same load combinations as specified in Oyster Creek's final design safety analysis report (FDSAR) for the re-analyses. The licensee made a comparison of the load combinations and corresponding allowable stress limits using the Standard Review Plan (SRP) section 3.8.2 and concluded they are comparable.

The results of the re-analyses indicated that the governing thicknesses are in the upper sphere and the cylinder where the calculated primary membrane stresses are respectively 20,360 psi and 19,850 psi vs. the allowable stress value of 19,300 psi. There is basically no difference, in the calculated stresses at these levels, between the with and without sand cases. This should be expected, because in a steel shell structure the local effect or the edge effect is damped in a very short distance. The stresses calculated exceed the allowable by 3% to 6%, and such exceedance is actually limited to the corroded area as obtained from UT measurements. However, in order to perform the axisymmetric analysis and analysis of the pie slice model, uniform thicknesses were assumed for each section of the drywell. Therefore, the calculated over-stresses may represent only stresses at the corroded areas and the stresses for areas beyond the corroded areas are less and would most likely be within the allowable as indicated in results of the analyses for nominal thicknesses. The diagram in Ref. 6 indicated such a condition. It is to be noted that the stresses for the corroded areas were obtained by multiplying the stresses for nominal thicknesses by the ratios between the corroded and nominal thicknesses.

The buckling analyses of the drywell were performed in accordance with ASME Code Case N-284. The analyses were done on the 36° pie slice model for both with-sand and without-sand cases. Except in the sand cushion area where a shell thickness of 0.7" for the with-sand case and a shell thickness of 0.736" for the without-sand case were used, nominal shell thicknesses were considered for other sections. The load combinations which are critical to buckling were identified as those involving refueling and post accident conditions. By applying a factor of safety of 2 and 1.67 for the load combinations involving refueling and the post-accident conditions respectively, the licensee established for both cases the allowable buckling stresses which are obtained after being modified by capacity and plasticity reduction factors. It is found that the without-sand, case for the post-accident condition is most limiting in terms of buckling with a margin of 14%. The staff and its Brookhaven National Laboratory (BNL) consultants concur with the licensee's conclusion that the Oyster Creek drywell has adequate margin against buckling with no sand support for an assumed sandbed region shell thickness of 0.736 inch.

A copy of BNL's technical evaluation report is attached to this safety evaluation.

## III. CONCLUSION

With the assistance of consultants from BNL, the staff has reviewed and evaluated the responses to the staff's concerns and the detailed re-analyses of the drywell for the with-sand and without-sand cases. The reanalyses by the licensee indicated that the corroded drywell meets the requirements for containment vessels as contained in ASME Section III Subsection NE through summer 1977 addenda. This Code was adopted in the Mark I containment program. The staff agrees with the licensee's justification of using the above mentioned Code requirements with one exception, the use of 1.1 Smc throughout the drywell shell in the criteria for stress analyses. It is the staff's position that the primary membrane stress limit of 1.1 Smc not be used indiscriminately throughout the drywell. The staff accepted the licensee's reanalyses on the assumption that the corroded areas are highly localized as indicated by the licensee's UT measurements. The stresses obtained for the case of reduced thickness can only be interpreted to represent those in the corroded areas and their adjacent regions of the drywell shell. In view of these observations, it is essential that the licensee perform UT thickness measurements at refueling outages and at outages of opportunity for the life of the plant. The measurements should cover not only areas previously inspected but also accessible areas which have never been inspected so as to confirm that the thicknesses of the corroded areas are as projected and the corroded areas are localized. Both of these assumptions are the bases of the reanalyses and the staff acceptance of the reanalysis results.

References:


1. "An ASME Section VIII Evaluation of the Oyster Creek Drywell Part 1, Stress Analysis" GE Report No. 9-1 DRF #00664 November 1990, prepared for GPUN (with sand).

2. "Justification for use of Section III, Subsection NE, Guidance in Evaluating the Oyster Creek Drywell" TR-7377-1, Teledyne Engineering Services, November 1990 (Appendix A to Reference 1).

3. "An ASME Section VIII evaluation of the Oyster Creek Drywell, Part 2, Stability Analysis" GE Report No. 9-2 DRF #00664, Rev. 0, & Rev. 1. November 1990, prepared for GPUN (with sand).

4. "An ASME Section VIII Evaluation of Oyster Creek Drywell for without sand case, Part I, stress analysis" GE Report No. 9-3 DRF #00664, Rev. 0, February 1991. Prepared for GPUN.

5. "An ASME Section VIII Evaluation of Oyster Creek Drywell, for without sand case, Part 2 Stability Analysis" GE Report No. 9-4, DRF #00664 Rev. 0, Rev. 1 November 1990, prepared for GPUN.

6. Diagram attached to a letter from J. C. Devine Jr. of GPUN to NRC dated January 17, 1992 (C321-92-2020, 5000-92-2094).


Principal Contributor: C.P. Tan

Date: April 24, 1992

Attachment:
BNL Technical Evaluation
Report

ATTACHMENT

# BROOKHAVEN NATIONAL LABORATORY
# TECHNICAL EVALUATION REPORT
# ON
# STRUCTURAL ANALYSES OF THE CORRODED OYSTER CREEK STEEL DRYWELL

## 1. Introduction

An inspection of the steel drywell at the Oyster Creek Nuclear Generating Station in November 1986 revealed that some degradation due to corrosion had occurred in the sandbed region of the shell. Subsequent inspections also identified thickness degradations in the upper spherical and cylindrical sections of the drywell. The licensee, GPU Nuclear Corporation, has performed structural analyses to demonstrate the integrity of the drywell for projected corroded conditions that may exist at the start of the fourteenth refueling outage (14R). This outage is expected to start in October 1992. In an attempt to arrest the corrosion, the licensee plans to remove the sand from the sandbed region. Consequently, they have submitted structural analyses of the drywell both with and without sand for drywell wall thicknesses projected to exist at the start of 14R outage.

## 2. Summary of Licensee's Analyses

The analyses performed by the licensee utilized the drywell wall thicknesses summarized in Table 1.

Table 1
Drywell Wall Thicknesses

| Drywell Region | As-Designed Thicknesses (in.) | Projected 95% Confidence 14R Thicknesses (in.) |
|---|---|---|
| Cylindrical Region | 0.640 | 0.619 |
| Knuckle | 2.5625* | 2.5625* |
| Upper Spherical Region | 0.722 | 0.677 |
| Middle Spherical Region | 0.770 | 0.723 |
| Lower Spherical Region Except Sand Bed Area | 1.154 | 1.154 |
| Sand Bed Region | 1.154 | 0.736 |

*NOTE: Table 2-1 of both References 1 and 3 indicates that the knuckle thickness is 2.625". This appears to be a mistake since the knuckle thickness is shown to be 2-9/16" in Figure 1-1 of the same report.

The stress analysis for the "with sand" case is described in Reference 1. For this analysis the licensee utilized the as-designed thicknesses, except for the sandbed region where a thickness of 0.70" was used. The stress results were obtained from a finite element analysis which utilized axisymmetric solid elements and the ANSYS computer program. Later, the stress results were scaled to address the local thinning in areas other than the sandbed region (the projected 95% confidence 14R thicknesses in Table 1). The loads and load combinations considered in the analysis are based on the FSAR Primary Containment Design Report and the 1964 Technical Specification for the Containment. Appendix E of Reference 1 compares the load combinations considered in the analysis with those given in Section 3.8.2 of the NRC Standard Review Plan, Rev. 1, July 1981.

The stress analysis for the "without sand" case is described in Reference 3. For this analysis the licensee also utilized the as-designed thicknesses, except for the sandbed region where a thickness of 0.736" was used. In this case, two finite element models, an axisymmetric and a 36° pie slice model, were used. The axisymmetric model is essentially the same as that used in Reference 1; however, the elements representing the sand stiffness were removed. This model was used to determine the seismic and thermal stresses. The pie slice model was used to determine the dead weight and pressure stresses, as well as the stresses for load combinations. The pie slice model included the effects of the vent pipes and the reinforcing ring in the drywell shell in the vicinity of each vent pipe. The drywell and vent shell were modeled using 3-dimensional elastic-plastic quadrilateral shell elements. At a distance of 76 inches from the drywell shell, beam elements were used to model the remainder of the ventline. The loads and load combinations are the same as those considered in Reference 1.

The code of record for the Oyster Creek drywell is the 1962 Edition of the ASME Code, Section VIII with Addenda to Winter 1963, and Code Cases 1270N-5, 1271N and 1272N-5. The licensee utilized these criteria in evaluating the stresses in the drywell, but also utilized guidance from the NRC Standard Review Plan with regard to allowable stresses for service level C and the post-accident condition. The licensee also used guidance from Subsection NE of Section III of the ASME Code in order to justify the use of a limit of $1.1S_{mc}$ in evaluating the general membrane stresses in areas of the drywell where reduced thicknesses are specified. Based on these criteria the licensee has concluded that the stresses in the drywell shell are within code allowable limits for both the "with sand" and "without sand" cases.

The licensee also performed stability analyses of the drywell for both the "with sand" case (Reference 2) and the "without sand" case (Reference 4). For the "with sand" case the licensee utilized the as-designed thicknesses shown in Table 1, except in the sandbed region where a thickness of 0.700 inch was used. For the "without sand" case the same thicknesses were used , except in the sandbed region where a thickness of 0.736 inch was used. The buckling capability of the drywell for both the "with sand" and "without sand" cases was evaluated by using the 36° pie slice finite element model discussed above. For the "with sand" case spring elements were used in the sandbed region to model the sand support. For the "without sand" case these spring elements were removed. The most limiting load combinations which result in the highest compressive stresses in the sandbed region were considered for the buckling analysis. These are the refueling condition (Dead Weight + Live Load + Refueling Water Weight + External Pressure + Seismic) and the post-accident condition (Dead Weight + Live Load + Hydrostatic Pressure for Flooded Drywell + External Pressure + Seismic).

The buckling evaluations performed by the licensee follow the methodology described in ASME Code Case N-284, "Metal Containment Shell Buckling Design Methods, Section III, Class MC", Approved August 25, 1980. The theoretical elastic buckling stress is calculated by analyzing the three dimensional finite element model discussed above. Then the theoretical buckling stress is modified by capacity and plasticity reduction factors. The allowable compressive stress is obtained by dividing the calculated buckling stress by a factor of safety. In accordance with Code Case N-284 the licensee used a factor of safety of 2.0 for the refueling condition and 1.67 for the post-accident condition. The capacity reduction factors were also modified to take into account the effects of hoop stress. Originally the licensee based the hoop stress modification on data related to the axial compressive strength of cylinders (References 2 and 4). Later the licensee revised the approach based on a review of spherical shell buckling data and recalculated the drywell buckling capacities for both the "with sand" and "without sand" cases (Reference 8). For the "with sand" case, the licensee reports a margin above the allowable compressive stress of 47% for the refueling condition and 40% for the post-accident condition. For the "without sand" case, the licensee reports margins of 24.5% for the refueling condition and 14% for the post-accident condition.

3. <u>Evaluation of Licensee's Approach</u>

The analyses performed by the licensee as summarized in Section 2 and discussed more fully in References 1 through 4 have been reviewed and found to provide an acceptable approach for demonstrating the structural integrity of the corroded Oyster Creek drywell. The finite element analyses performed for both the stress and stability evaluations are consistent with industry practice. Except for the use of a limit of $1.1S_{mc}$ in evaluating the general membrane stress in areas of reduced drywell thickness, the loads, load combinations and acceptance criteria used by the licensee are consistent with the guidance given in Section 3.8.2 of the NRC Standard Review Plan, Rev. 1, July 1981. To further support their position, the licensee has provided two appendices to Reference 1.

Appendix A provides a detailed justification for the use of Section III, Subsection NE as guidance in evaluating the Oyster Creek drywell. Appendix E compares the load combinations given in the Final Design Safety Analysis Report (FDSAR) with the load combinations given in SRP 3.8.2 and demonstrates that the load combinations used in the analysis envelop those given in the SRP.

In the areas of the drywell where reduced thicknesses are specified, the licensee has used a limit of $1.1S_{mc}$ to evaluate the general membrane stresses. In support of this position the licensee has cited the provisions of NE-3213.1 of the ASME Code concerning local primary membrane stresses. In effect, the licensee's criteria would treat corroded or degraded areas as discontinuities. For such considerations the code places no limit on the extent of the region in which the membrane stress exceeds $1.0S_{mc}$ but is less than $1.1S_{mc}$. In support of this position the licensee has provided the opinion of Dr. W.E. Cooper, a well known expert on the development of the ASME Code. Dr. Cooper concluded that "given a design which satisfies the general Code intent, as the Oyster Creek drywell does as originally constructed, it is not a violation of Subsection NE requirements for the membrane stress to be between $1.0S_{mc}$ and $1.1S_{mc}$ over significant distances". The licensee has also cited the provisions of IWE-3519.3 which accepts up to a 10% reduction in the thickness of the original base metal.

The licensee's position has merit, but great caution must be exercised to assure that such a position is not applied indiscriminately. In the case of the Oyster Creek drywell the licensee has concluded that "there are very few locations where the calculated stress intensities for design basis conditions, would exceed $1.0S_{mc}$, and in these cases only slightly" (Reference 7). The licensee has provided additional information in Reference 9 to support this conclusion. Based on the information provided by the licensee which demonstrates that the use of the $1.1S_{mc}$ criteria is limited to localized areas, it is concluded that the Oyster Creek drywell meets the intent of the ASME Code.

As discussed in Section 2, the capacity reduction factors used in the buckling analysis are modified to take into account the beneficial effects of tensile hoop stress. As a result of a question raised during the review regarding this matter, the licensee submitted additional information in Reference 5 to support the approach. This information included a report prepared by C.D. Miller entitled "Effects of Internal Pressure on Axial Compression Strength of Cylinders" (CBI Technical Report No. 022891, February 1991). The report presented a design equation which was the lower bound of the test data included in the report. It also demonstrated that the equation used in References 2 and 4 was conservative relative to the proposed design equation. The report presented further arguments that the rules determined for axially compressed cylinders subjected to internal pressure can be applied to spheres. Subsequently the licensee has submitted Reference 8, which indicates that the original approach was not conservative with regard to its application to spherical shapes and recommends a new equation. However, the documentation supporting the use of this equation is not included in Reference 8, but apparently is contained in a referenced report prepared by C.D. Miller entitled "Evaluation of Stability Analysis Methods Used for the Oyster Creek Drywell" (CBI Technical Report Prepared for GPU Nuclear Corporation, September 1991). This report was subsequently submitted and reviewed by the NRC staff. As discussed in Section 2, the use of the revised equation still results in calculated capacities in compliance with the ASME Code provisions; however, the margins beyond those capacities are reduced from those reported by References 2 and 4.

It is noted that the licensee may have "double-counted" the effects of hoop tension, since the theoretical elastic instability stress was calculated from the finite element model using the ANSYS Code. The elastic instability stress calculated by the ANSYS Code may have already taken into account the effects of hoop tensile stress. However, by comparing the theoretical elastic instability stress and the corresponding circumferential stress predicted by the licensee for the refueling and post-accident cases, it appears that the effect of hoop tension in the ANSYS calculations is small and there is sufficient margin in the results to compensate for the potential "double-counting". Furthermore, it is judged that there is sufficient capacity in the drywell to preclude a significant buckling failure under the postulated loading conditions since the licensee's calculations: (a) incorporate factors of safety of 1.67 to 2.0, depending upon the load condition, and (b) utilize a conservative assumption by considering the shell wall thickness to be severely reduced for the full circumference of the drywell throughout the sandbed region.

During the course of the review of the licensee's submittals, a number of other issues were raised regarding the approach. These included: (a) the basis and method of calculating the projected drywell thicknesses, (b) the scaling of the calculated stresses for the nominal thickness case by the thickness ratio, (c) the effect of stress concentrations due to the change of thickness, (d) monitoring of the drywell temperature, (e) sensitivity of stresses due to variations in the sand spring stiffness, (f) sensitivity of the plasticity reduction factor in the buckling analysis, (g) use of the 2 psi design basis external pressure in the buckling analysis, (h) effect of the large displacement method, (i) the treatment of the large concentrated loads considered in the analysis, and (j) the method of applying the seismic loads to the pie slice model. These issues were adequately addressed by the additional information provided by the licensee in References 5 and 6.

## 4. Conclusions

The licensee has demonstrated that the calculated stresses in the Oyster Creek drywell (both with and without the sandbed), as a result of the postulated loading conditions, meet the intent of the ASME Code for projected corroded conditions that may exist at the start of the fourteenth refueling outage. However, if the actual thickness in the sandbed region at 14R is close to the projected thickness of 0.736", there may not be adequate margin left for further corrosion through continued operation unless it is demonstrated that removal of sand will completely stop further thickness reductions. The licensee has also demonstrated that there is sufficient margin in the drywell design (both with and without the sandbed) to preclude a buckling failure under the postulated loading conditions.

It should be recognized that the conclusions reached by the licensee have been accepted for this particular application with due regard to all the assumptions made in the analysis and the available margins. The use of the $1.1S_{mc}$ criteria for evaluating general membrane stress in corroded or degraded areas should be investigated further by the NRC staff and the ASME Code Committee and appropriate bounds established before it is accepted for general use. The licensee's buckling criteria regarding the modification of capacity reduction factors for tensile hoop stress and the determination of plasticity reduction factors should also be investigated in a similar manner.

## 5. References


1. GE Report Index No. 9-1, "An ASME Section VIII Evaluation of the Oyster Creek Drywell - Part 1 - Stress Analysis", November 1990.

2. GE Report Index No. 9-2, "An ASME Section VIII Evaluation of the Oyster Creek Drywell - Part 2 - Stability Analysis," November 1990.

3. GE Report Index No. 9-3, "An ASME Section VIII Evaluation of the Oyster Creek Drywell for Without Sand Case - Part 1 - Stress Analysis," February 1991.

4. GE Report Index No. 9-4, "An ASME Section VIII Evaluation of the Oyster Creek Drywell for Without Sand Case - Part 2 - Stability Analysis," February 1991.

5. GPU Nuclear letter dated March 20, 1991, "Oyster Creek Drywell Containment."

6. GPU Nuclear letter dated June 20, 1991, "Oyster Creek Drywell Containment".

7. GPU Nuclear letter dated October 9, 1991, "Oyster Creek Drywell Containment"

8. GPU Nuclear letter dated January 16, 1992, "Oyster Creek Drywell Containment".

9. GPU Nuclear letter dated January 17, 1992, "Oyster Creek Drywell Containment".

APPLICANT'S EXHIBIT 38

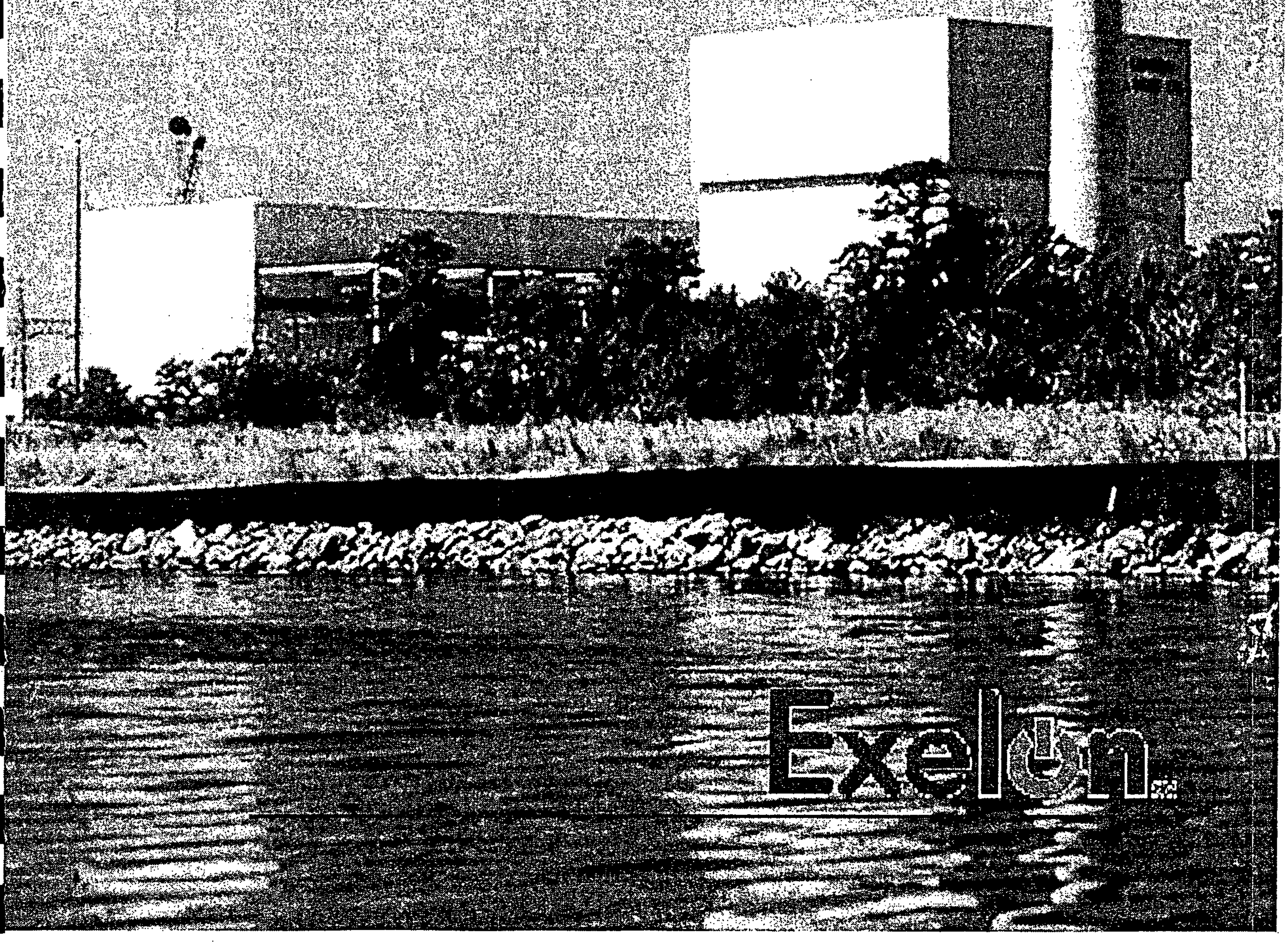
Amer

Oyster Creek Nuclear Generating Station

# Updated
# Final Safety Analysis Report

Revision 13

April 2003



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## 3.8 DESIGN OF CATEGORY I STRUCTURES

The General Electric Company was the prime contractor for Jersey Central Power and Light Co. in the design and construction of the Oyster Creek Nuclear Generating Station (OCNGS). Thus, General Electric had the overall responsibility for the Containment System as a part of the total plant.

General Electric Company engaged the services of Burns & Roe, Inc. for engineering assistance and construction management. General Electric furnished the conceptual information drawings, design criteria, and design specifications. Burns & Roe was responsible for the detailed design, construction drawings, specifications, and management of the actual construction and installation. All Burns & Roe drawing information was supplied to General Electric who had the privilege of review and approval.

Burns & Roe, Inc., subcontracted the design, construction, and testing of the drywell and torus vessel, and vent system work to Chicago Bridge & Iron Company.

Subsequent to the initial design and the start of commercial operation, certain modifications were made to the torus under the Mark I Containment System Evaluation Program. This program is further discussed in Subsection 3.8.2.

Evaluations of the structural soundness of the Drywell were performed during 1986 and 1987. The results of these evaluations showed evidence of Drywell wall thinning at various locations. These evaluations, the results thereof, and mitigative measures, as applicable, are discussed in Section 3.8.2.8.

In addition, under the Systematic Evaluation Program (SEP), and independent review was conducted of the seismic design aspects of the OCNGS as they relate to overall design margins. The report "Seismic Review of the Oyster Creek Nuclear Power Plant as Part of the Systematic Evaluation Program", NUREG/CR-1981, UCRL-53018, RD, RM, was issued to summarize the evaluation program. The SEP is summarized in Section 1.10.

### 3.8.1 Concrete Containment

Not applicable

### 3.8.2 Steel Containment

The Function of the Primary Containment System is to accommodate, with minimum leakage, the pressures and temperatures resulting from the break of any enclosed process pipe, and thereby limit the release of radioactive fission products to values which will insure offsite dose rates well below 10CFR100 guideline limits. The design integrated leak rate for the system is no greater than 0.5 percent of its total volume per day at 35 psig.

The development, design, fabrication and construction of the OCNGS Primary Containment are discussed in detail in Reference 1. For the design and construction of the Primary Containment, Burns & Roe prepared a detailed design specification and bid package from design criteria information supplied by General Electric. Chicago Bridge & Iron assumed responsibility for providing the primary components of the Containment System. All design and construction drawings were submitted to Burns & Roe for approval and to General Electric for review prior to construction. Included in this package were openings and sleeves (nozzles) through the drywell wall to accommodate the penetration of process piping, instrumentation, and electrical lines. The actual penetration line fixtures and seals design, fabrication, and testing was subcontracted by Burns & Roe to piping or electrical fabricators as appropriate.

Subsequent to the design completion and start of commercial operation, additional loading conditions which arise in the functioning of the pressure suppression concept utilized in the Mark I Containment System design were identified. These additional loading conditions resulted in an industry wide reanalysis and modification program which is briefly described in the following paragraphs.

Mark I Containment System Evaluation Program

Background

The original design of the Mark I Containment System considered postulated accident loads previously associated with containment design. These included pressure and temperature loads associated with a Loss-of-Coolant Accident (LOCA), seismic loads, dead loads, jet impingement loads, and hydrostatic loads due to water in the suppression chamber. However, after establishment of the original design criteria, additional loading conditions which arise in the functioning of the pressure suppression concept utilized in the Mark I Containment System design were identified. These additional loads resulted from dynamic effects of drywell air and steam being rapidly forced into the suppression pool (torus) during a postulated LOCA and from suppression pool response to safety relief valve (SRV) operation generally associated with plant transient conditions.

Because these hydrodynamic loads had not been considered in the original design of the Mark I containment, the Nuclear Regulatory Commission (NRC) required that a detailed reevaluation of the Mark I containment system be made. In February and April 1975, the NRC transmitted letters to all utilities owning BWR facilities with the Mark I containment system design, requesting that the owners quantify the hydrodynamic loads and assess the effect of these loads on the containment structure. The February 1975 letters reflected NRC concerns about the dynamic loads from SRV discharges, while the April 1975 letters indicated the need to evaluate the containment response to the newly identified dynamic loads associated with a postulated design basis LOCA.

As a result of these letters from the NRC, and recognizing that the additional evaluation effort would be very similar for all Mark I BWR plants, the affected utilities formed an "ad hoc" Mark I Owners Group, and GE was designated as the Group's lead technical organization. The objectives of the Group were to determine the magnitude and significance of these dynamic loads as quickly as possible and to identify courses of action needed to resolve any outstanding safety concerns. The Mark I Owners Group divided this task into two programs: a Short Term Program (STP) and a Long Term Program (LTP).

Short Term Program

The objectives of the Short Term Program (STP) were to verify that each Mark I Containment System would maintain its integrity and functional capability when subjected to the most probable loads induced by a postulated design basis LOCA, and to verify that the licensed Mark I BWR facilities could continue to operate safely without endangering the health and safety of the public while a methodical, comprehensive Long Term Program (LTP) was being conducted.

The STP structural acceptance criteria used to evaluate the design of the torus and related structures were based on providing adequate margins of safety; i.e., a safety to failure factor of 2, to justify continued operation of the plant before the more detailed results of the LTP were available.

The results of the Short Term Program evaluation of the Oyster Creek torus were submitted to the NRC by Jersey Central Power and Light in 1976. As a part of that program, a drywell to wetwell differential pressure was imposed to reduce LOCA loads and a quencher was installed on the SRV discharge line to reduce SRV discharge transient induced loads. The conclusion of the Short Term Program evaluation was that the Oyster Creek torus met the criteria established for the Short Term Program.

The NRC concluded that a sufficient margin of safety had been demonstrated to assure the functional performance of the containment system and, therefore, any undue risk to the health and safety of the public was precluded. These conclusions were documented in the "Mark I Containment Short Term Program Safety Evaluation Report,"

NUREG-0408, dated December 1977. The NRC granted the operating Mark I facilities an exemption relating to the structural factor of safety requirements of 10CFR50.55(a) for an interim period while the more comprehensive LTP was being conducted.

Long Term Program

The objectives of the Long Term Program (LTP) were to establish conservative design basis loads that are appropriate for the anticipated life of each Mark I BWR facility (40 years), and to restore the originally intended design safety margins for each Mark I Containment System. The plans for the LTP and the progress and results of the program were reviewed with the NRC throughout the performance of the program.

The LTP consisted of:

a. The definition of loads for suppression pool hydrodynamic events

b. The definition of structural assessment techniques

c. The performance of a plant unique analysis (PUA) for each Mark I facility

The generic aspects of the Mark I Owners Group LTP were completed with the submittal of the "Mark I Containment Program Structural Acceptance Criteria, Plant Unique Analysis Application Guide" (PUAAG), NEDO-24583-1. The NRC concluded that load definitions and structural acceptance criteria documented in these two reports were acceptable for use in the plant-unique analysis of each plant. The NRC conclusions and comments were presented in the "Mark I Containment Long Term Program Safety Evaluation Report", NUREG-0661, dated July 1980.

Summary of Results

The analysis of the Oyster Creek torus and vent system has been performed in conformance with the requirements of the Mark I Containment Long Term Program. As a result, a number of structural modifications were designed for installation in the OCNGS Primary Containment as part of the Long Term Program.

The results of the analysis, which assumed that the modifications were completed, show that all components of the torus and vent system meet the criteria of the Mark I Long Term Program. Thus, the functional performance of the OCNGS Containment System will be assured for both Loss-of-Coolant Accidents (LOCA) and Safety Relief Valve (SRV) discharge suppression pool hydrodynamic loading conditions. Specific results of the analysis are given in the report "Plant-Unique Analysis Report, Suppression Chamber and Vent System", MPR-733 dated August 1982.

No evaluation of the Oyster Creek drywell was required in the Mark I Containment Long Term Program, since the maximum drywell pressure specified for Oyster Creek in the Long Term Program (NEDO-24572 Rev 2) is well within the design value specified in the original containment design.

The analysis of the piping systems attached to the Oyster Creek torus and vent system has been completed in conformance with the requirements of the Mark I Containment Long Term Program.

A number of piping and pipe support structural modifications were designed for installation as part of the Long Term Program. The analyses are based on the piping arrangement with all modifications installed. The loads used in the analyses of the piping are based upon the response of the Oyster Creek Containment modified as described in the report "Plant-Unique Analysis Report, Suppression Chamber and Vent System", MPR-733, dated August 1982.

The results of the analyses of piping systems attached to the Oyster Creek torus and vent system show that all piping, pipe hangers and supports, nozzles and related components meet the criteria of the Mark I Containment Long Term Program with the modifications completed. Specific results of the analyses are given in the report "Plant Unique Analysis Report, Torus Attached Piping", MPR-734, dated August 1982. These results were updated in MPR-999, Revision 3, "Addendum to MPR-734." (Reference 41)

An evaluation of the nozzles in the vent system for the Electromatic Relief Valves piping penetrations has been performed. The results, as presented in the report MPR-772, "Plant Unique Analysis Supplemental Report," indicate that all stresses are below ASME Code allowables and therefore, the penetrations meet the requirements of the Mark I Containment Long Term Program.

The Mark I Containment Long Term Program Confirmation Order dated January 19, 1982 required plant modifications needed to comply with the Acceptance Criteria in Appendix A of NUREG-0061, Mark I Containment Long Term Program, dated July 1980. This program is now complete for OCNGS.

**Subsequent to the completion of this Mark I Containment Long Term Program, the high pressure actuation setpoints, specified by the Technical Specifications, were increased by 15 psig (Reference 45). To support this increase, an evaluation of the impact of the increased setpoints on Mark I results was completed (Reference 46). This evaluation utilized an estimation of, not a determination of, the resulting increases in stress levels. The results of this estimation were accepted as sufficient bases for assessing the impact of the setpoint increase on previously determined Mark I long term results.**

3.8.2.1 Description of the Containment

The Primary Containment consists of a pressure suppression system with two large chambers as shown in Figure 3.8-1. The drywell houses the reactor vessel, the reactor coolant recirculating loops, and other components associated with the reactor system. It is a 70 ft diameter spherical steel shell with a 33 ft diameter by 23 ft high cylindrical steel shell extending from the top.

The pressure absorption chamber* is a steel shell in the shape of a torus located below and around the base of the drywell. It has a major diameter of 101 ft, a chamber diameter of 30 ft, and is filled to approximately 12 ft depth with demineralized water. The structure is made up of 20 mitered wedge shaped sections or bays with internal stiffening rings or ring girders at each miter.

The two chambers are interconnected through 10 vent pipes 6 ft 6 in in diameter equally spaced around the circumference of the pressure absorption chamber which feed into a common header inside the pressure absorption chamber. This header also takes the shape of a torus of 101 ft major diameter by 4 ft 7 in minor diameter. There are 120 downcomer pipes, 2 ft in diameter, uniformly spaced which have their open ends extending 3 ft below the minimum water level in the pressure absorption chamber. Gas phase return lines with vacuum breaker valves feed back gas to the drywell in case its pressure is less than the absorption chamber.

The base of the drywell is supported on a concrete pedestal conforming to the curvature of the vessel. For erection purposes a structural steel skirt was first provided supporting the vessel. A portion of the steel skirt was left in place to serve as one of the shear rings intended to prevent rotation of the drywell during an earthquake.

After erection, concrete was poured up to the level of the vessel floor providing uniformity in the support by following the contour of the drywell vessel.

A three inch clearance has been provided between the steel vessel of the drywell and the concrete drywell shield wall to provide for a regulated expansion of the drywell steel shell. This clearance was achieved by applying a compressible material to the outside of the drywell vessel prior to placement of the shield wall concrete. For further detail refer to Subsection 3.8.2.4.

The vent header is supported by pinned columns inside the absorption chamber. The downcomers are connected in pairs by pinned braces.

* The pressure absorption chamber is identified often in various reference documents, drawings, and figures as suppression chamber, wetwell, or torus.

Projecting downward from the vent pipe header are downcomer pipes, terminating below the water surface of the pool. During a Loss-of-Coolant Accident (LOCA), the upward reaction from the downcomers is resisted by columns to the bottom of the absorption chamber. Due to the vent clearing jet forces the columns are pinned top and bottom to accommodate the differential horizontal movement between the header and the pressure absorption chamber. The horizontal reaction from the downcomers is resisted by the pinned braces.

Jet deflectors are provided in the drywell at the entrance of each vent pipe to prevent possible damage to them from jet forces which might accompany a pipe break in the drywell.

Access to the pressure absorption chamber from the Reactor Building is provided through two manholes with double gasketed bolted covers which can be tested for leakage.

Access to the drywell is provided through the equipment hatch and personnel air lock and through the double gasketed drywell head cover, all of which have provisions for being individually leak tested.

The pressure absorption chamber is supported on columns located on the outer and inner radii of the torus at the miters. At the center of each bay, a sliding saddle is provided to support the torus, resist upward forces caused by a LOCA, and allow for thermal expansion of the chamber.

The outer columns were pinned at the bottom and the inner columns are pinned at the top and bottom to allow radial growth of the absorption chamber due to temperature and pressure changes. Support for horizontal forces and lateral stability is provided by cross bracing between the outer support columns.

Additional details on the Containment System penetrations and on the equipment hatch and personnel air lock are presented in Subsection 3.8.2.4. The Appendices to Reference 1 provide details and dimensions of these penetrations and the personnel air lock. General arrangement drawings showing the relationship of the Containment System to the surrounding structures are presented as Drawings 3E-153-02-001 through 009. Overall dimensions and volumes of the Containment System are given in Table 3.8-1.

3.8.2.2 Applicable Codes, Standards and Specifications

The design, materials, fabrication, construction and inspection of the Containment System conform to, but are not necessarily limited to, the applicable sections of the following codes and specifications which are used to establish or implement design bases and methods, analytical techniques, material properties, construction techniques and quality control provisions.

Other tests and standards identified by the lead documents listed and in effect or promulgated at the time the design or construction was performed, shall also be considered as viable controlling documents.

The design and construction of the Containment System involved two basic stages:

- Original Construction (Basic Design)

- Subsequent Design Modification

Codes, standards and specifications are presented in the following paragraphs relative to these two stages.

Original Construction (Basic Design)

a. American Society of Mechanical Engineers
Boiler and Pressure Vessel Code, Sections VIII and IX, latest edition at the time of design, with all applicable addenda; nuclear case interpretation 1270 N-5, 1271 N, 1272 N-5 and other applicable case interpretations.

Boiler and Pressure Vessel Code, Section II, latest edition at the time of design with all applicable addenda, for the following material specifications:

| | |
|---|---|
| SA-201 | Carbon-Silicon Steel Plates of Intermediate Tensile Ranges for Fusion-Welded Boilers and Other Pressure Vessels |
| SA-212 | High Tensile Strength Carbon-Silicon Steel Plates for Boilers and Other Pressure Vessels |
| SA-300 | Steel Plates for Pressure Vessels for Service at Low Temperature |
| SA-333 | Seamless and Welded Steel Pipe for Low Temperature Service |
| SA-350 | Forged or Rolled Carbon and Alloy Steel Flanges, Forged Fittings, and Valves and Parts for Low Temperature Service |

b. American Society for Testing and Materials Standards

| | |
|---|---|
| A36 | Structural Steel |
| A193 | Specification for Alloy Steel and Stainless Steel Bolting Material for High Temperature Service |
| A307 | Specification for Low Carbon Steel Externally and Internally Threaded Standard Fasteners |

c. American Institute of Steel Construction

Specification for the design, fabrication and erection of structural steel for buildings.

d. Federal Specifications

| | |
|---|---|
| TT-P-86c | Paint; Red-Lead Base, Ready Mixed |

e. Steel Structures Painting Council Specifications

| | |
|---|---|
| SSPC-SP-3 | Power Tool Cleaning |
| SSPC-SP-6 | Commercial Blast Cleaning |

f. State of New Jersey Laws, Rules and Regulations

g. Burns & Roe Specifications

| | |
|---|---|
| S-2299-4 | Design, Furnishing, Erection and Testing of the Reactor Drywell and Suppression Chamber Containment Vessels |

Design Modification

Modifications subsequent to the basic Containment System design and construction have transpired over a number of years after being initiated in 1975. As such, numerous codes and code revisions have been utilized in carrying out the design and construction efforts.

The following codes, standards and specifications have been supplied to indicate the basic nature of the documents being employed. Specific information relative to actual governing documents used, must be obtained from the individual modification's "System Design Description" for the Oyster Creek plant.

a. American Society of Mechanical Engineers

ASME Boiler and Pressure Vessel Code, Section III, Subsection NE," Class MC Components," (1977 Edition through Summer 1977 Addenda).

ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," Division 1, (1977 Edition through Summer 1978 Addenda).

ASME Boiler and Pressure Vessel Code, Section II, "Material Specifications," (1977 Edition through Summer 1978 Addenda).

ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, "Component Supports," (1977 Edition through Summer 1977 Addenda).

b. American Concrete Institute

ACI 349-76, "Code Requirements for Nuclear Safety-Related Concrete Structures," (through 1979 Supplement).

3.8.2.3 Load and Loading Combinations

The Primary Containment is designed to withstand all credible conditions of loading, including preoperational test loads, normal loads, severe environmental loads, extreme environmental loads, and abnormal loads. These loads are considered in the applicable load combinations to assure that the response of the structure will remain within the design limits prescribed in Subsection 3.8.2.5.

The loads and load combinations provided below are extracted from Reference 1. Loads and load combinations relative to the modifications implemented after start of commercial operation are contained in References 2 through 11.

a. <u>Design Loadings</u>

The loadings considered in the design of the drywell, absorption chamber and interconnecting elements include:

- loads caused by temperature and internal or external pressure conditions.
- Gravity loads from the vessels, appurtenances and equipment supports.
- Horizontal and vertical seismic loads acting on the structures.
- Live loads.
- Vent thrusts.
- Jet forces on downcomer pipes.
- Water loadings under normal and flooding conditions.
- The weight of contained gas in the vessels.
- The effect of unrelieved deflection under temporary concrete loads during construction.
- Restraint due to compressible material.
- Wind loads on the structures during erection.

b. <u>Description of Loads</u>

1. <u>Pressures and Temperatures Under Normal Operating Conditions</u>

During reactor operation the vessels will be subjected to temperatures up to 150°F at close to atmospheric pressure. The absorption chamber will also be subject to the loads associated with the storage of up to 91,000 cubic feet of water distributed uniformly within the vessel.

2. Pressures and Temperatures Under Accident Conditions

The drywell and the vent system are designed for an internal pressure of 44 psig coincident with a temperature of 292°F and for an internal pressure of 35 psig coincident with a temperature of 281°F. The 35 psig and 281°F have been considered to prevail for a period of 4 to 5 days as a design condition. The absorption chamber is designed for an internal pressure of 35 psig coincident with the loads associated with the storage of absorption pool water increased in volume up to 91,000 cubic feet and a temperature of 150°F.

3. Jet Forces

The drywell shell and closure head are designed to withstand jet forces of the following magnitudes in the locations indicated from any direction within the drywell:

| Location | Jet Force (Max.) | Interior Area Subjected to Jet Force |
|---|---|---|
| Spherical Partof Drywell | 566,000 pounds | 3.14 square feet |
| Cylinder and Sphere to Cylinder Transition | 466,000 pounds | 2.54 square feet |
| Closure Head | 16,000 pounds | 0.09 square feet |

These jet forces consist of steam and/or water at 300°F maximum in the impingement area. The jet forces do not occur simultaneously. However, a jet force is considered to occur coincident with internal design pressure and a temperature of 150°F.

The spherical and cylindrical parts of the drywell are backed up by reinforced concrete with a layer of compressible material and an air gap between the outside of the drywell and the concrete to allow for thermal expansion. It is assumed that local yielding will take place, but it has been established that a rupture will not occur. This assumption is discussed more fully in Section III-2.4 of Reference 1.

Where the shell is not backed up by concrete (closure head), the primary stresses resulting from the combination of loads previously defined does not exceed 0.9 times the yield point of the material at temperature.

However, the primary plus the secondary stresses are limited to three times the allowable stress values given in Table UCS-23, Section VIII, ASME Boiler and Pressure Vessel Code. Supporting data is available in the report, "Loads on Spherical Shells", prepared by CB&I following a series of load tests on spherical plates. This report is included as an Appendix in Reference 1.

The absorption chamber and vent system are designed to withstand jet force reactions associated with the design basis LOCA. The design reaction on each 24 inch diameter downcomer pipe is 21,000 pounds. Stresses resulting from these reactions are limited to ASME Code allowables.

4. <u>Gravity Loads to be Applied to the Drywell Vessel</u>

- The weight of the steel shell, jet deflectors, vents and other appurtenances.
- Loads from structural members used to support equipment.
- An allowance for the weight of the compressible material applied to the exterior of the vessel and as described in the B&R, Inc. report "Expansion of the Drywell Containment Vessel", which is included as an Appendix in Reference 1.
- The live load on the access opening: 11 tons or 150 pounds per square foot, whichever is more severe.
- The live load for the depth of water on the water seal at the top flange of the drywell with the drywell hemispherical head removed.
- The weight of contained gas during the tests.

- Dead and live loads on the welding pads provided on the inside of the containment sphere shoulders, spaced at 8 foot centers in each direction. Permanent loads are 200 pounds on each pad, with 800 pounds of live load on any two adjacent pads.

- A temporary load due to the pressure of fluid concrete which was placed directly against the compressible material attached to the exterior of the drywell and vents. The fluid concrete pressure was controlled by limiting the rate of placement per hour in order to have a pressure limit of 3 psi on the compressible material.

5. Gravity Loads to be Applied to the Absorption Chamber

- The weight of the steel shell including catwalk, vent header, downcomer pipes and other shell appurtenances.

- The absorption pool water stored in the vessel as specified above.

- The weight of contained air during the tests.

6. Lateral Load

The drywell vessel which was exposed above grade, prior to construction of the Reactor Building, was designed to withstand wind loads on the projected area of the circular shape in accordance with the height zones listed below. These loads were analyzed in combination with other loads applicable during this stage, with stresses limited to 133 percent of the ASME allowable stresses.

| Height Above Grade in Feet | Wind Load in Pounds per Sq. Foot |
|---|---|
| 0 - 30 | 15 |
| 30 - 50 | 18 |
| over 50 | 24 |

The effects of the lateral loads at the blanked off vessel penetrations were investigated.

7. Seismic Loads

A lateral static coefficient equal to 22 percent, and a vertical static coefficient equal to 10 percent, of the permanent gravity load was assumed as acting simultaneously with each other.

This load was taken concurrently with permanent gravity loads, accident pressure conditions and other lateral loads as shown in Figures 3.8-4 and 3.8-5. These values were based on studies and criteria described in Section 2.5.

The static coefficients listed were used by CB&I to develop the design of the drywell and absorption chamber. After completion of this design and fabrication of the vessels, John A. Blume & Associates were engaged by G.E.to perform a dynamic analysis of the structure under seismic conditions. The complete analysis performed by Blume has been included in Appendix III-2.4 (Item 3) in Reference 1. The results of these calculations list coefficients equal to those utilized by CB&I in their calculations, corroborating the adequacy of the seismic design performed by CB&I.

c. Loading Combinations Used in the Basic Design of the Drywell and Vent System

1. Case I - Initial Test Condition at Ambient Temperature at Time of Test

- Gravity load of vessel and appurtenances
- Design pressure
- The weight of contained air
- Lateral load due to wind or seismic forces whichever is more severe
- Vent thrusts
- Vertical seismic load

2. <u>Case II - Final Test Condition at Ambient Temperature at Time of Test</u>

- Gravity load of vessel and appurtenances
- Gravity load from equipment supports
- Gravity load of compressible material
- Gravity load of welding pads
- Design pressure
- Seismic loads
- Effect of unrelieved deflection under temporary concrete load
- Restraint due to compressible material
- Vent Thrusts

3. <u>Case III - Normal Operating Condition at Operating Temperature Range of 50°F to 150°F</u>

- Gravity load of vessel and appurtenances
- Gravity load from equipment supports
- Gravity load of compressible material
- Seismic loads
- Vent thrusts
- Restraint due to compressible material
- Gravity load on welding pads
- Effect of unrelieved deflection under temporary concrete load
- External pressure of 2 psig
- Live load on personnel air lock

4. Case IV - Refueling Condition with Drywell Hemispherical Head Removed, at Operating Temperature Range of 50°F to 150°F
   - Gravity load of vessel and appurtenances
   - Gravity load from equipment supports
   - Gravity load of compressible material
   - Gravity and live load on welding pads
   - Water load on water seal at top flange of drywell
   - Seismic loads
   - Effect of unrelieved deflection under temporary concrete load
   - Restraint due to compressible material
   - Vent thrusts
   - External pressure of 2 psig
   - Live load on access opening

5. Case V-Accident Condition at Temperature Listed Below
   - Gravity load of vessel and appurtenances
   - Gravity load from equipment supports
   - Gravity load of compressible material
   - Gravity load on welding pads
   - Seismic loads
   - Design Pressure: Maximum positive pressure of 44 psig at 292°F decaying to 35 psig at maximum temperature at 281°F, to maximum negative pressure of 2 psig at 205°F.
   - Effect of unrelieved defl8ection under temporary concrete load
   - Restraint due to compressible material
   - Vent thrusts
   - Jet forces

d. Load Combinations Used in the Basic Design of the Absorption Chamber

1. Case I - Initial and Final Test Condition at Ambient Temperature at Time of Test

   - Gravity load of vessel and appurtenances
   - Absorption pool at the operating maximum of 91,000 cubic feet of water
   - Seismic loads
   - Design pressure
   - Vent thrusts

2. Case II - Temporary Condition at Ambient Temperature During Construction

   - Gravity load of vessel and appurtenances
   - Seismic loads

3. Case III - Normal Operating Condition at Operating Temperature Range of 50°F to 150°F

   - Gravity load of vessel and appurtenances
   - Absorption pool at the operating minimum of 82,000 cubic feet of water
   - Seismic loads
   - Vent thrusts

4. Case IV - Accident Condition at 150°F Maximum

   - Gravity load of vessel and appurtenances
   - Absorption pool at the operating maximum of 91,000 cubic feet of water

- Seismic loads
- Design pressure of 35 psig
- Vent thrusts
- Jet forces on downcomer pipes

### 3.8.2.4 Design and Analysis Procedures

The design and analysis procedures described herein are those presented in Reference 1. Subsequent to the initial design, certain modifications were made to Primary Containment penetrations. The original design, modifications and analyses related to them are discussed in Subsection 3.8.2.4.3.

#### 3.8.2.4.1 Drywell

Primary Membrane Stresses

The membrane stresses are based on the assumption that the thin shell resists the imposed loads by direct stress only. In addition, for earthquake design, it has been assumed that the shell as a free standing circular cantilever beam of variable cross section. Stresses have been computed at various points along the vertical axis of the drywell as shown on Figures 3.8-6 and 3.8-7. The notations adopted in these calculations are defined as follows:

$T_1$ = Latitudinal force in pounds per inch of meridional arc length

$T_2$ = Meridional force in pounds per inch of arc length

$S_1$,$S_2$ = Unit stresses corresponding to $T_1$ and $T_2$ and are equal to $T_1$ or $T_2$ divided by t

W = Total gravity load above the plane, in pounds

P = Internal or external pressure in lbs/in$^2$.

R = Radius of the cylinder or sphere as applicable, in inches

t = Plate thickness in inches

q = Vertical angle between vertical axis and point in the shell being computed

The internal force per unit width is computed from the following relationships:

Cylindrical Portion of Drywell:

$T_1 = PR$ and $T_2 = PR/2$ for internal or external pressure

$T_2 = W/2\ p\ R$ for gravity loads

$T_2 = -T_1 = Meq/S$ for earthquake loads

$T_2 = Mw/S$ for wind loads

where Meq and Mw are the moments due to earthquake and wind, respectively, and S is the Section Modulus of the Section.

Spherical Portion of the Drywell:

$T_1 = T_2 = PR/2$ for internal or external pressure

$T_2 = -W/2\ p\ R\ \sin^2 q$ ; $T_1 = -PR\cos q\ \ -T_2$ for gravity loads

$T_2 = -T_1 = Meq/\ p\ R^2(\sin^3 q)$ for earthquake load

$T_2 = T_1 = Mw/\ p\ R^2(\sin^3 q)$ for wind load

Load Deflection Tests

Design pressure for the drywell requires a relatively thin walled steel vessel. However, the vessel has relatively little capability to resist concentrated jet forces. Such loads are, however, readily accepted by the massive concrete shield which surrounds the vessel. Accordingly, the space between the steel drywell vessel and the concrete shield outside has to be sufficiently small so that, although local yielding of the steel vessel can occur under concentrated forces, yielding to the extent causing rupture will be prevented. Space has been provided to allow the drywell to expand when in its stressed condition in order for it to function as a pressure vessel. In addition, the vessel is subject to thermal expansion due to exposure to operating and possible accident temperatures which are significantly higher than ambient.

In order to investigate whether or not a steel shell could deflect up to three inches locally without failure as a result of a concentrated load, CB & I conducted a series of tests on a steel plate formed to simulate a portion of the drywell vessel. The tests also provided data on loading required to produce a given deflection, and the strain at various points of the shell. In performing these tests, it was assumed that permanent deformation is not considered as failure.

The basic test section was designed and fabricated to simulate a 70 foot diameter sphere. The material and plate thickness used were typical of the type used in pressure suppression containment system applications. By modifying the basic section through the addition of an 18 inch diameter fitting with insert type reinforcing, a typical penetration was simulated. Again by the removal of the insert type fitting and the insertion of an 18 inch diameter fitting with pad type reinforcing, another typical penetration was simulated.

Step by step procedures, description of the tests, as well as load deflection and load strain curves are included in the CB & I report "Loads on Spherical Shells" in Appendix III-2.4 (Item 2) of Reference 1. The results of these tests indicate that spherical steel shells of this diameter and thickness, as well as fittings with insert type reinforcing located in a spherical steel shell are capable, under concentrated loading, of withstanding a substantial localized deflection without failure. Graphs of the theoretical radial strain in the shell, calculated assuming the shell to be a membrane, are included in this report. They indicate that the experimental data conforms rather well to the theoretical values. This confirms that the shell was acting in close conformity to the approximate theoretical mode.

Expansion of the Drywell Containment Vessel

The load deflection tests performed by CB&I on steel plates provided the basis for selecting three inches as the maximum acceptable space between the cold drywell shell and the biological concrete shield which surrounds it.

The three inch space precludes the use of a conventional forming system for the inner face of the concrete shield.

The approach taken was to fill the space permanently with a material having sufficient compressibility to permit the expected vessel movement and yet be rigid enough so as not to deform under the fluid pressure of concrete. This pressure can be controlled by limiting the rate of placement of the concrete.

To eliminate the need for a continuous internal pressure in order to prevent compressive forces on the vessel, an inelastic compressible material was selected; such a material can be permanently compressed once by simulating the conditions causing the greatest vessel expansion. The residual air gap created by the inelastic compression of the material will then offer no resistance to subsequent repetitions of vessel expansion.

After careful consideration, testing, and investigations as to the type of material to be utilized, an asbestos fiber magnesite cement product was selected. To determine the required minimum thickness of the material, it was necessary to establish the extent to which it was compressed. This was determined by the expansion of the vessel associated with its highest postulated temperature for any future operating or accident condition, and by the procedure planned for expanding the vessel to create an air gap larger than required to accommodate any future conditions.

Information and discussions pertaining to the performance, design and analysis aspects of the inelastic compressible material is given in Subsection 3.8.2.4.3.

An internal pressure of 35 psig (saturated steam pressure at a temperature of 281°F) resulted in an expansion which exceeded postulated accident or operating expansion, and hence, was a criterion for determining spacing dimensions.

At the most critical location, the point on the sphere most distant from the bottom embedment, thermal expansion was expected to be about 1.06 inches. Tests on the spacing material to measure the pressure required to reduce its thickness by this amount, and also taking into account the compression resulting from the fluid concrete pressure before setting, indicated an initial thickness requirement of about 2 1/2 inches. The design pressure transmitted to the concrete shield wall by the spacing material during initial expansion of the vessel would be 20 psi, which is tolerable from the standpoint of the concrete strength. Some tolerance on thickness of the compressible material had to be allowed. A workable limit of ±1/4 inch was chosen. Since the design pressure on the wall assumed 2 1/2 inches minimum, thickness of 2 3/4 inches ±1/4 inch was specified.

In considering the acceptability of the three inch gap as a maximum between the steel vessel and the concrete shield, it should be noted that this distance would be reduced by: the compression of the material under the fluid concrete pressure; the thermal expansion of the vessel in going from ambient temperature during construction to an operating temperature at which the design accident might occur; and the fully compressed thickness of the material. These conditions were expected to reduce the three inches to well below the 3.125 inch minimum failure deflection of the CB&I jet load simulation tests, particularly in view of the conservative approach used in those tests. It was thus concluded that a gap of three inches between the drywell vessel and the biological concrete shield would be satisfactory.

The construction schedule required that the compressible material be applied to the exterior of the vessel prior to the construction of the concrete shield wall.

The mixing and foam injection, as well as the application procedure for the compressible material to the vessel was performed in accordance with that developed by the manufacturer, All Purpose Fireproofing Corp. The material was built up in three coats to make a total thickness of 2 3/4 inches ±1/4 inch for the upper hemisphere. Since the lower hemisphere of the cylindrical section will have less total expansion, 2 1/2 inches ±1/4 inch of the compressible material was applied over their surfaces. A polyethylene sheet reinforced with glass fibers was used to prevent bonding of the spacing material and the concrete. The actual application was completed in about two weeks.

After completion of the material application, any damages noted were repaired. Testing and inspection services were provided to assure that the quality and workmanship were as required.

After the biological concrete shield wall was poured against the compressible material and cured, the vessel was prepared for the expansion operation. Expansion of the vessel was accomplished by pressurizing with heated air by means of portable compressors, electric duct heaters and fans placed at various locations within the vessel.

A temperature recorder was used to monitor temperature. Several of the existing vessel penetrations, consisting of pipes welded into the vessel and extending out through the concrete shield wall through sleeves, were used to monitor vessel expansion.

The expansion operation was conducted as planned, and pressure, temperature and expansion recorded throughout the procedure. The concrete shield wall exterior was examined periodically and particularly at maximum temperature and pressure; no evidence of distress was observed. An inspection of the interior of the drywell immediately after the expansion operation and again some 12 hours later gave no evidence of distress. The maximum displacement recorded during expansion was 0.61 inches which was less than the time temperature performance value calculated by computer program method. This measurement together with the favorable results of the examination of the shield wall and drywell vessel interior corroborated the assumptions made in the drywell design. Complete step by step procedures, initial criteria and conclusions drawn from this expansion procedure are included in the B&R, Inc. report "Expansion of the Drywell Containment Vessel" in Appendix III-2.4 (Item 1) of Reference 1. See also Subsection 3.8.2.4.3.

Maximum Primary Membrane Stresses in the Shell

The maximum primary membrane stresses in the shell result from the following combination of loads.

Internal pressure of **44 psig**, dead load of the shell and appurtenances lateral and vertical seismic loads, gravity load on welding pads and gravity load of the compressible material. The internal pressure load causes by far the greatest stress.

The maximum stress is 19,200 psi which is less than that allowed by the code. It occurs in the cylindrical portion of the drywell. Other stresses computed at other points along the drywell are lower in magnitude.

In addition to maximum stresses computed for the cylindrical and spherical portions of the drywell, stresses have been computed on the elliptical head of the vessel taking into account the effect of jet forces since this portion of the vessel is not backed up by concrete. The maximum stress on the head and been found to be 29,340 psi and it results from jet forces combined with an internal pressure of 44 psig. The design specification allowance for this loading combination is 31,500 psi.

Since the personnel and equipment hatch had no concrete backing to take the effect of jet forces, this portion of the drywell as well as its components was investigated and designed for jet forces in conjunction with the other load combinations as set forth in Figures 3.8-4 and 3.8-5. The effect of eccentricities on possible jet forces was also analyzed and the design provided reinforcements and stiffeners as required to maintain stresses within specified limits.

In conclusion, the design of the personnel and equipment hatch is adequate, and provides a safe and well engineered structure.

Flooded Condition

The drywell vessel has been analyzed for its ability to withstand loading resulting from partial flooding and for maximum flooding to El. 74'-6" (see Figure 3.8-8).

In each case, the maximum stress computed for various locations on the shell are below the ASME Code allowables. In addition, critical buckling of the vessel under flooded conditions has been analyzed. The results of this analysis show that there is ample margin of safety under either flooding condition.

Buckling Considerations

The drywell shell must be capable of resisting the compressive stresses resulting from the external pressure, the dead load of the shell and appurtenances, the dead load of the compressible material, the live load on the access and beam loads, the gravity loads on the weld pads, plus the wind or seismic loads. These loads produce uniaxial compressive stresses of varying magnitude at different points along the drywell shell.

Section VIII of the ASME B&PV Code (1950), permits an allowable compressive stress of 1,800,000 ($t^2/R$) for uniaxial compression. Later editions of the code do not include this equation as such, but include tables for allowable external pressures which are based on this allowable.

The state of stress at any point in the spherical shell may be expressed as a biaxial compressive stress plus a uniaxial compression.. By combining the $T_1$ and $T_2$ stresses acting at the point algebraically, the allowable compressive stress is then given by the relationship:

$$(T_2 - T_1)/1.8 \text{ X } 10^6(t^2/R) + T_1/9 \text{ x } 10^5(t^2/R)\pounds 1,$$

where $T_1$ and $T_2$ are compressive stresses. This relationship applies to buckling of the spherical shell under biaxial compression. Also:

$$T_2/1.8 \text{ x } 10^6(t^2/R)\pounds 1,$$

which is the axial buckling of the cylindrical shell.

The stress values at the different points along the shell are summarized in Table 3.8-2 and are below the ASME allowables.

Summary

Since all possible loads, as well as their combinations, have been taken into consideration, and the maximum stresses computed are all within the design specifications and ASME Boiler and Pressure Vessel Code allowables, the drywell design is adequate.

3.8.2.4.2 Torus

Following the original design of the facility, additional design, analysis and modification work was performed for the torus under the Mark I Containment Systems Evaluation Program. These efforts are described in detail in References 2 through 11. The general analytical procedures and computer techniques utilized in the design modifications of the suppression chamber are provided in Reference 10. The discussion that follows was extracted from Reference 1, the Primary Containment Design Report.

Primary Membrane Stresses

The absorption chamber is supported on twenty pairs of columns located on the inner and outer peripheries and equally spaced. An internal ring girder of variable cross section has been provided at each of the supporting points to reduce local stresses and to add stiffness to the section. Although the principal stresses computed on the absorption chamber were circumferential, detailed analyses have been performed to determine the magnitude of localized stresses at the points of column and downcomer supports, vents, etc., to determine the need for and provide additional stiffeners and reinforcing as required.

Tests specifically for this application of the material conducted by the United States Testing Company, were to determine increments of pressure required to cause increments of deflection up to 50 percent of sample thickness. The samples were made using the production equipment and procedure to spray onto metal surfaces; the tests were made with samples in vertical and horizontal positions, at ambient temperature and at 300°F. Material loss after compaction was measured on test panels compressed in the vertical position; loss was about 1 percent of compressed sample weight; it was observed that loss was occurring at the break in the samples at the perimeter of the compression shoe, a discontinuity which would not occur in service. The reduction in thickness of the samples results principally from the collapse of the cellular structure impacted by the foam and maintained by the magnesite cement, however, some elastic compression of the asbestos fibers would be expected. The test samples were retained by the testing agency for periodic observation of rebound; rebound stabilized at 20 percent of total deflection.

The tests and evaluations indicated that the foamed asbestos fiber magnesite cement product has the required compression characteristics and stability, and would be unaffected by long term exposure to radiation and heat.

Further evaluation of the design of Primary Containment penetration is presented in References 13 and 14.

3.8.2.5 Structural Acceptance Criteria

The Structural Acceptance Criteria relating the design and analysis results for the loads and load combinations given in Subsection 3.8.2.3 to the allowables, is presented in Subsection 3.8.2.4 and other referenced documents. The Basic Design phase of the Containment System is given in Subsection 3.8.2.4 and the references listed in Subsection 3.8.6. These reference documents must be addressed to obtain complete information.

A summary of allowable stresses considered in the original design of the facility used in conjunction with certain seismic loading combinations is given in Table 3.8-3.

### 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. The coating will be inspected again during the 18th. refueling outage (Year 2000). 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. GPU Nuclear 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 42 provides the evaluation of the latest drywell UT inspections through the next scheduled inspection.

GPUN will notify NRC prior to implementing any changes to the drywell thickness measurement inspection program (Reference 43).

### 3.8.5.6 Materials, Quality Control and Special Construction Techniques

The primary materials of construction are concrete and reinforcing steel. Their descriptions and basic quality control procedures are discussed in Subsection 3.8.4.6.

There were no special construction techniques.

### 3.8.5.7 Testing and Inservice Surveillance Requirements

The ability of the drywell and torus to transmit pressure associated loads to the soil media via the foundations has been demonstrated by the structural integrity test described in Subsection 3.8.2.7.

No preoperational or inservice surveillance tests are required for the other Category I structure foundations.

### 3.8.6 References

(1) Oyster Creek Nuclear Power Plant Unit No. 1, Facility Description and Safety Analysis Report, Docket No. 50-219, Amendment No. 15, Primary Containment Design Report, September 11, 1967.

(2) NUREG-0661. Safety Evaluation Report, Mark I Containment Long Term Program Resolution of Generic Technical Activity A-7. July 1980.

(3) NUREG/CR-1083, LBL-6754. Aslam, M; Godden, W.G.; and Scalise, T. Sloshing of Water in Annular Pressure Suppression Pool of Boiling Water Reactors under Earthquake Ground Motions. Lawrence Berkeley Laboratory for U.S.N.R.C. October 1979.

(4) NUREG/1082, LBL-7984. Aslam, M; Godden, W.G.; and Scalise, T. Sloshing of Water in Torus Pressure-Suppression Pool of Boiling Water Reactors under Earthquake Ground Motions. Lawrence Berkeley Laboratory for U.S.N.R.C. October 1979.

(5) NUREG-0408. Mark I Containment Short Term Program: Safety Evaluation Report. December 1977.

(6) NEDO-21888 (Revision 2). Mark I Containment Program: Load Definition Report. November 1981.

(7) NEDO-24572 (Revision 2). Mark I Containment Program: Plant Unique Load Definition Oyster Creek Nuclear Generating Station. July 1982.

(8) NEDO-24583-1. Mark I Containment Program Structural Acceptance Criteria: Plant-Unique Analysis Application Guide. October 1979.

(9) NEDC-23702-P. Arain, S.M. Mark I Containment Program: Seismic Slosh Evaluation. March 1978.

(10) MPR-733. Oyster Creek Nuclear Generating Station Mark I Containment Long-Term Program: Plant-Unique Analysis Report Suppression Chamber and Vent System. August 1982.

(11) MPR-734. Oyster Creek Nuclear Generating Station, Mark I Containment Long Term Program: Plant-Unique Analysis Report Torus Attached Piping. August 1982.

(11a) MPR-722. Oyster Creek Nuclear Generating Station, Mark I Containment Long Term Program: Plant-Unique Analysis Supplemental Report. July 1983.

(12) Von Karman, "The Buckling of Spherical Shells by External Pressure," Pressure Vessel and Piping Design, Collected Papers, ASME, 1960, pp. 633 to 640.

(13) Oyster Creek Nuclear Power Plant Unit No. 1, Facility Description and Safety Analysis Report, Docket No. 50-219, Amendment No. 50, Primary Containment Penetration Design, March 1969.2

(14) Oyster Creek Nuclear Power Plant Unit No. 1, Facility Description and Safety Analysis Report, Docket No. 50-219, Amendment No. 51, Supplemental Information Regarding Primary Containment Penetrations, March 21, 1969.

(15) Letter from I. R. Finfrock, Jr. (JCP&L) to George Lear (NRC), dated November 1, 1977, on Torus Pool Swell-Relief Valve Actuation.

(16) Letter from George Lear (NRC) to I.R. Finfrock, Jr. (JCP&L), dated March 24, 1977, Summary of March 4, 1977 Meeting Results, Related to Torus Inspection for Corrosion and Staggered Relief Valve Set Points.

(17) Letter EATJM-190, March 22, 1977, Report on Steam Vent Cleaning Phenomenon.

(18) Letter EATJM-29, January 10, 1977, Report on Steam Vent Clearing Phenomenon.

(19) Letter EA-76-686, July 16, 1976, Oyster Creek Torus Shell Thickness Evaluation.

(20) Drwg 4104-1 Biological Shield Wall

(21) Drwg 4205-1 Biological Shield Wall, Sections & Details

(22) Drwg 4069-4 Radial Beam Framing (Inside Drywell)

(23) Drwg 2063-4 General Arrangement-Reactor Building Sections (from Print Book; shows drywell internals).

(24) Drwg 4049-7 Reactor Building Floor Plan & Sections (Outside Drywell Shell).

(25) Drwg CBI 34-3 Floor Framing Bracket

(26) Drwg CBI 35-3 Floor Framing Hanger

(27) Calculations 19-62 Drywell Steel Framing at El. 46'-08" to 19-102

(28) Calculations 29-19

(29) Calculations 9-126 to 9-304

(30) Calculations 21-32 to 21-56

(31) Calculations 6-1 to 90

**(32) Letter from D.A. Ross (JCP&L) to B.H. Grier (NRC:I&E), dated December 7, 1979, Re: IE Bulletin 79-02**

(33) Letter from D.A. Ross (JCP&L) to B.H. Grier (NRC:I&E), dated August 3, 1979, Re: IE Bulletin 79-02.

(34) Letter from D.A. Ross (JCP&L) to B.H. Grier (NRC:I&E), dated July 6, 1979, Re: IE Bulletin 79-02.

(35) Letter from P.B. Fiedler (GPUN) to D.M. Crutchfield (NRC: DRL), dated November 2, 1983, Re: IE Bulletin 80-11.

(36) Letter from P.B. Fiedler (GPUN) to D.M. Crutchfield (NRC: DRL), dated August 11, 1983, Re: IE Bulletin 80-11.

(37) Letter from I.R. Finfrock, Jr. (JCP&L) to B.H. Grier (NRC: I&E), dated September 19, 1980, Re: IE Bulletin 80-11.

(38) Calculations, Sheets 9-1 to 9-25, Frame 37.

(39) Drawings 4075-7, 4049-7, 4103-4.

**APPLICANT'S EXHIBIT 39**

GE Nuclear Energy

990-2174

DEC 14 1992

December 11, 1992

To: Dr. Stephen Tumminelli
Manager, Engineering Mechanics
GPU Nuclear Corporation
1 Upper Pond Road
Parsippany, NJ 07054

Subject: Sandbed Local Thinning and Raising the Fixity Height Analyses (Line Items 1 and 2 in Contract # PC-0391407)

Dear Dr. Tumminelli:

The attached letter report documents the results of subject analyses. The original purchase order called for the analyses to be conducted on a spherical panel model rather than on the full pie slice model. However, the results are more useful when conducted on the full pie slice model since in that case no interpretation is required regarding the relationship between the spherical panel results and the pie slice model results. The pie slice model we have used in these studies has the refined mesh in the sandbed region.

A 3.5" PC Disk containing three ANSYS input files (0.636" case, 0.536" case and 1 foot wall case) is also enclosed with this letter. The detailed calculations have been filed in Chapter 10 of our Design Record File No. 00664.

This transmittal completes the scope of work identified in the subject PO. If you have any questions on the above item, please give me a call.

Sincerely,

H.S. Mehta, Principal Engineer
Materials Monitoring & Structural Analysis Services
Mail Code 747; Phone (408) 925-5029

Attachment: Letter Report

cc: D.K. Henrie (w/o Attach.)
J.M. Miller (w/o Attach.)
S. Ranganath (w/o Attach.)

HSMOC-57.wp

990-2174

# LETTER REPORT ON ADDITIONAL SANDBED REGION ANALYSES

## 1.0 SCOPE AND BACKGROUND

Structural Analyses of the Oyster Creek drywell assuming a degraded thickness of 0.736 inch in the sandbed region (and sand removed) were documented in GENE Report Numbers 9-3 and 9-4. A separate purchase order was issued (Contract # PC-0391407) to perform additional analyses. The PO listed the additional analyses under two categories: Line Item 001 and Line Item 002. This letter report documents the results of these analyses.

The additional analyses are the following:

(1) Investigate the effect on the buckling behavior of drywell from postulated local thinning in the sandbed region beyond the uniform projected thickness of 0.736" used in the above mentioned reports (Line Item 001).

(2) Determine the change in the drywell buckling margins when the fixity point at the bottom of the sandbed is moved upwards by ≈ 1 foot to simulate placement of concrete (Line Item 002).

The original PO called for the Line Item 001 analyses to be conducted on a spherical panel. The relative changes in the buckling load factors were to be assumed to be the same for the global pie slice model. However, the mesh refinement activity on the global pie slice model and the availability of work station, has given us the capability to conduct the same analyses on the global pie slice model itself, thus eliminating the uncertainties regarding the correlation between the panel model and the pie slice model.

All of the results reported in this report are based on the pie slice model with a refined mesh in the sandbed region.

## 2.0 LINE ITEM 001

Figure 1a shows the local thickness reductions modeled in the pie slice model. A locally thinned region of ≈ 6"x12" is modeled. The thickness of this region is 0.636" in one

990-2174

case and 0.536" in the other case. The transition to the sandbed projected thickness of 0.736" occurs over a distance of 12" (4 elements).

The various thicknesses indicated in Figure 1a were incorporated in the pie slice model by defining new real constants for the elements involved. The buckling analyses conducted as a result of mesh refinement indicated that the refueling loading condition is the governing case from the point of view of ASME Code margins. Therefore, the stress and buckling analyses were conducted using the refueling condition loadings. The center of the thinned area was located close to the calculated maximum displacement point in the refueling condition buckling analyses with uniform thickness of 0.736 inch. Figure 1b shows the location of the thinned area in the pie slice model.

2.1 0.536 Inch Thickness Case

Figures 2 through 5 show the membrane meridional and circumferential stress distributions from the refueling condition loads. As expected, the tensile circumferential stress (Sx in element coordinate system) and the compressive meridional stress (Sy in element coordinate system) magnitudes in the thinned region are larger than those at the other edge of the model where the thickness is 0.736 inch. However, this is a local effect and the average meridional stress and the average circumferential stress is not expected to change significantly.

Figures 6 and 7 show the first buckling mode with the symmetric boundary conditions at both the edges of the model (sym-sym). This mode is clearly associated with the thinned region. The load factor value is 5.562. The second mode with the same boundary conditions is also associated with the thinned region. Figure 8 shows the buckled shape. The load factor value is 5.872.

Next, buckling analyses were conducted with the symmetric boundary conditions specified at the thinned edge and the asymmetric boundary conditions at the other edge (sym-asym). The load factor of the first mode for this case was 5.58. Figure 9 shows the buckling mode shape. It is clearly associated with the thinned region. Figure 10 shows the buckled mode shape with asymmetric boundary conditions at the both edges (asym-asym). As expected, the load factor for this case is considerably higher (7.037).

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Thus, the load factor value of 5.562 is the lowest value obtained. The load factor for the same loading case (refueling condition) with a uniform thickness of 0.736" was 6.141. Thus, the load factor is predicted to change from 6.141 to 5.562 with the postulated thinning to 0.536".

2.2 0.636 Inch Thickness Case

Figures 11 through 14 show the membrane meridional and circumferential stress distributions from the refueling condition loads. As expected, the tensile circumferential stress (Sx in element coordinate system) and the compressive meridional stress (Sy in element coordinate system) magnitudes in the thinned region are larger than those at the other edge of the model where the thickness is 0.736 inch. However, this is a local effect and the average meridional stress and the average circumferential stress is not expected to change significantly.

Figures 15 and 16 show the first buckling mode with the symmetric boundary conditions at both the edges of the model (sym-sym). This mode is clearly associated with the thinned region. The load factor value is 5.91.

Next, buckling analysis was conducted with the symmetric boundary conditions specified at the thinned edge and the asymmetric boundary conditions at the other edge. The load factor of the first mode for this case was 5.945. Figure 17 shows the buckling mode shape. It is clearly associated with the thinned region. Based on the results of 0.536" case, the load factor for asym-asym case is expected to be considerably higher.

Thus, the load factor value of 5.91 is the lowest value obtained. The load factor for the same loading case (refueling condition) with a uniform thickness of 0.736" was 6.141. Thus, the load factor is predicted to change from 6.141 to 5.91 with the postulated thinning to 0.636".

2.3 Summary

The load factors for the postulated 0.536" and 0.636" thinning cases are 5.562 and 5.91, respectively. These values can be compared to 6.141 obtained for the case with a uniform sandbed thickness of 0.736 inch.

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## 3.0 LINE ITEM 002

The objective of this task was to determine the change in the drywell buckling margins when the fixity point at the bottom of the sandbed is moved upwards by ≈ 1 foot to simulate placement of concrete. The elements in the sandbed region are approximately 3-inch square. Thus the nodes associated with the bottom four row of elements (nodes 1027 through 1271, Figure 18) were fixed in all directions.

The buckling analyses conducted as a result of mesh refinement indicated that the refueling loading condition is the governing case from the point of view of ASME Code margins. Therefore, the stress and buckling analyses were conducted using the refueling condition loadings. Figure 19 through 22 show the membrane meridional and circumferential stress distributions from the refueling condition loads. Figure 23 shows the calculated average values of meridional and circumferential stresses that are used in the buckling margin evaluation.

Figure 24 shows the first buckling mode with sym-sym boundary conditions. The load factor for this mode is 6.739. The load factor with asym-sym boundary conditions is 6.887 and the mode shape shown in Figure 25. It is clear that the sym-sym boundary condition gives the least load factor. Figure 26 shows the buckling margin calculation. It is seen that the buckling margin is 5.3% compared to 0% margin in the base case calculation.

To summarize, the load factor changes to 6.739 for the refueling condition when the fixity point at the bottom of the sandbed is moved upwards by ≈ 1 foot. This results in an excess margin of 5.3% above that required by the Code.

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**GPU Nuclear** **Calculation Sheet**

| Subject | Calc No. | Rev. No. | Sheet No. of |
|---|---|---|---|
| Oyster Creek Drywell | | | |

| Originator | Date | Reviewed by | Date |
|---|---|---|---|
| M. Yekta | 11/23/92 | | |

## Proposed Local Thinning in the Refined Global Pie Slice

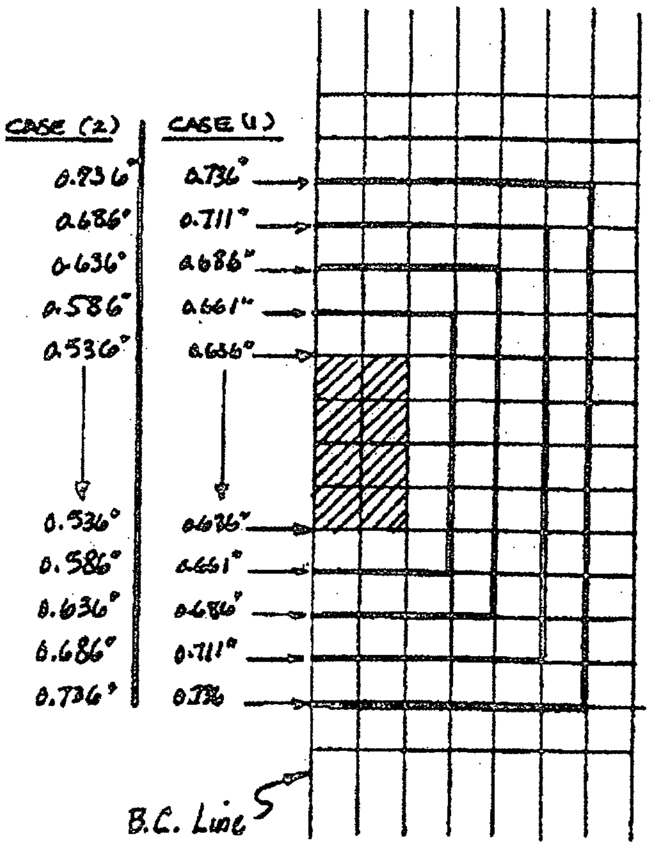


FIGURE 1a

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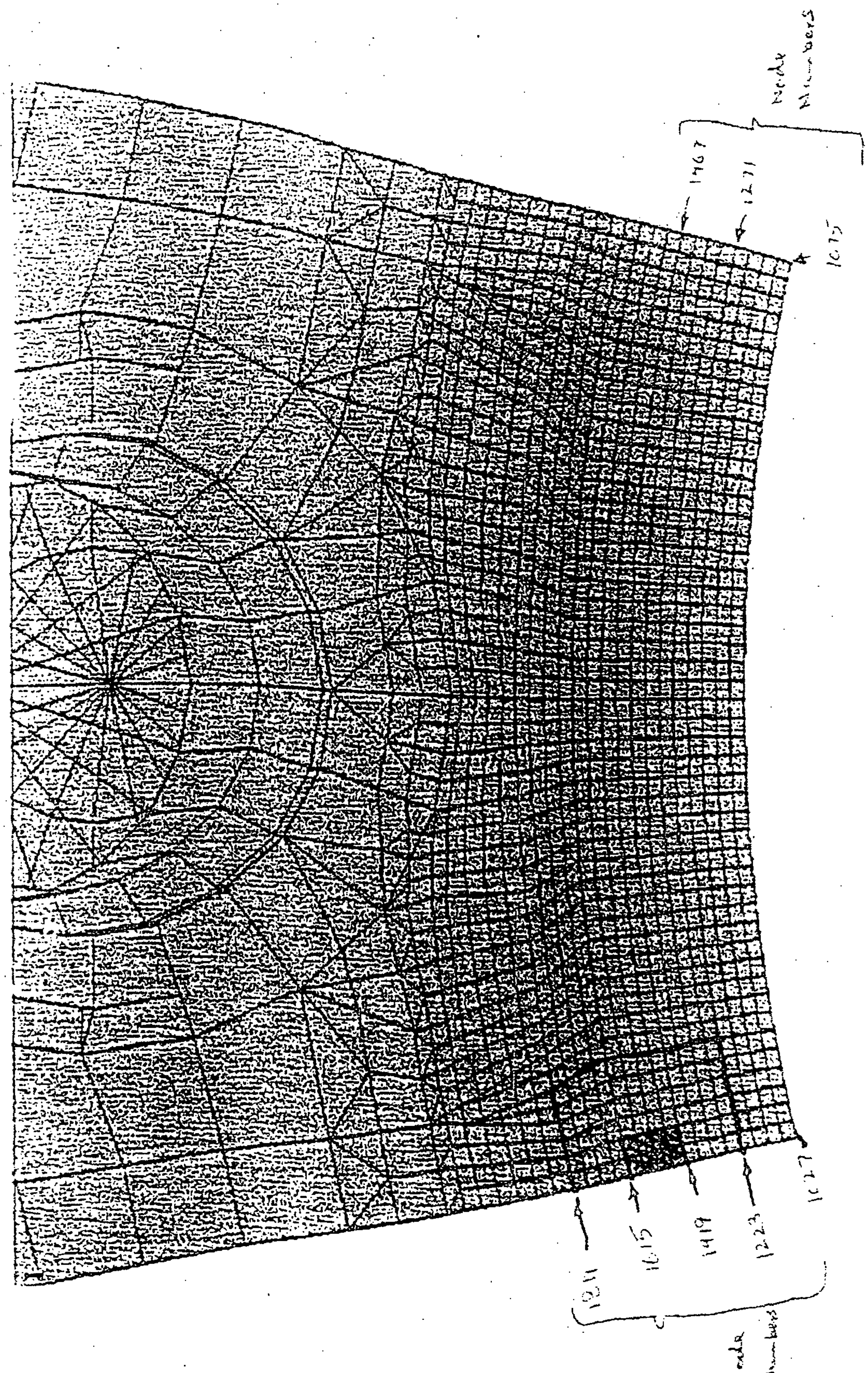
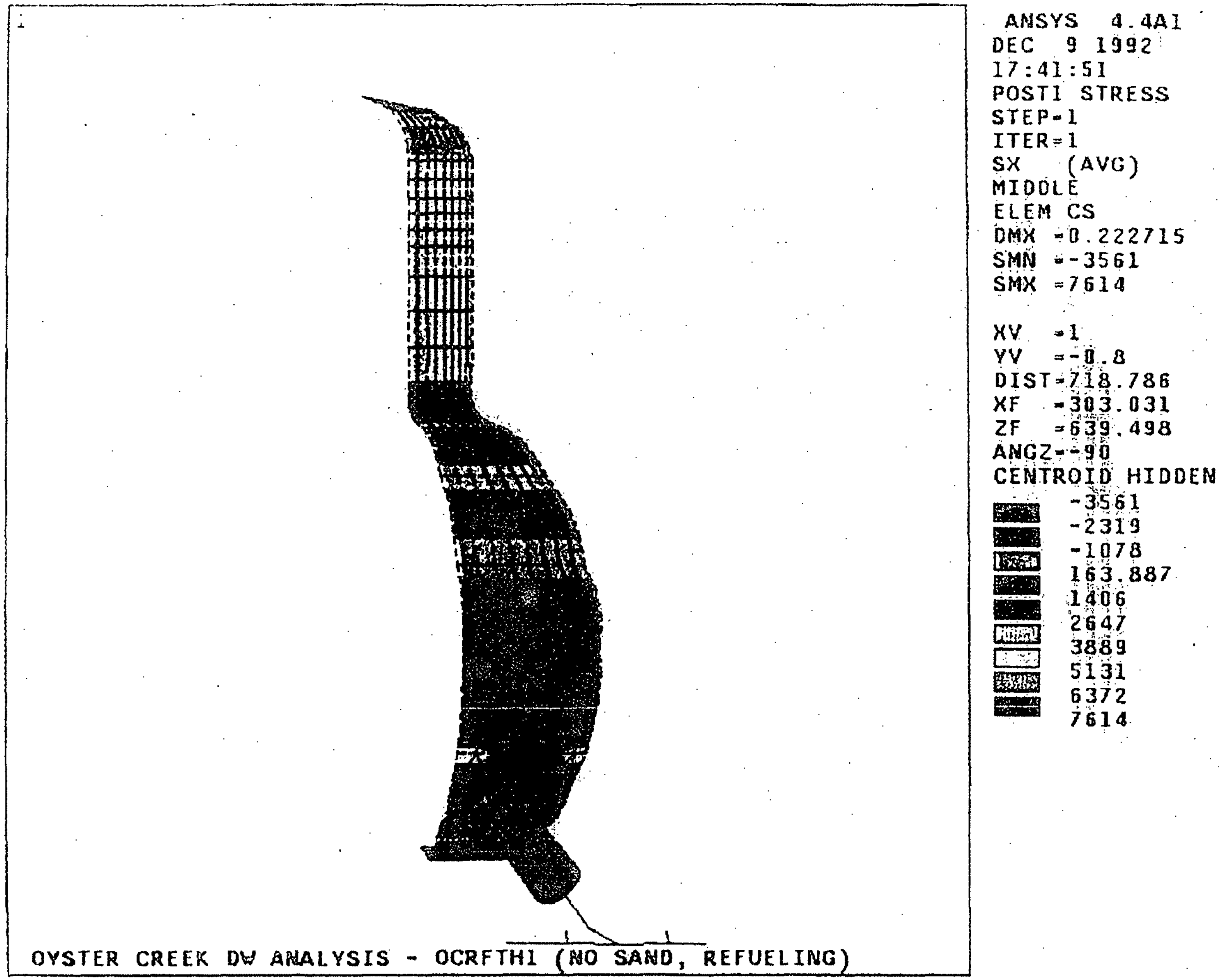



FIGURE 1b

FIGURE 2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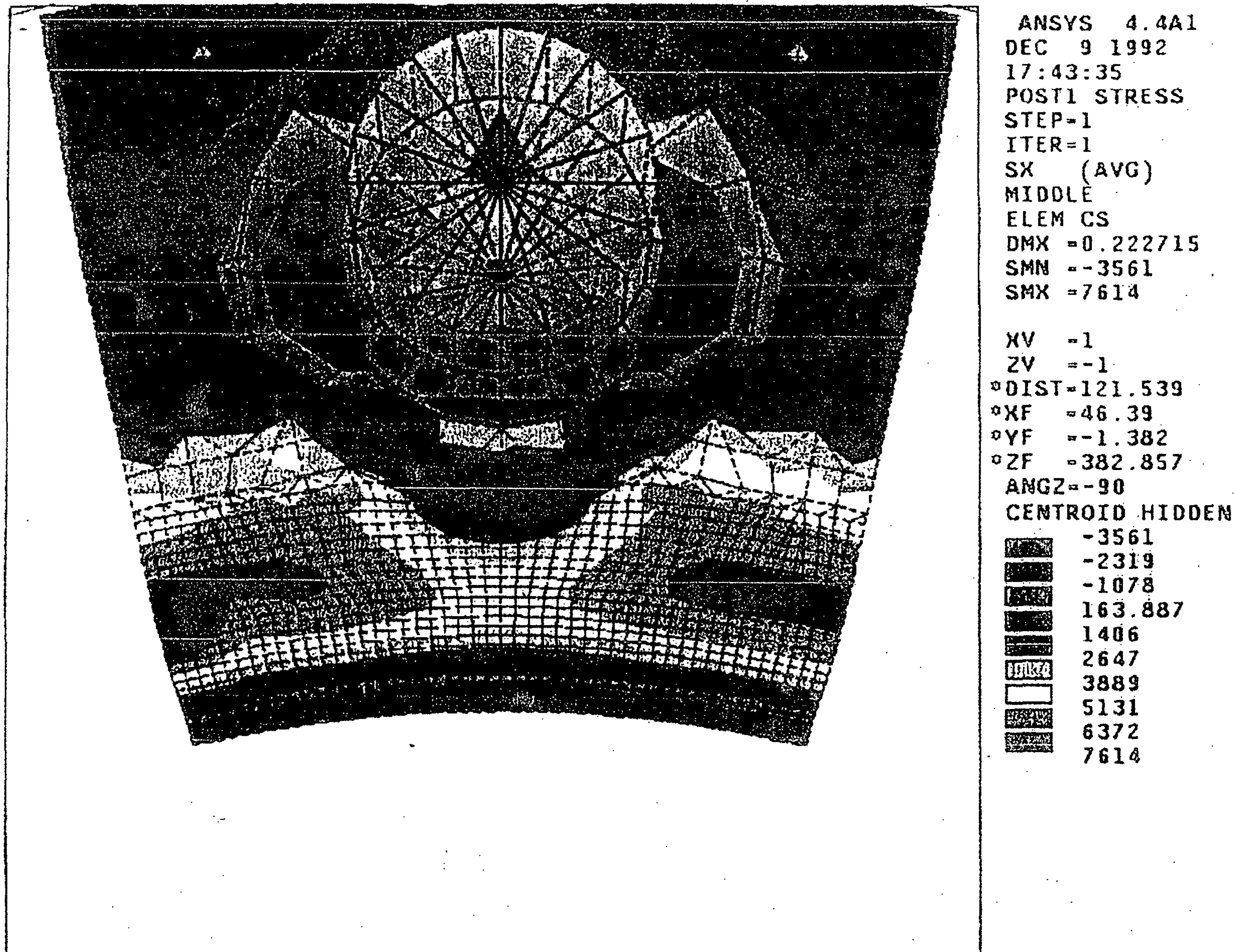
OYSTER CREEK DW ANALYSIS - OCRFTHI (NO SAND, REFUELING)

FIGURE 3




OYSTER CREEK DW ANALYSIS - OCRFTH1 (NO SAND, REFUELING)

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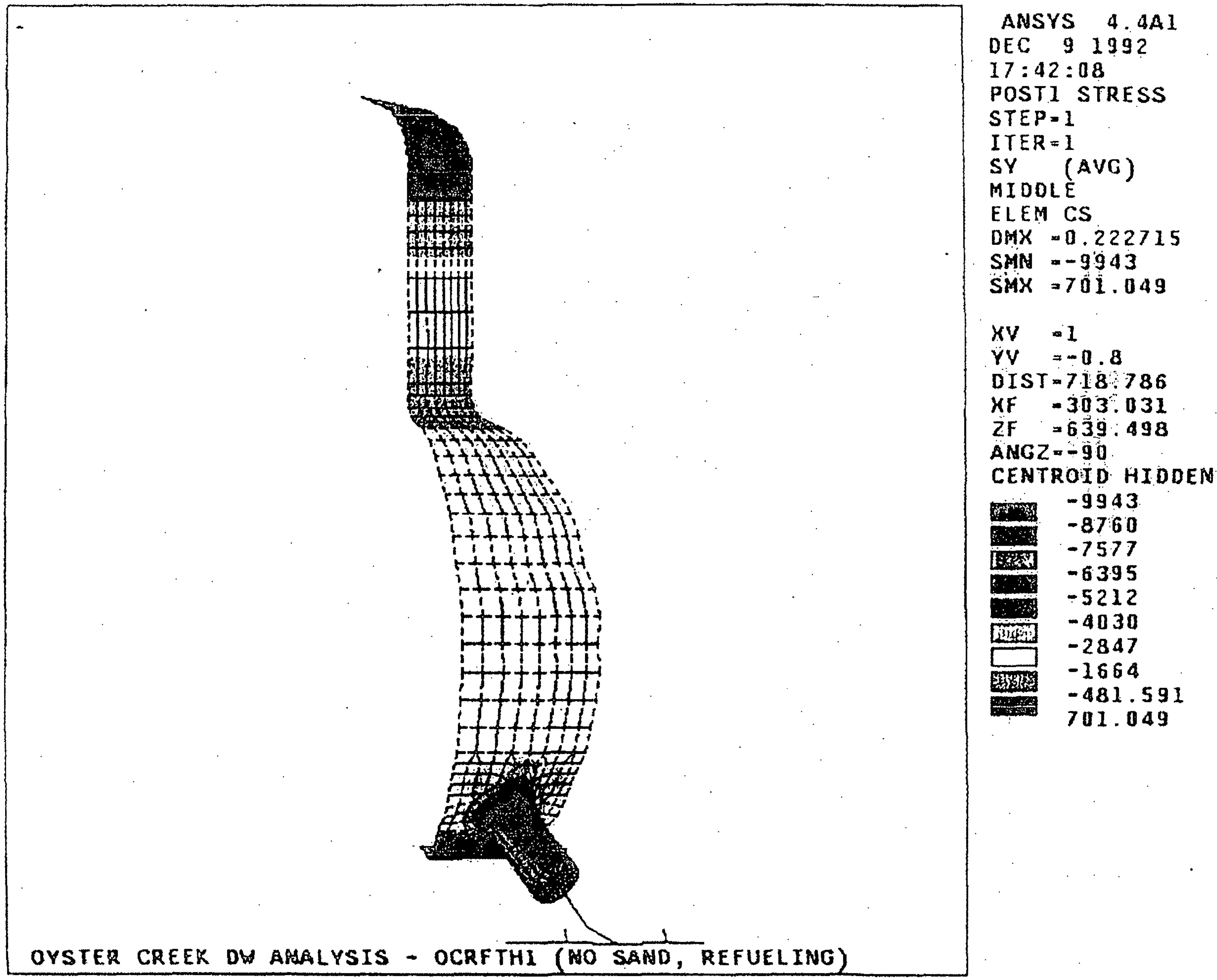
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ANGZ=-90
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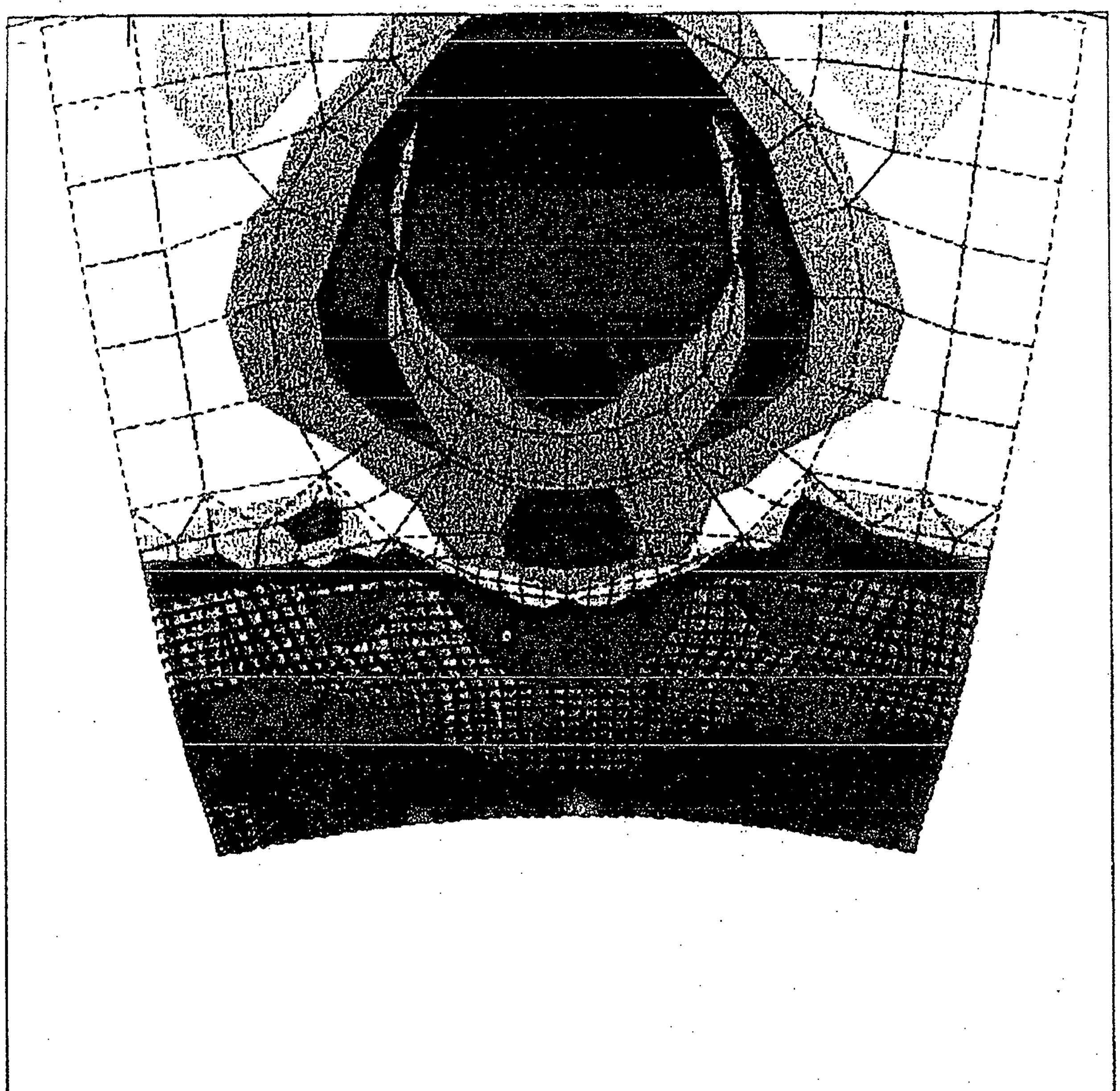
OYSTER CREEK DW ANALYSIS - OCRFTH1 (NO SAND, REFUELING)

FIGURE 4

FIGURE 5



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OYSTER CREEK DW ANALYSIS - OCRFTH1 (NO SAND, REFUELING)

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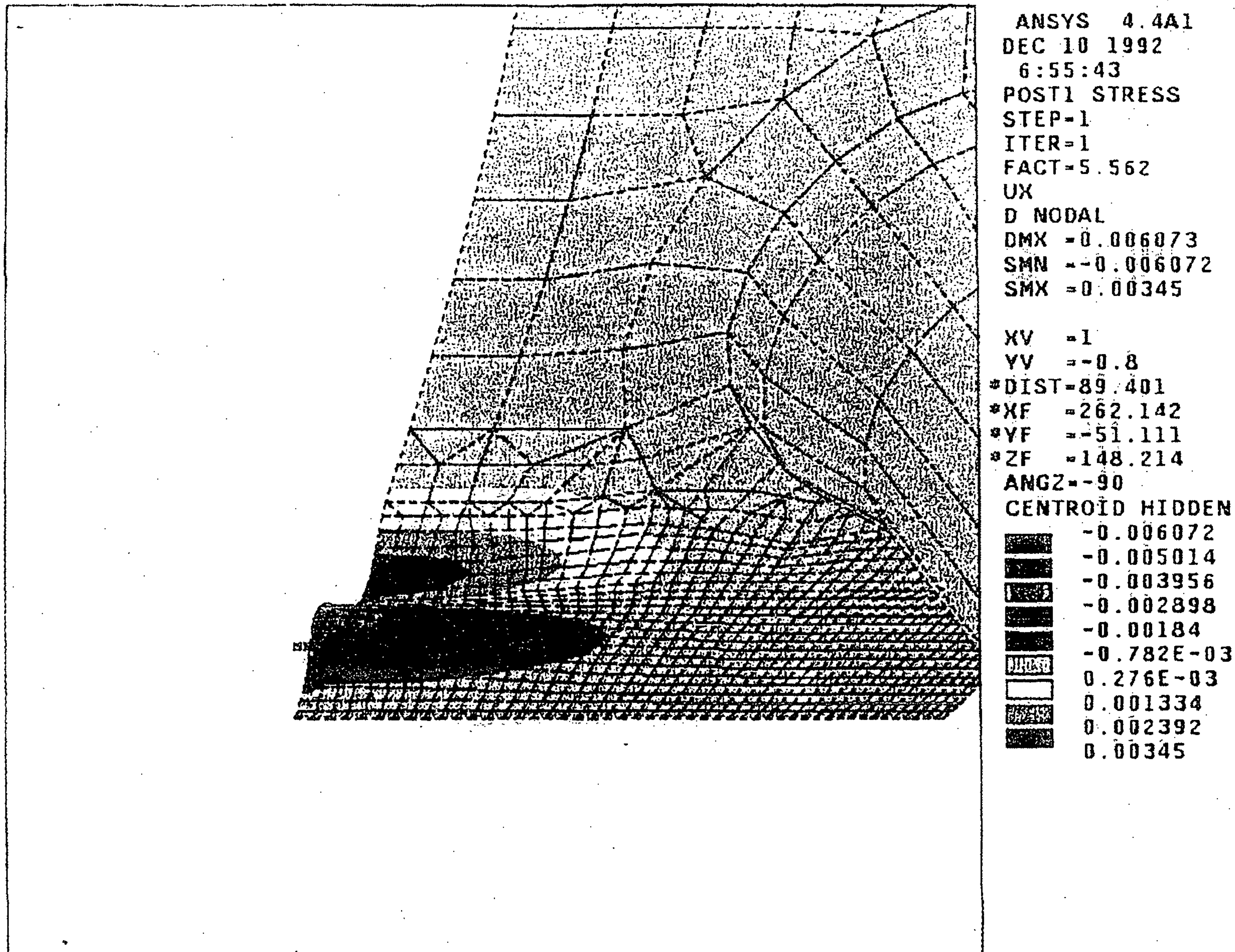
FIGURE 6




OYSTER CREEK DRYWELL ANALYSIS - OCRF05BSS (NO SAND, REFUELING)

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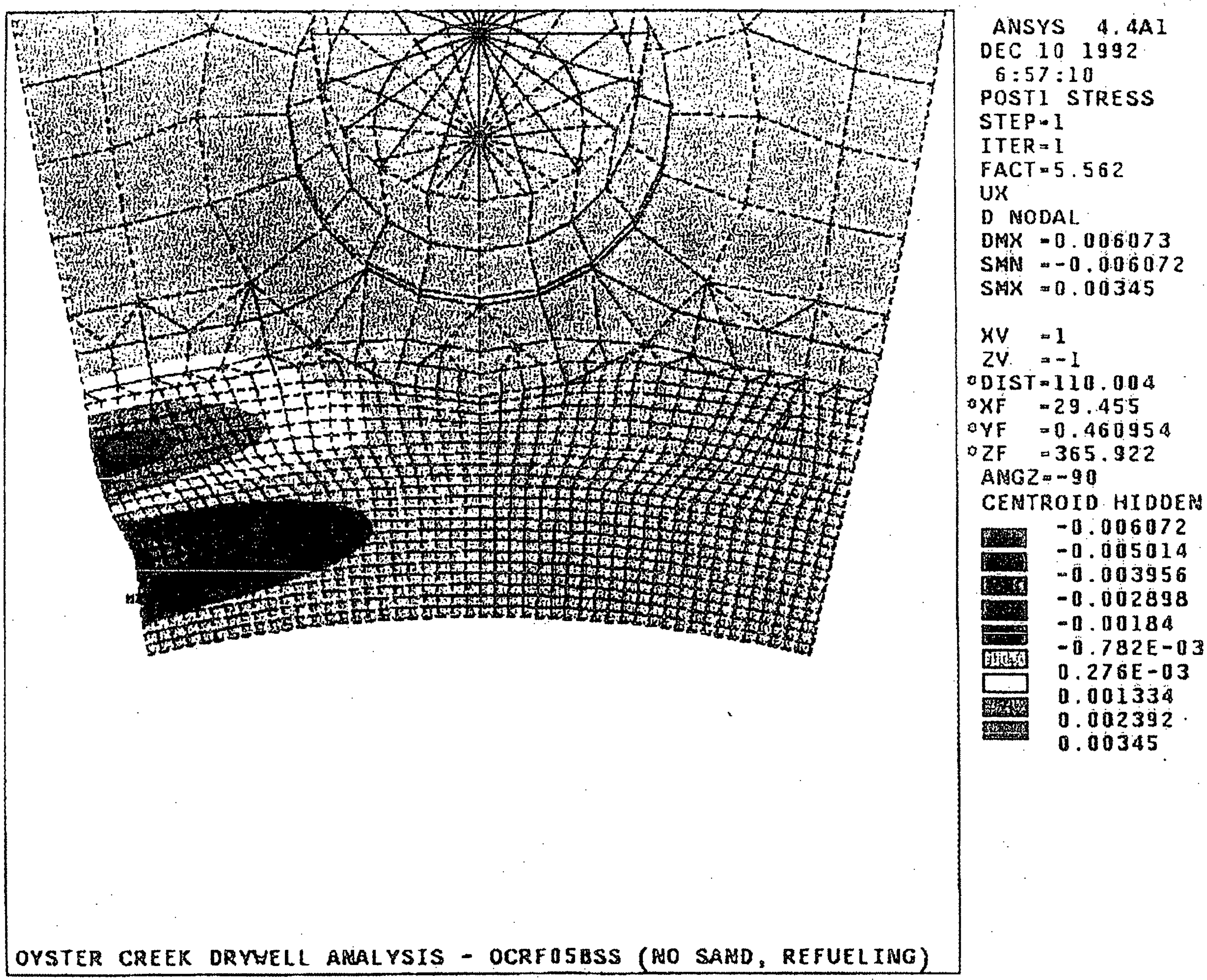


FIGURE 7

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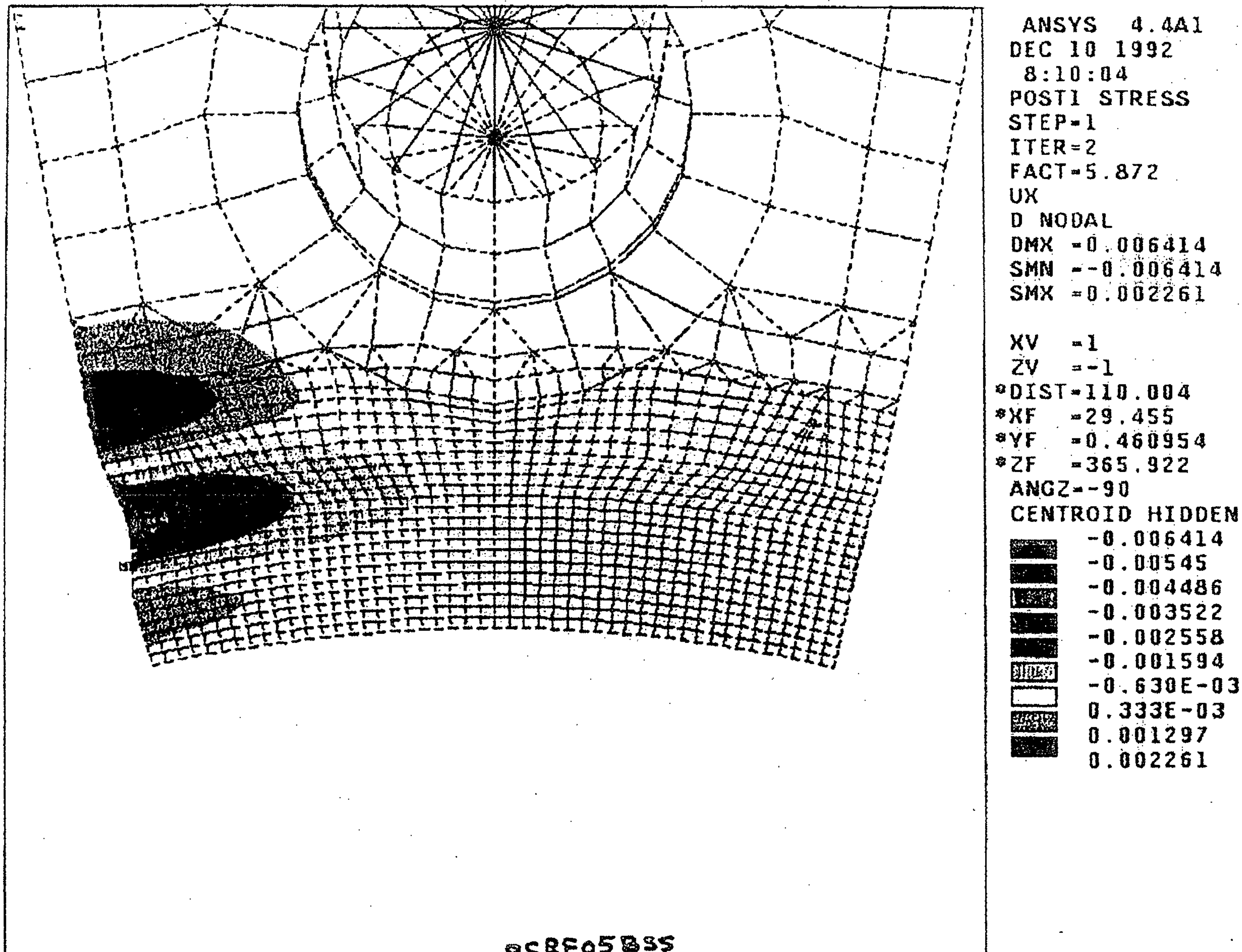
FIGURE 8




ocRF05BSS

OYSTER CREEK DRYWELL ANALYSIS - ~~[illegible]~~ (NO SAND, REFUELING)

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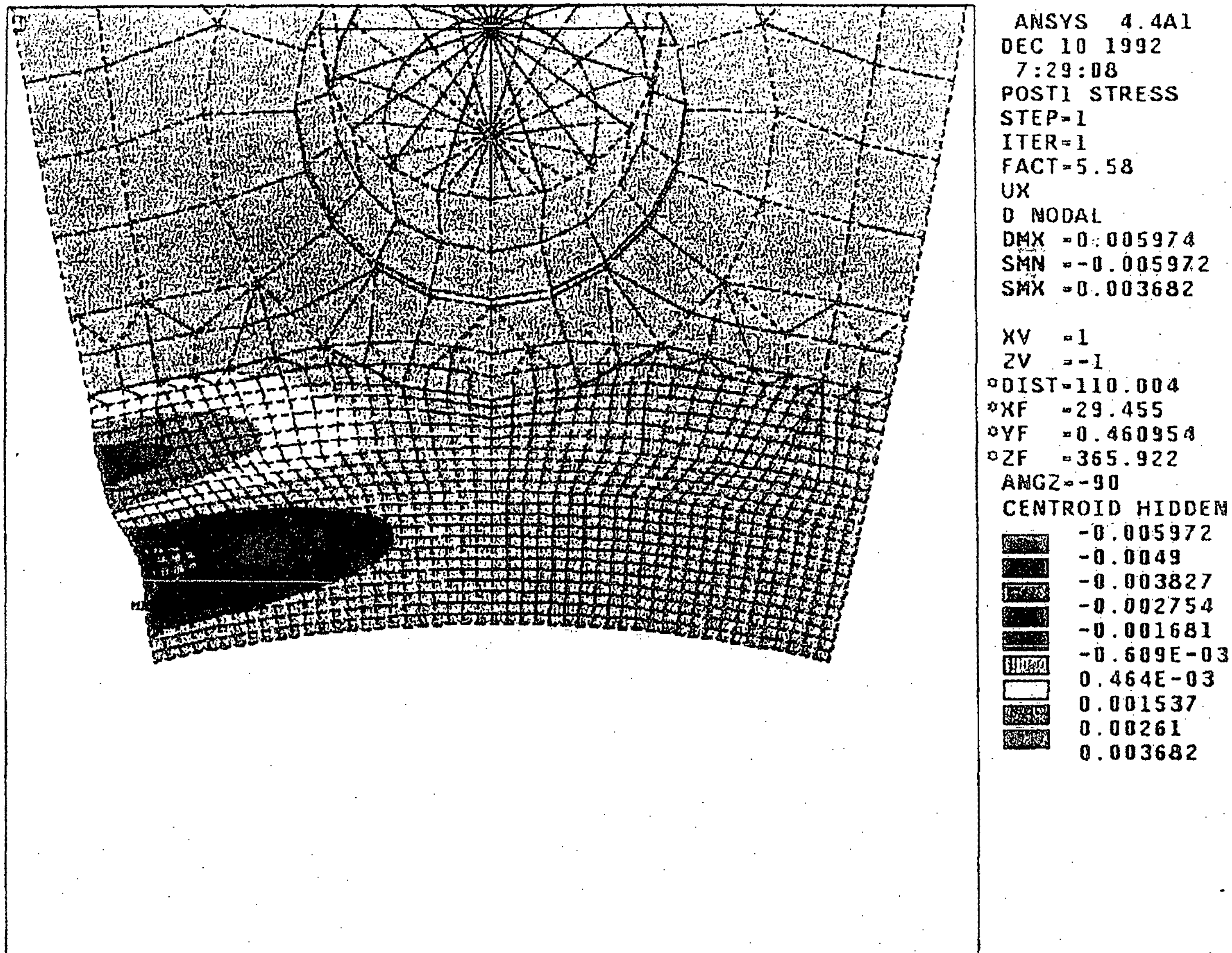
FIGURE 9




OYSTER CREEK DW ANALYSIS - OCRF05AS (NO SAND, REFUELING)

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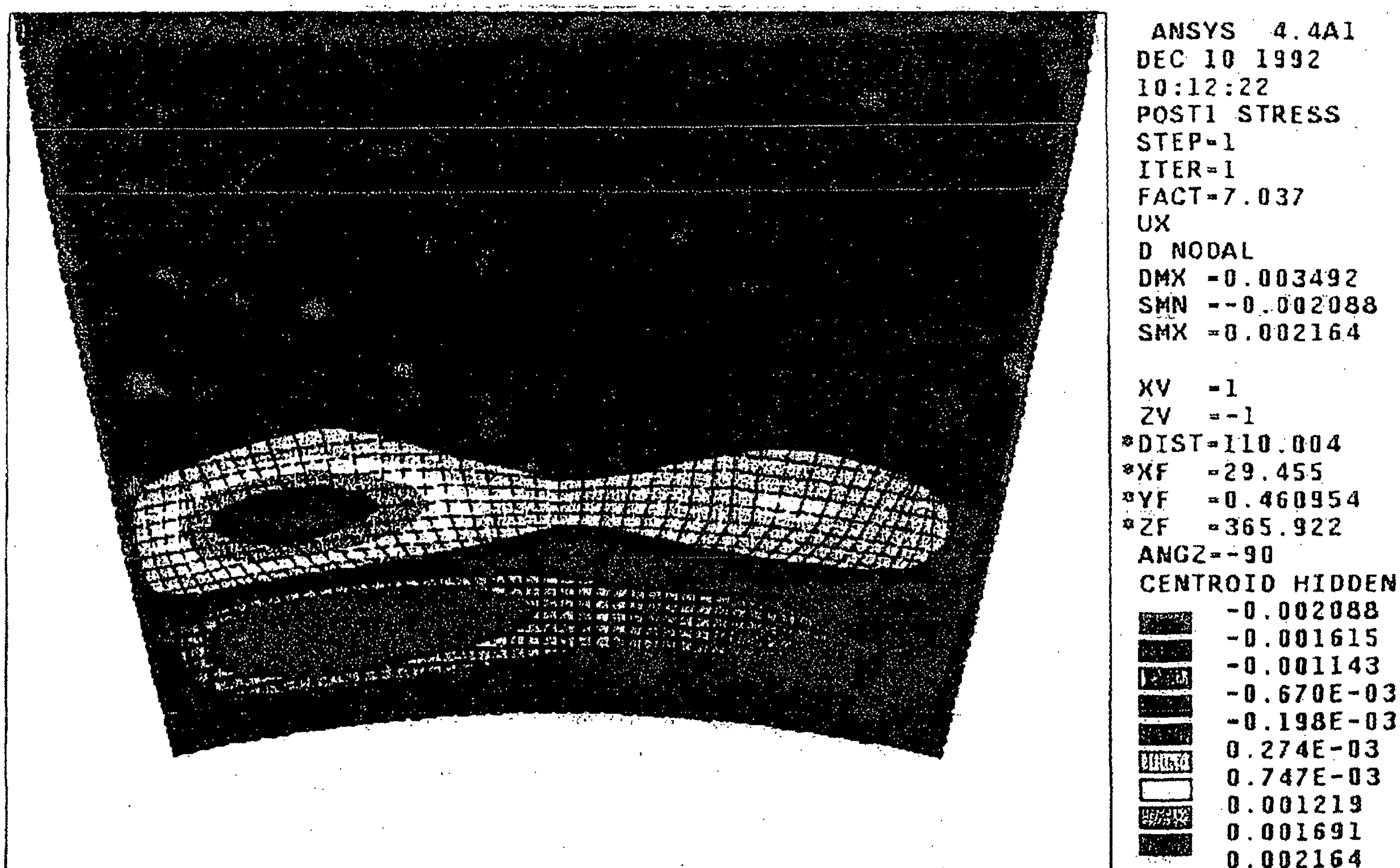
FIGURE 10




OYSTER CREEK DW ANALYSIS - OCRF05AA (NO SAND, REFUELING)

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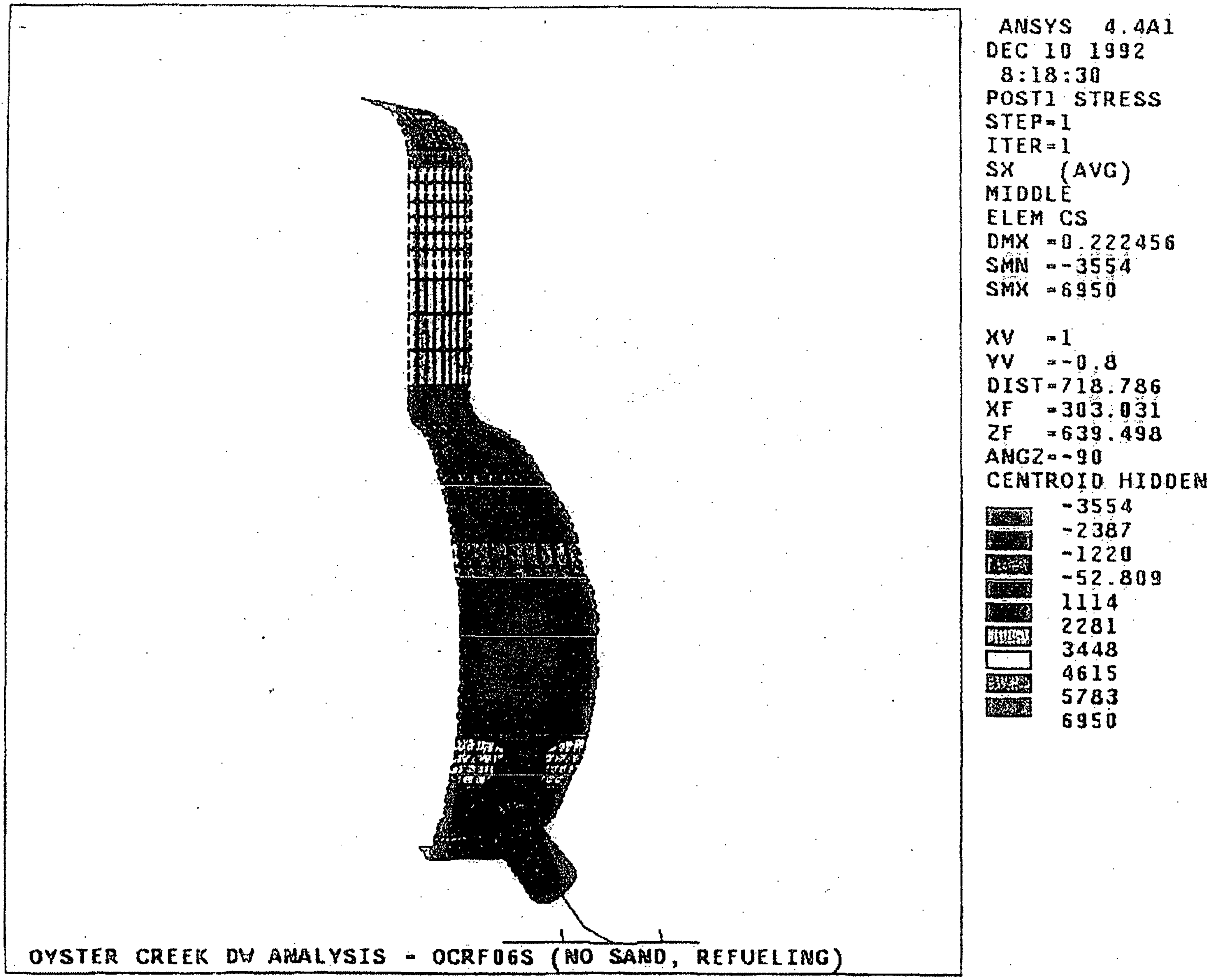
FIGURE 11

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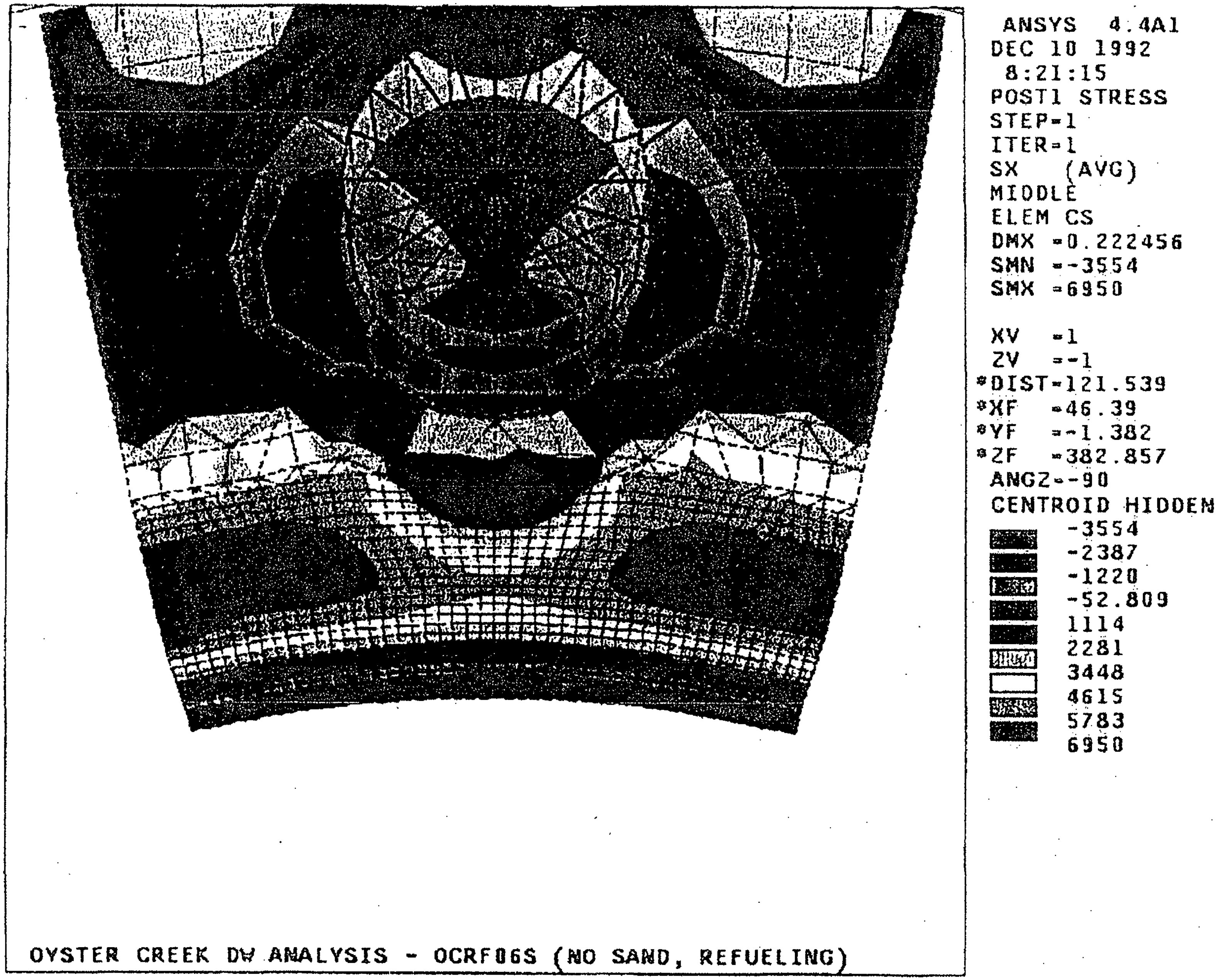
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ZV =-1
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*XF =46.39
*YF =-1.382
*ZF =382.857
ANGZ=-90
CENTROID HIDDEN
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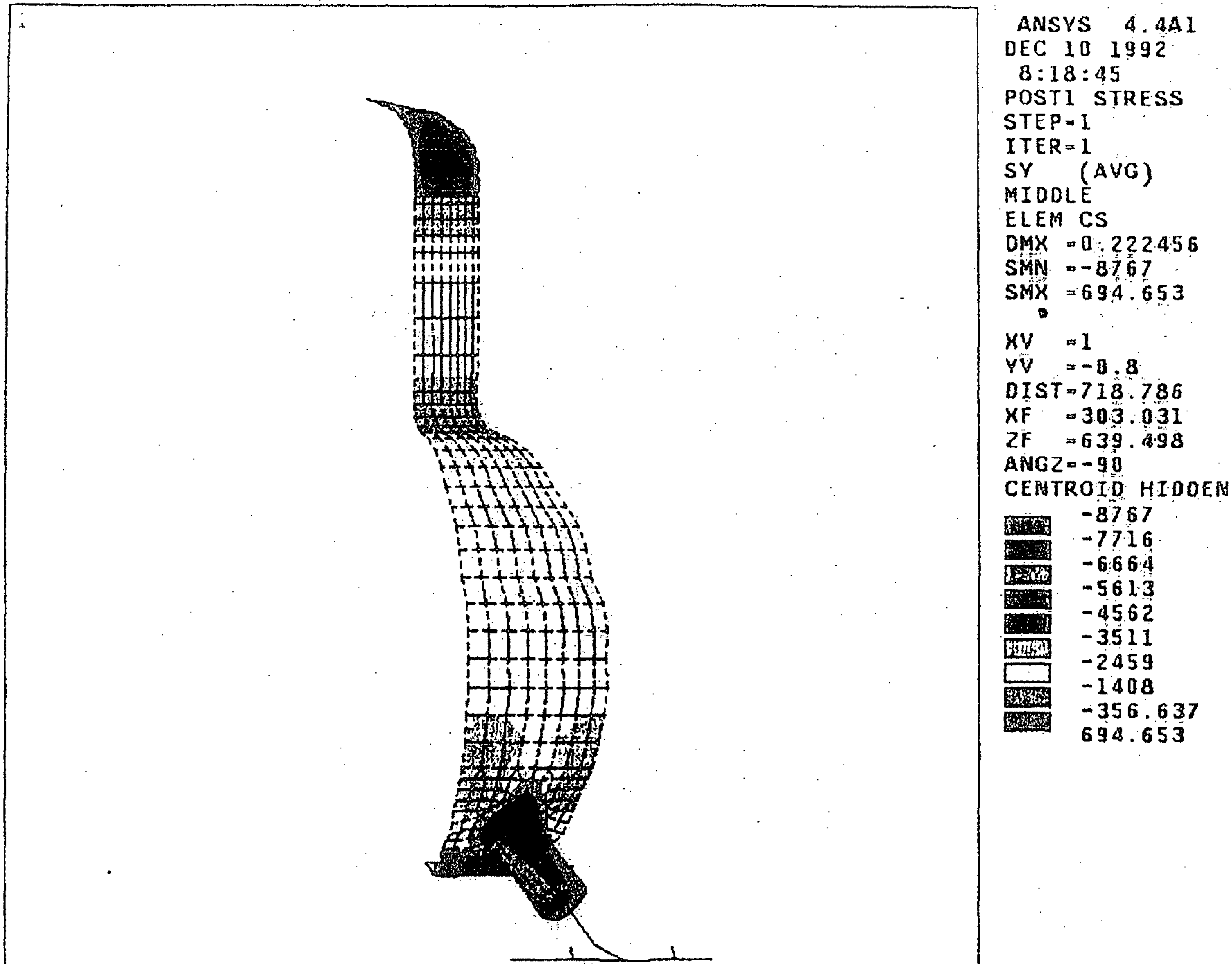
OYSTER CREEK DW ANALYSIS - OCRF06S (NO SAND, REFUELING)

FIGURE 12

FIGURE 13




OYSTER CREEK DW ANALYSIS - OCRF06S (NO SAND, REFUELING)

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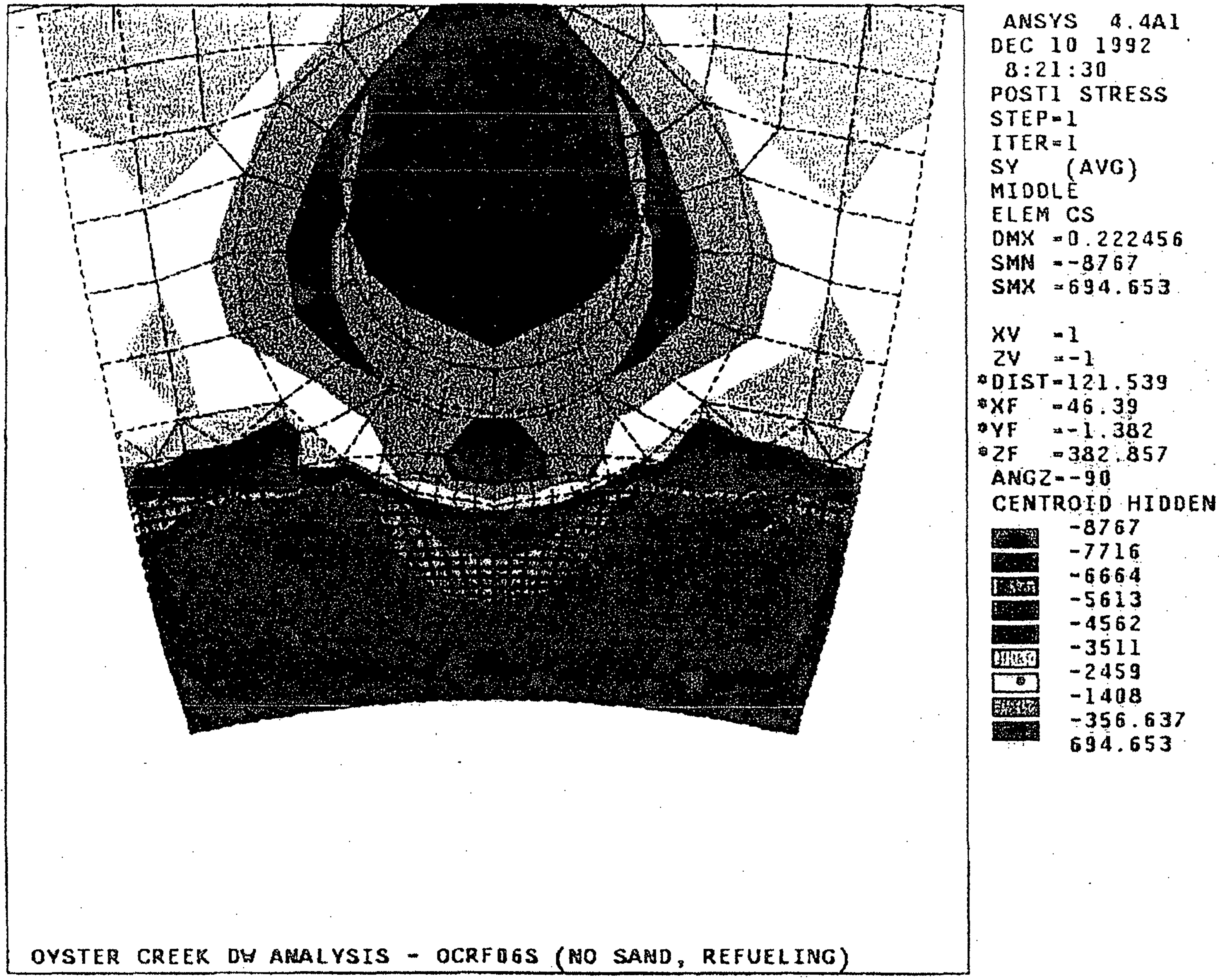
FIGURE 14

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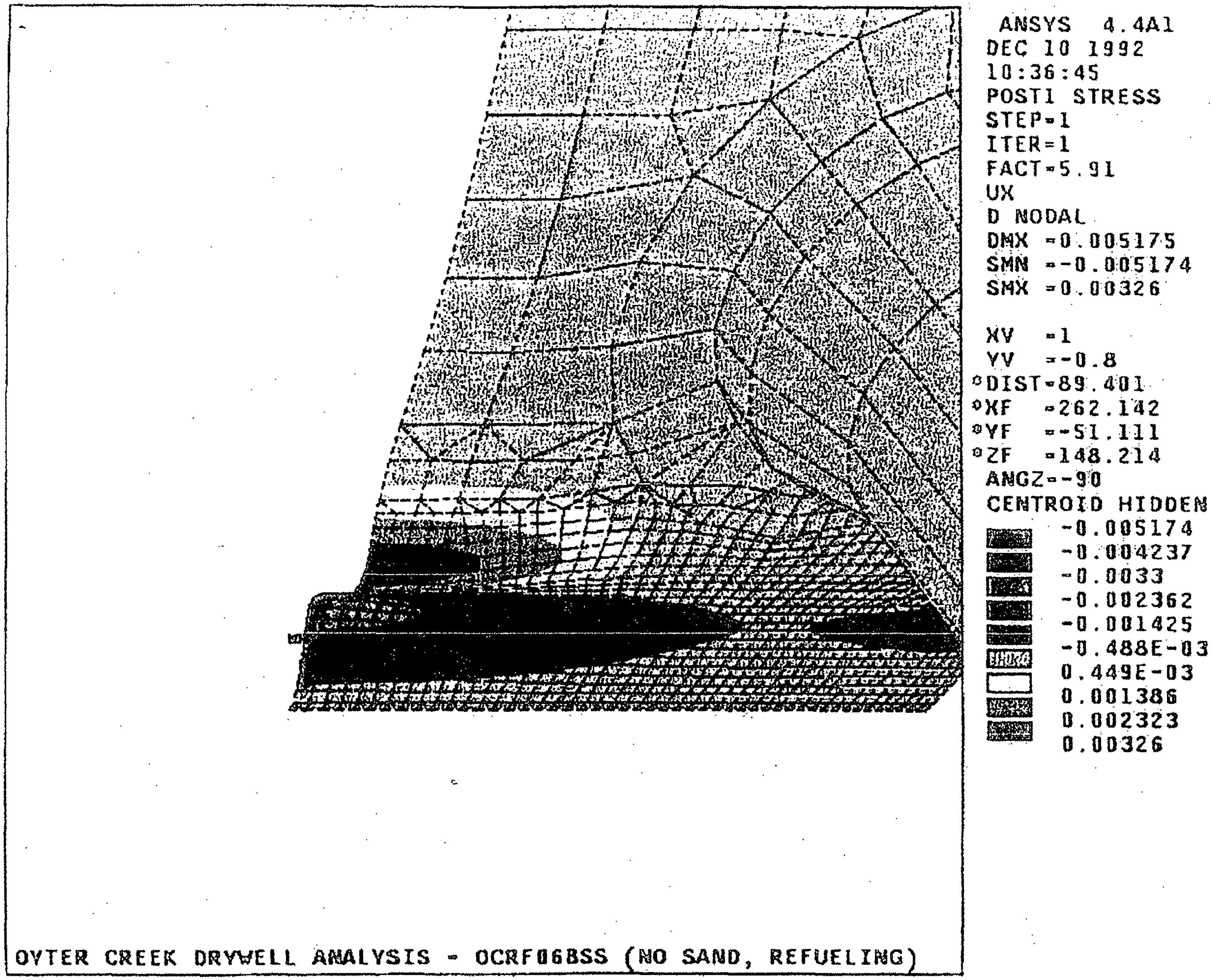
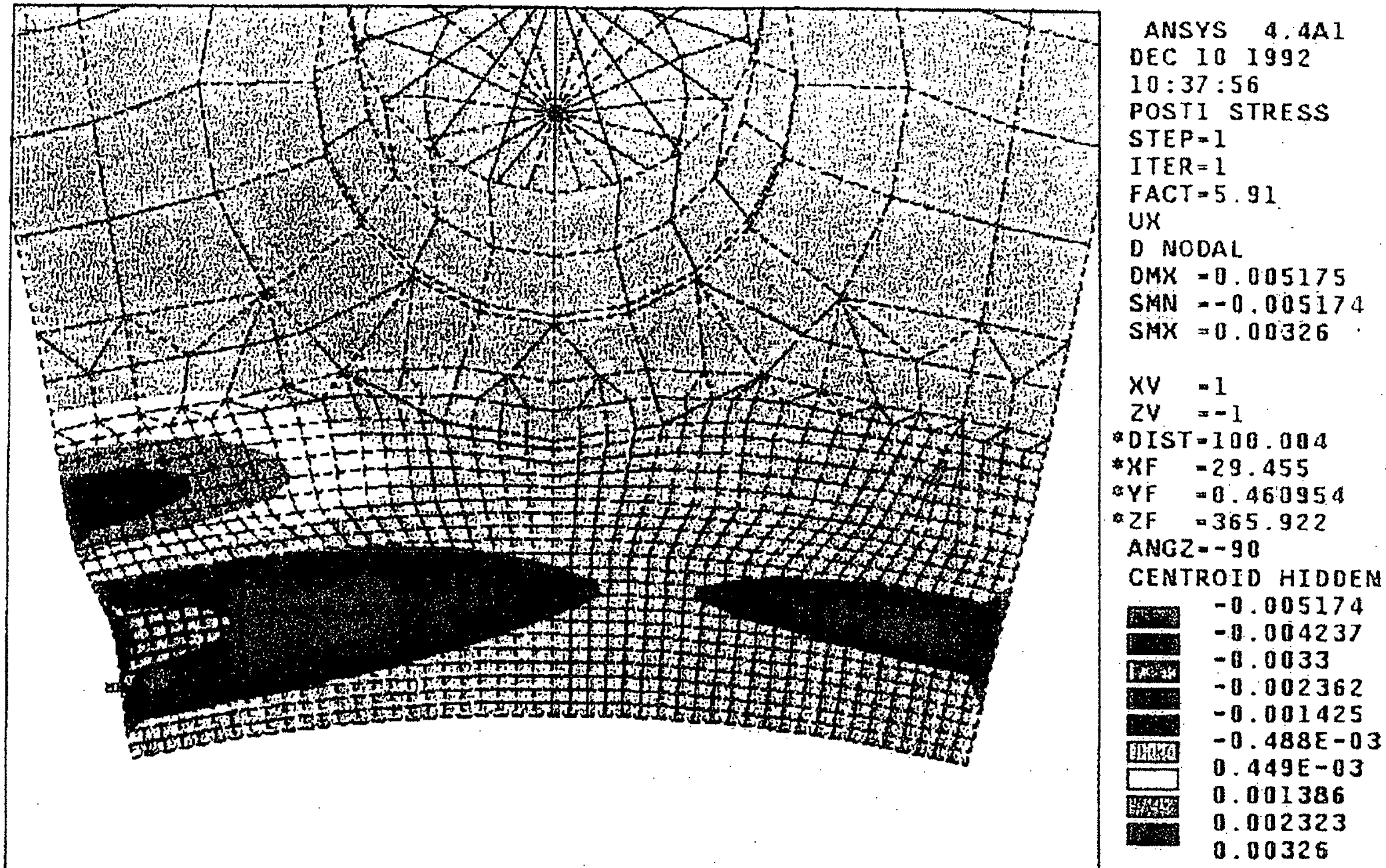
990-2174

FIGURE 15




990-2774

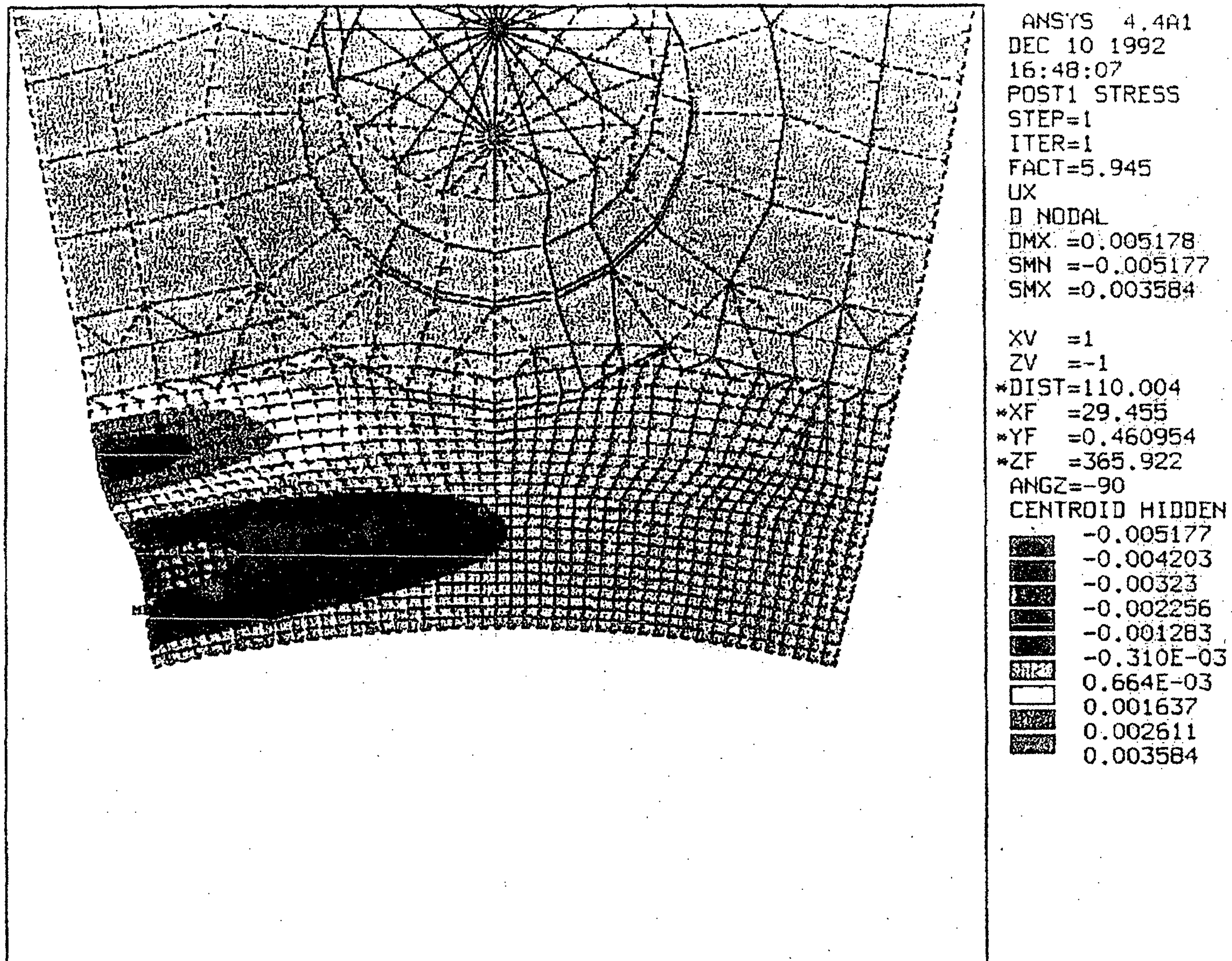
FIGURE 16




OYTER CREEK DRYWELL ANALYSIS - OCRF06BSS (NO SAND, REFUELING)

950-2174

FIGURE 17




OYSTER CREEK DW ANALYSIS - OCRF06AS (NO SAND, REFUELING)

90-2174

990 - 2174

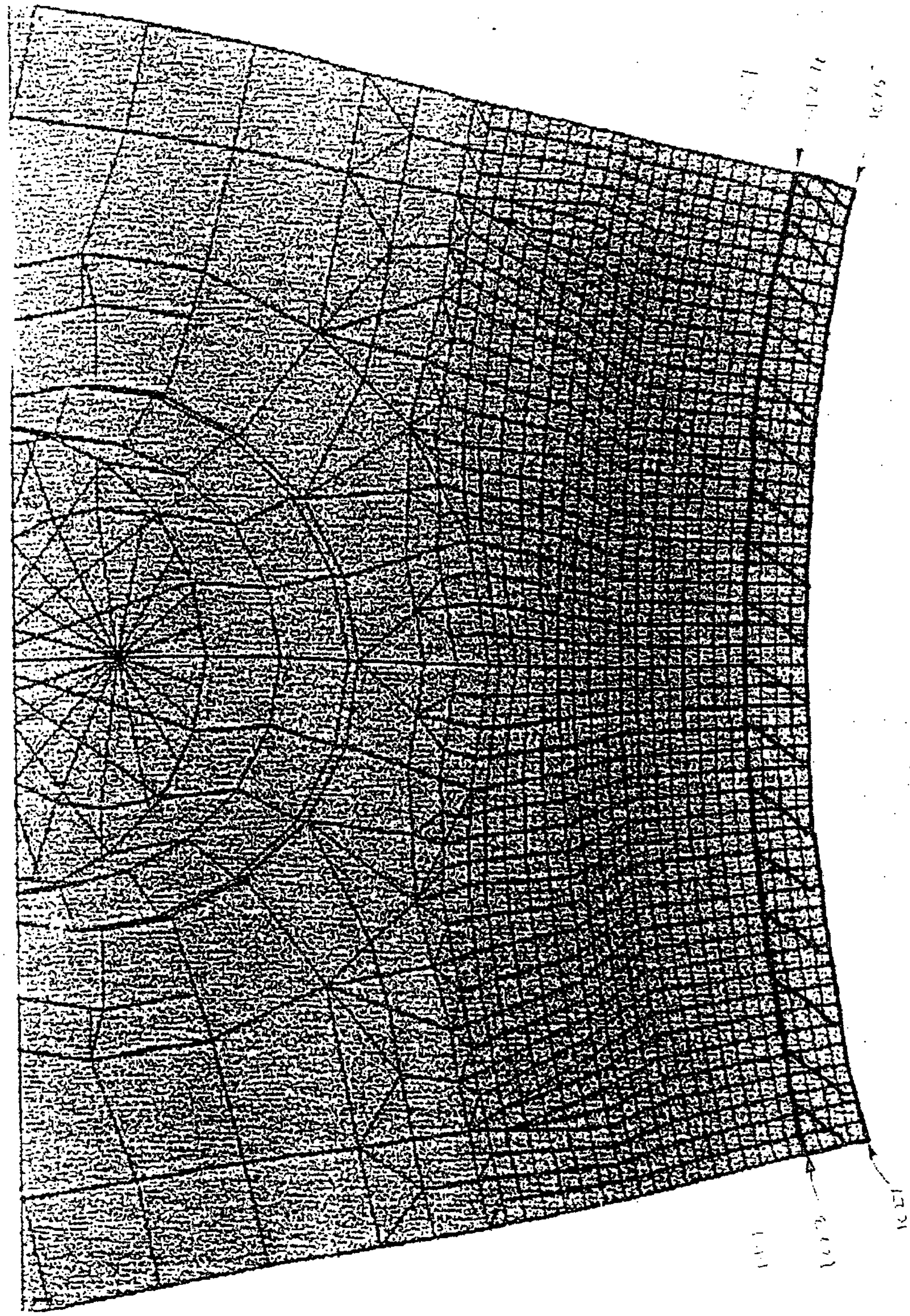
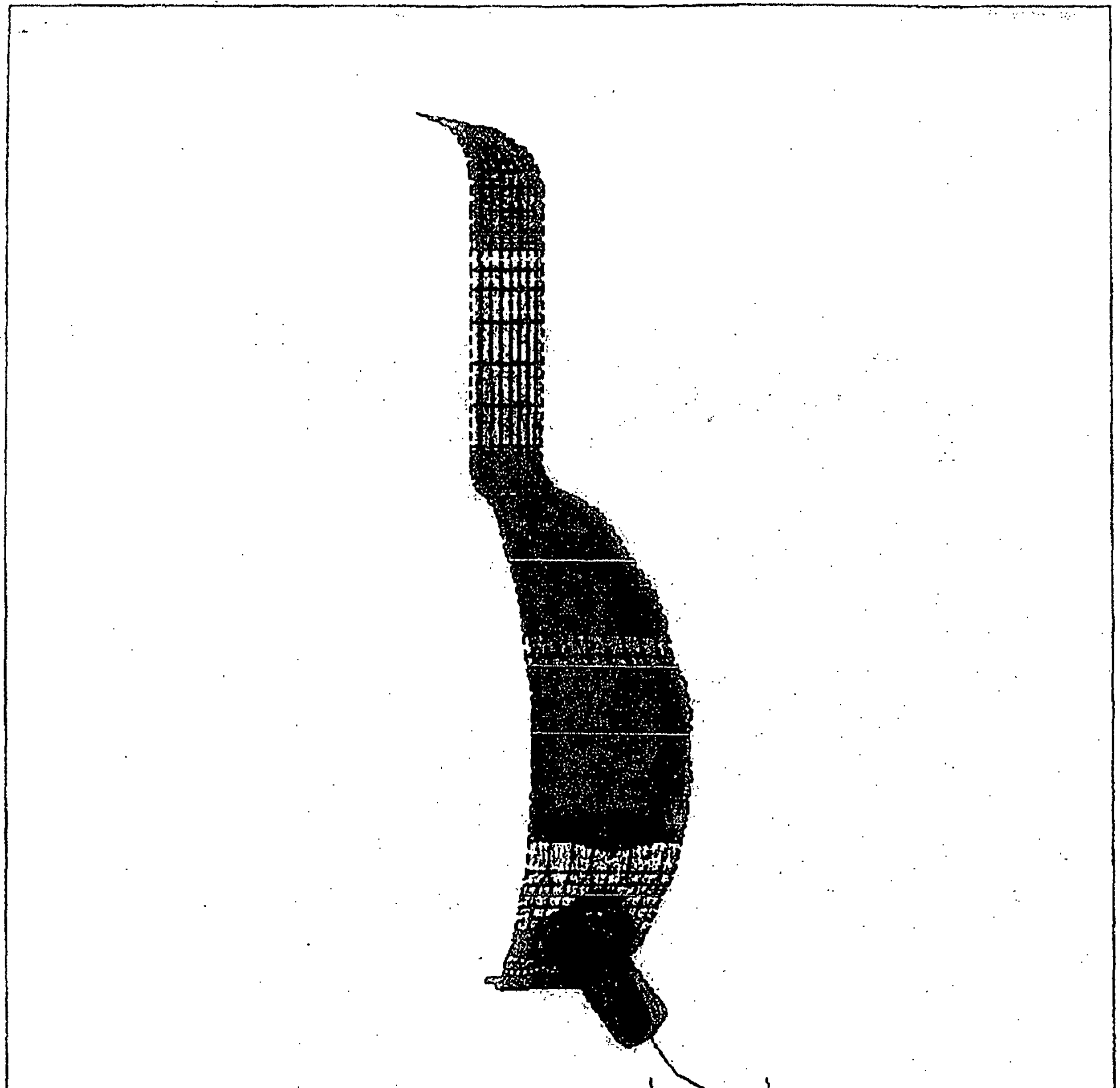


FIGURE 18

FIGURE 19



OYSTER CREEK DRYWELL ANALYSIS - OYCRIS (NO SAND, REFUELING)

ANSYS 4.4A1
DEC 7 1992
12:44:31
POST1 STRESS
STEP=1
ITER=1
SX (AVG)
MIDDLE
ELEM CS
DMX =0.211959
SMN =-3547
SMX =6041

XV =1
YV =-0.8
DIST=718.786
XF =303.031
ZF =639.498
ANGZ=-90
CENTROID HIDDEN
-3547
-2482
-1416
-350.884
714.437
1780
2845
3910
4976
6041

990-2174

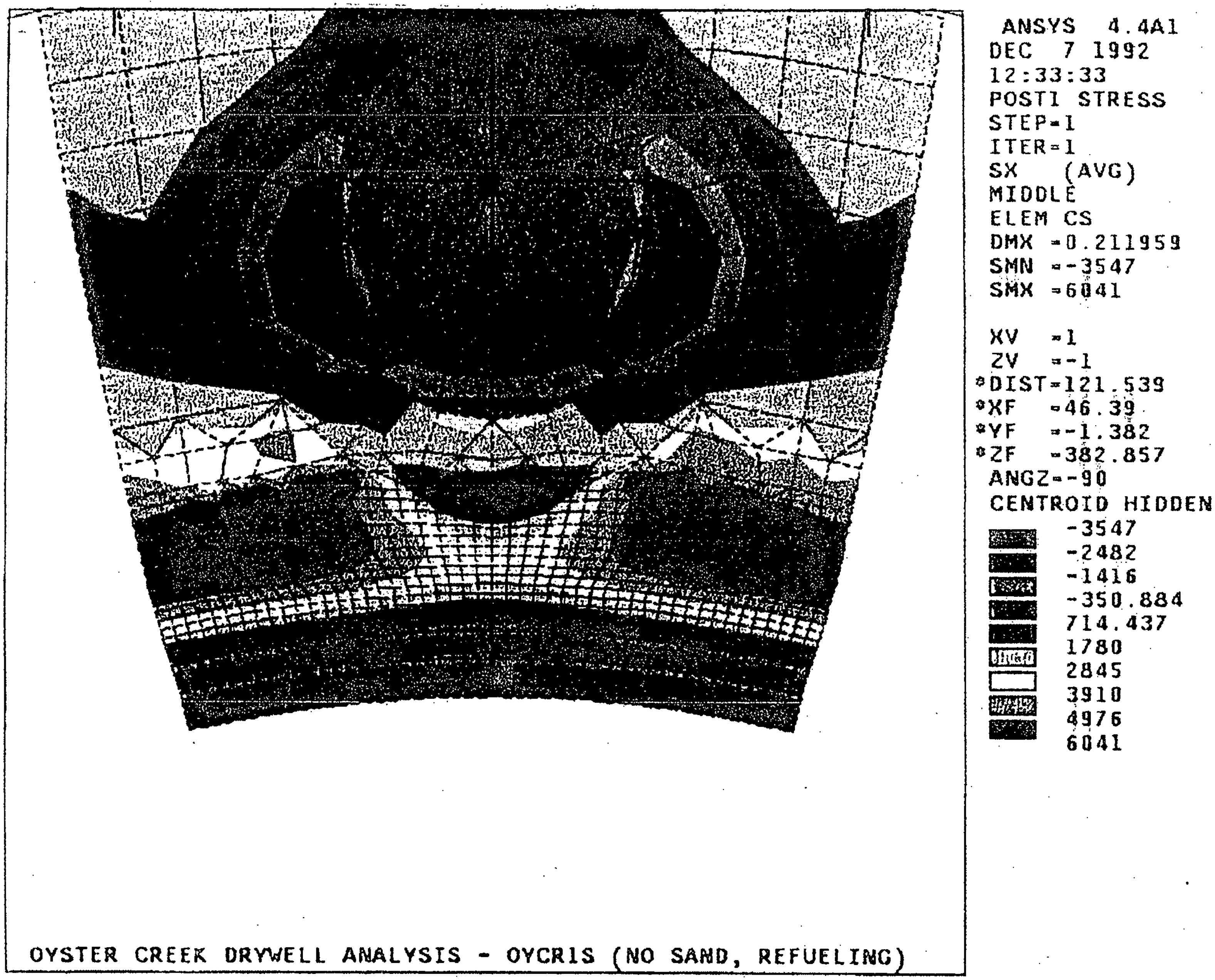
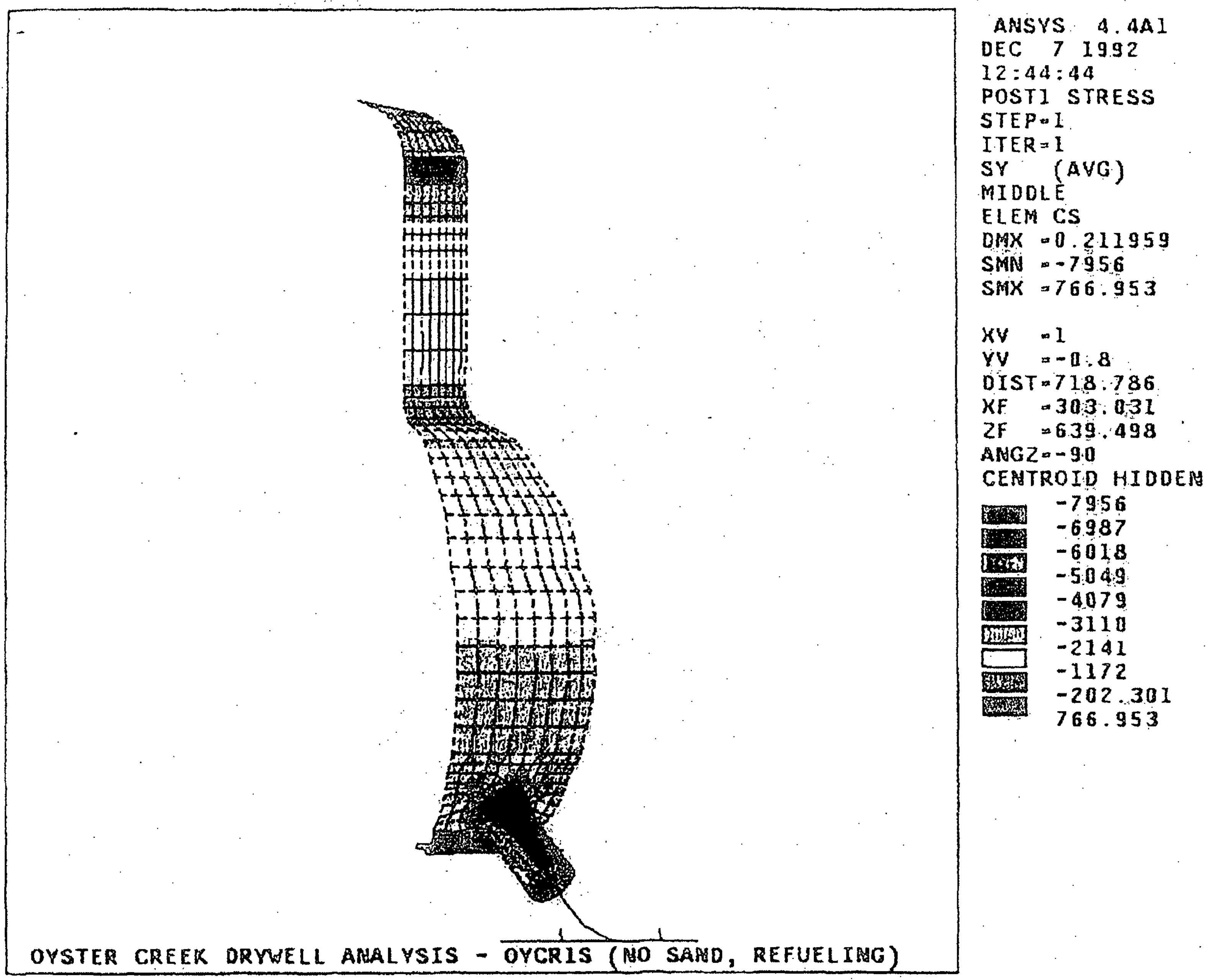



FIGURE 20

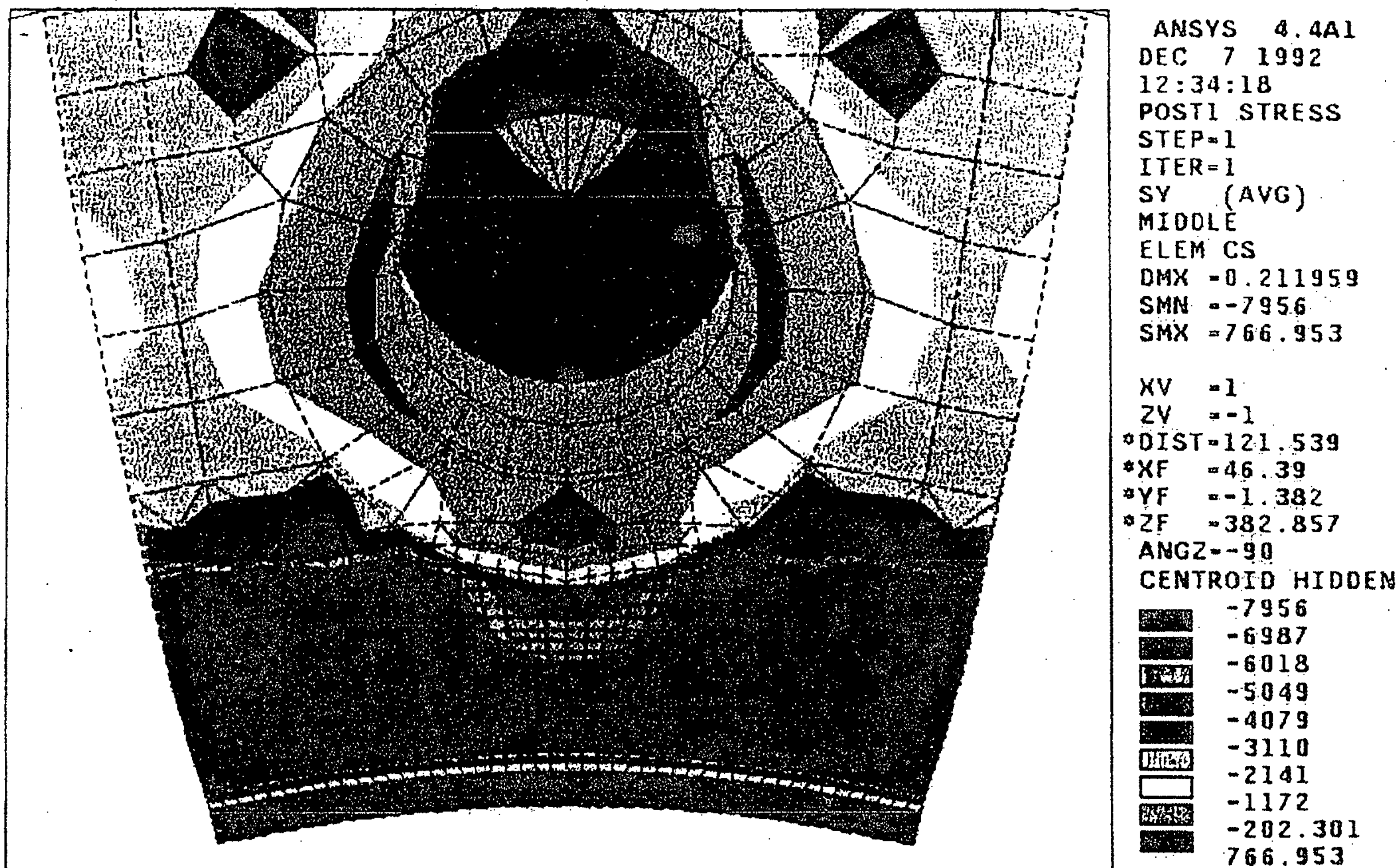
990-2174

FIGURE 21




990-2174

FIGURE 22




OYSTER CREEK DRYWELL ANALYSIS - OYCRIS (NO SAND, REFUELING)

996-2174

APPLIED MERIDIONAL AND CIRCUMFERENTIAL STRESSES - REFUELING CONDITION
ONE FOOT INCREASE IN FIXITY CASE; STRESS RUN: OCRFRLSB.OUT

AVERAGE APPLIED MERIDIONAL STRESS:

The average meridional stress is defined as the average stress across the elevation including nodes 1419 through 1467. Stresses at nodes 1419 and 1467 are weighted only one half as much as the other nodes because they lie on the edge of the modeled 1/10th section of the drywell and thus represent only 1/2 of the area represented by the other nodes.

| Nodes | # of Nodes | Meridional Stress (ksi) | # of Nodes x Meridional Stress (ksi) |
|---|---|---|---|
| 1419-1467 | 1 | -7.726 | -7.726 |
| 1423-1463 | 2 | -7.738 | -15.476 |
| 1427-1459 | 2 | -7.760 | -15.520 |
| 1431-1455 | 2 | -7.682 | -15.364 |
| 1435-1451 | 2 | -7.394 | -14.788 |
| 1439-1447 | 2 | -7.014 | -14.028 |
| 1443 | 1 | -6.834 | -6.834 |
| Total: | 12 | | -89.736 |
| | | | 12 |
| Average Meridional Stress: | | | -7.478 (ksi) |

AVERAGE APPLIED CIRCUMFERENTIAL STRESS:

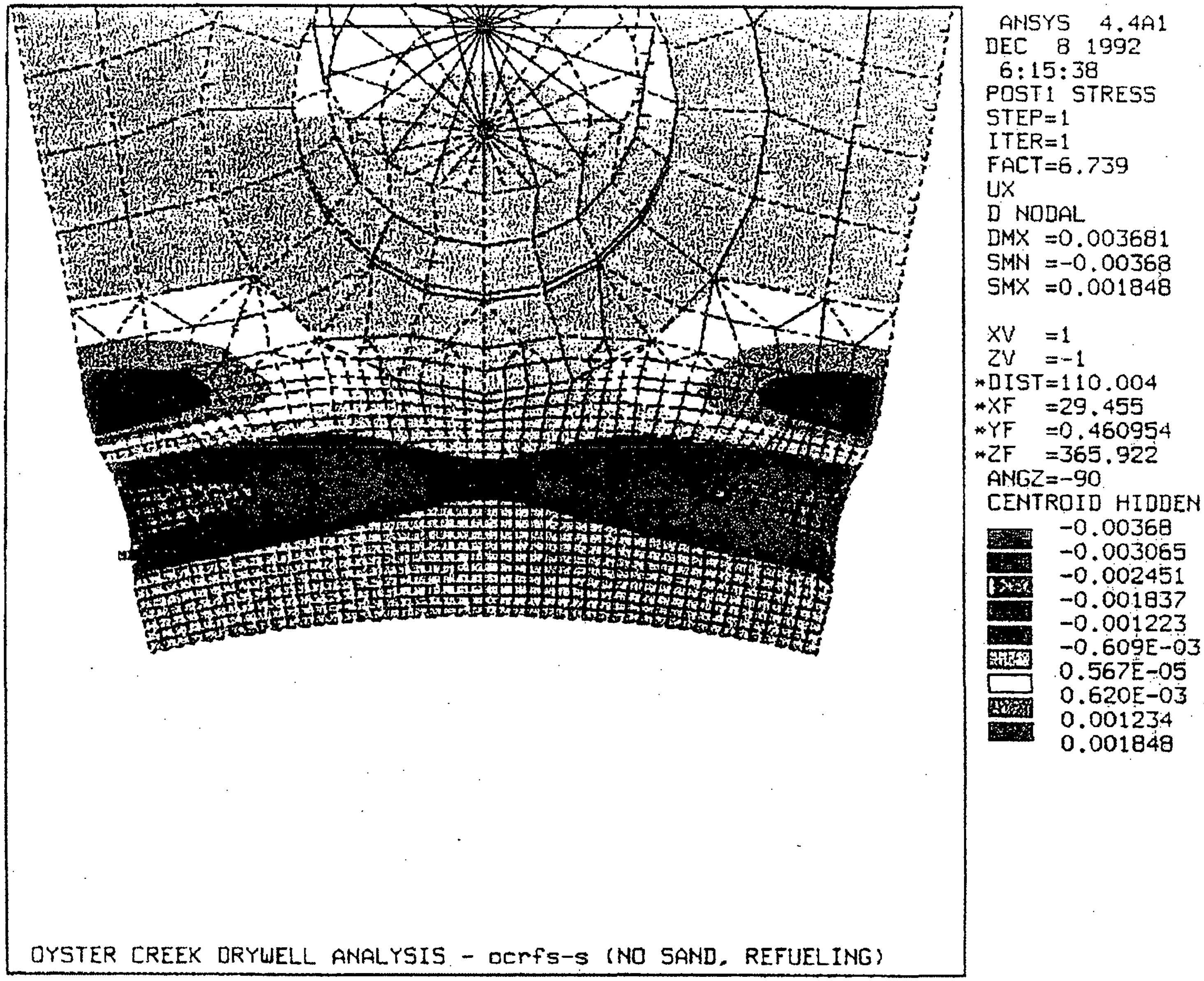
The circumferential stress is averaged along the vertical line from node 1223 to node 2058.

| Nodes | # of Nodes | Circumferential Stress (ksi) | # of Nodes x Circumferential Stress (ksi) |
|---|---|---|---|
| 1223 | 0 | -1.175 | 0.000 |
| 1419 | 1 | 0.505 | 0.505 |
| 1615 | 1 | 4.165 | 4.165 |
| 1811 | 1 | 5.846 | 5.846 |
| 2058 | 1 | 5.024 | 5.024 |
| Total: | 4 | | 15.54 |
| | | | 4 |
| Average Circumferential Stress: | | | 3.885 (ksi) |

OCRFST06.WK1

FIGURE 23

FIGURE 24




940-2174

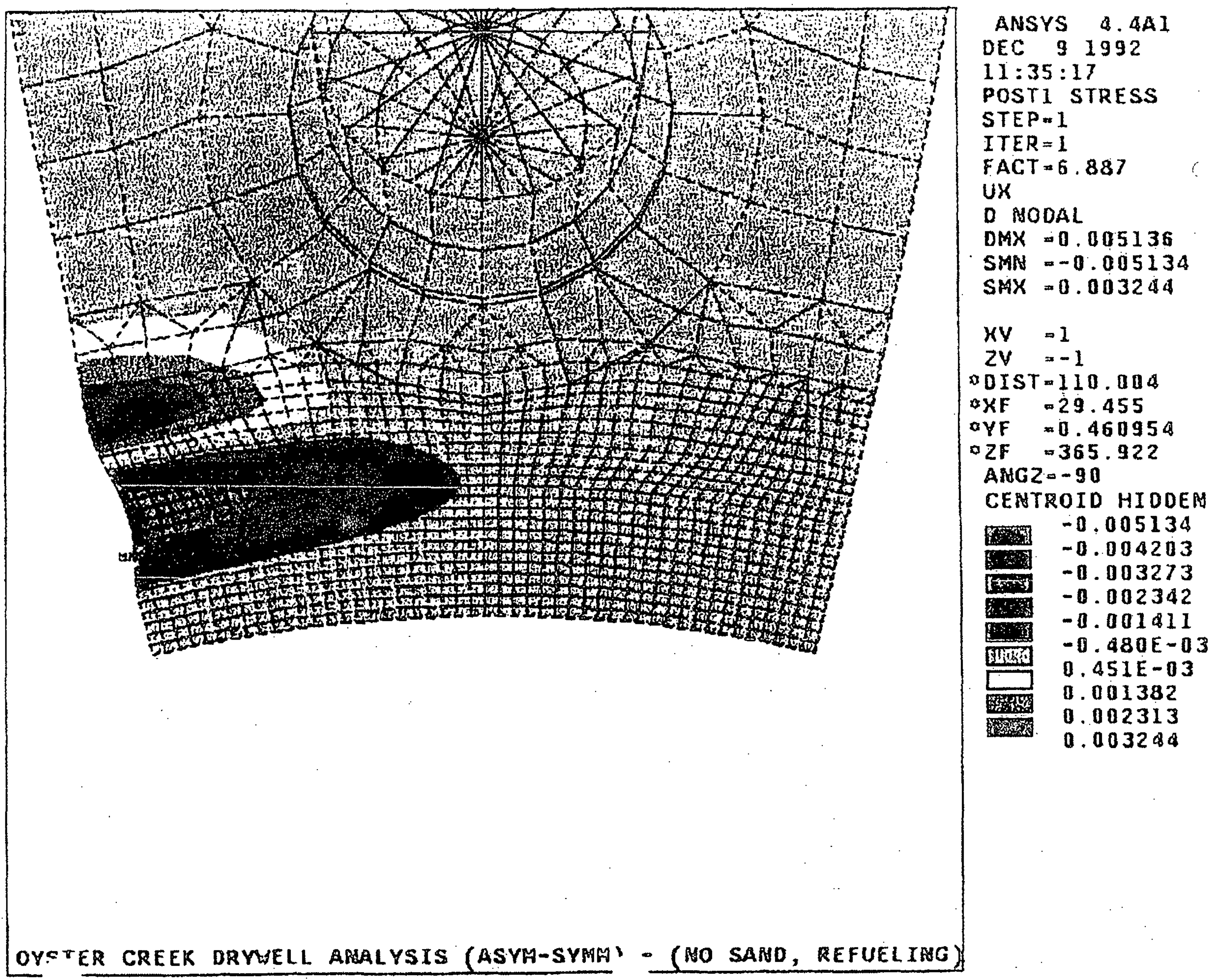



FIGURE 25

990-2174

CALCULATION OF ALLOWABLE BUCKLING STRESSES - REFUELING CASE, NO SAND
ONE FOOT INCREASE IN FIXITY CASE; STRESS RUN OCRFRLSB.OUT,
BUCKLING RUN OYCRSBBK.OUT

| 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 Modulus of Elasticity, E | (ksi) | 29600 | |
| 5 | Factor of Safety, FS | - | 2 | |
| | *** BUCKLING ANALYSIS RESULTS | | | |
| 6 | Theoretical Elastic Instability Stress, Ste | (ksi) | 50.394 | 6.739 |
| | *** STRESS ANALYSIS RESULTS | | | |
| 7 | Applied Meridional Compressive Stress, Sm | (ksi) | 7.478 | |
| 8 | Applied Circumferential Tensile Stress, Sc | (ksi) | 3.885 | |
| | *** CAPACITY REDUCTION FACTOR CALCULATION | | | |
| 9 | Capacity Reduction Factor, ALPHAi | - | 0.207 | |
| 10 | Circumferential Stress Equivalent Pressure, Peq | (psi) | 13.616 | |
| 11 | 'X' Parameter, X= (Peq/4E) (d/t)^2 | - | 0.075 | |
| 12 | Delta C (From Figure - ) | - | 0.064 | |
| 13 | Modified Capacity Reduction Factor, ALPHA,i,mod | - | 0.313 | |
| 14 | Reduced Elastic Instability Stress, Se | (ksi) | 15.753 | 2.107 |
| | *** PLASTICITY REDUCTION FACTOR CALCULATION | | | |
| 15 | Yield Stress Ratio, DELTA=Se/Sy | - | 0.415 | |
| 16 | Plasticity Reduction Factor, NUi | - | 1.000 | |
| 17 | Inelastic Instability Stress, Si = NUi x Se | (ksi) | 15.753 | 2.107 |
| | *** ALLOWABLE COMPRESSIVE STRESS CALCULATION | | | |
| 18 | Allowable Compressive Stress, Sall = Si/FS | (ksi) | 7.877 | 1.053 |
| 19 | Compressive Stress Margin, M=(Sall/Sm -1) x 100% | (%) | 5.3 | |

FIGURE 26

REFNSND2.WK1

03/20/96 16:25:08

APPLICANT'S EXHIBIT 40

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# Oyster Creek License Renewal Presentation to ACRS Subcommittee

## January 18, 2007

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An Exelon Company

# AmerGen Representatives

- Fred Polaski
- John O'Rourke
- Howie Ray
- Pete Tamburro
- Dr. Hardayal Mehta
- Barry Gordon
- Jon Cavallo
- Ahmed Ouaou

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# Agenda

- Drywell Shell Corrosion
  - Physical Overview
  - Cause and Corrective Actions
  - Drywell Shell Thickness Analysis
  - Sand Bed Region
  - Embedded Portions of the Drywell Shell
  - Upper Shell

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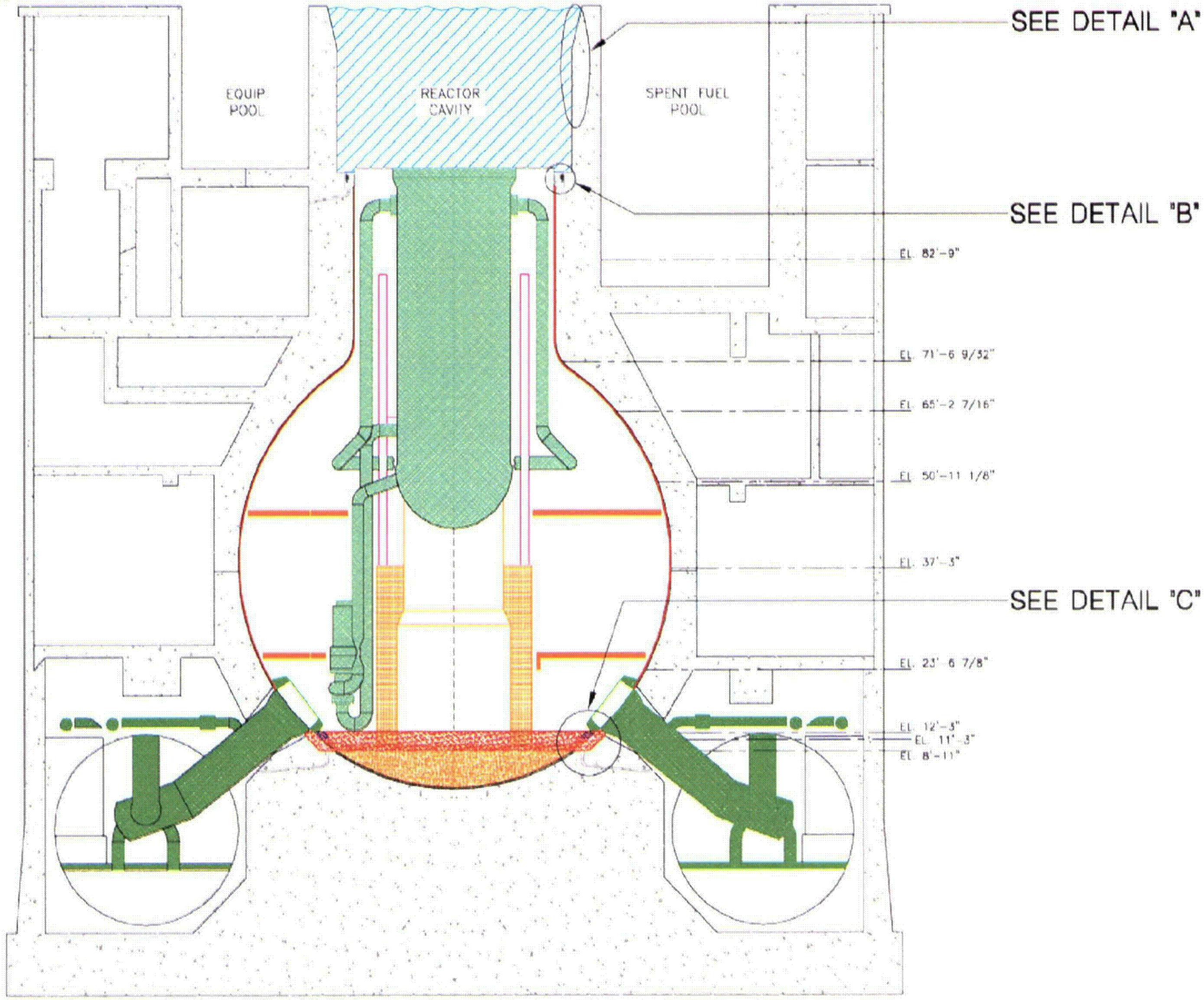
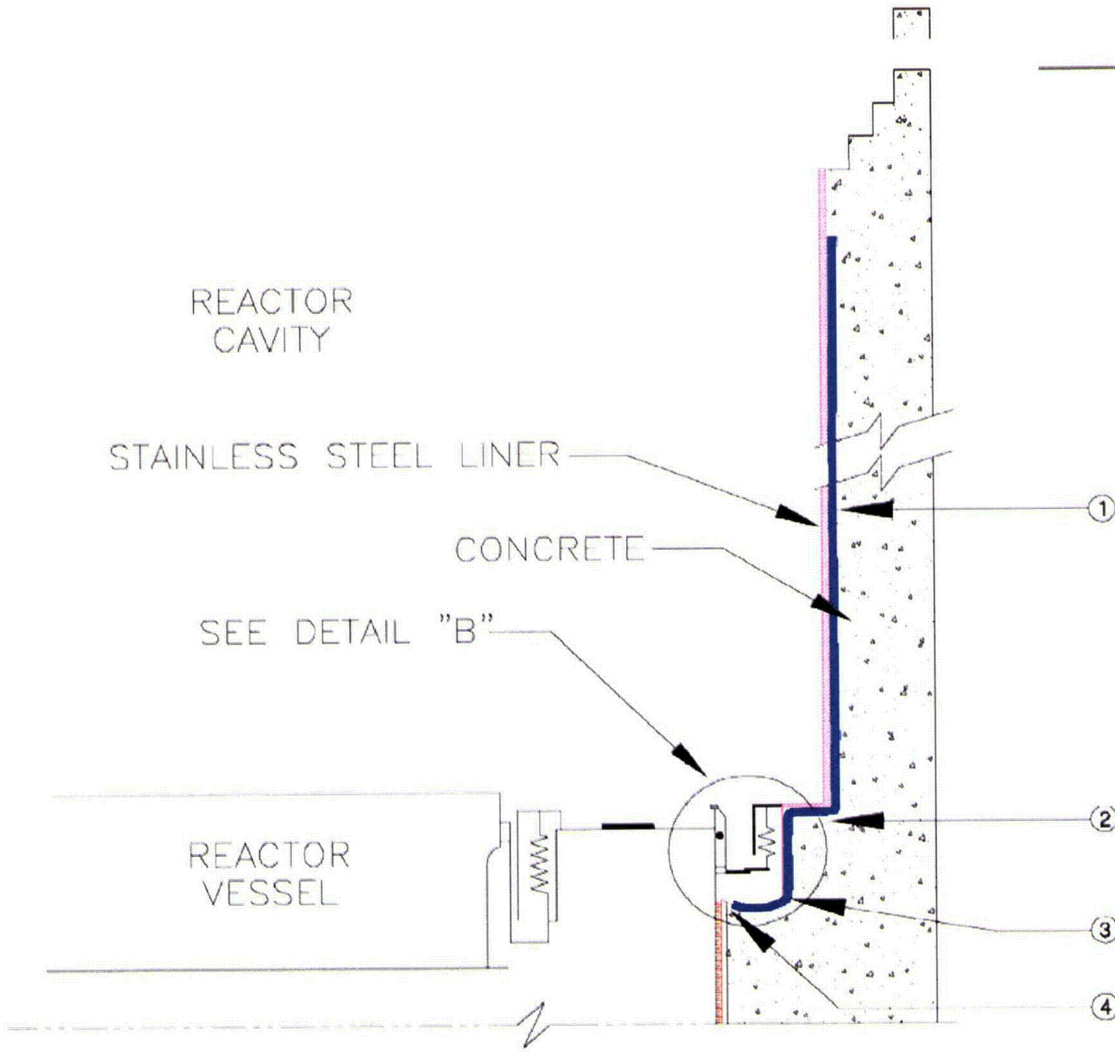
# Drywell Shell Corrosion Cause and Corrective Actions


SEE DETAIL "A"
SEE DETAIL "B"
SEE DETAIL "C"
EQUIP POOL
REACTOR CAVITY
SPENT FUEL POOL
EL. 82'-9"
EL. 71'-6 9/32"
EL. 65'-2 7/16"
EL. 50'-11 1/8"
EL. 37'-3"
EL. 23'-6 7/8"
EL. 12'-3"
EL. 11'-3"
EL. 8'-11"




DRYWELL AND REACTOR CAVITY SECTION
DETAIL "A"

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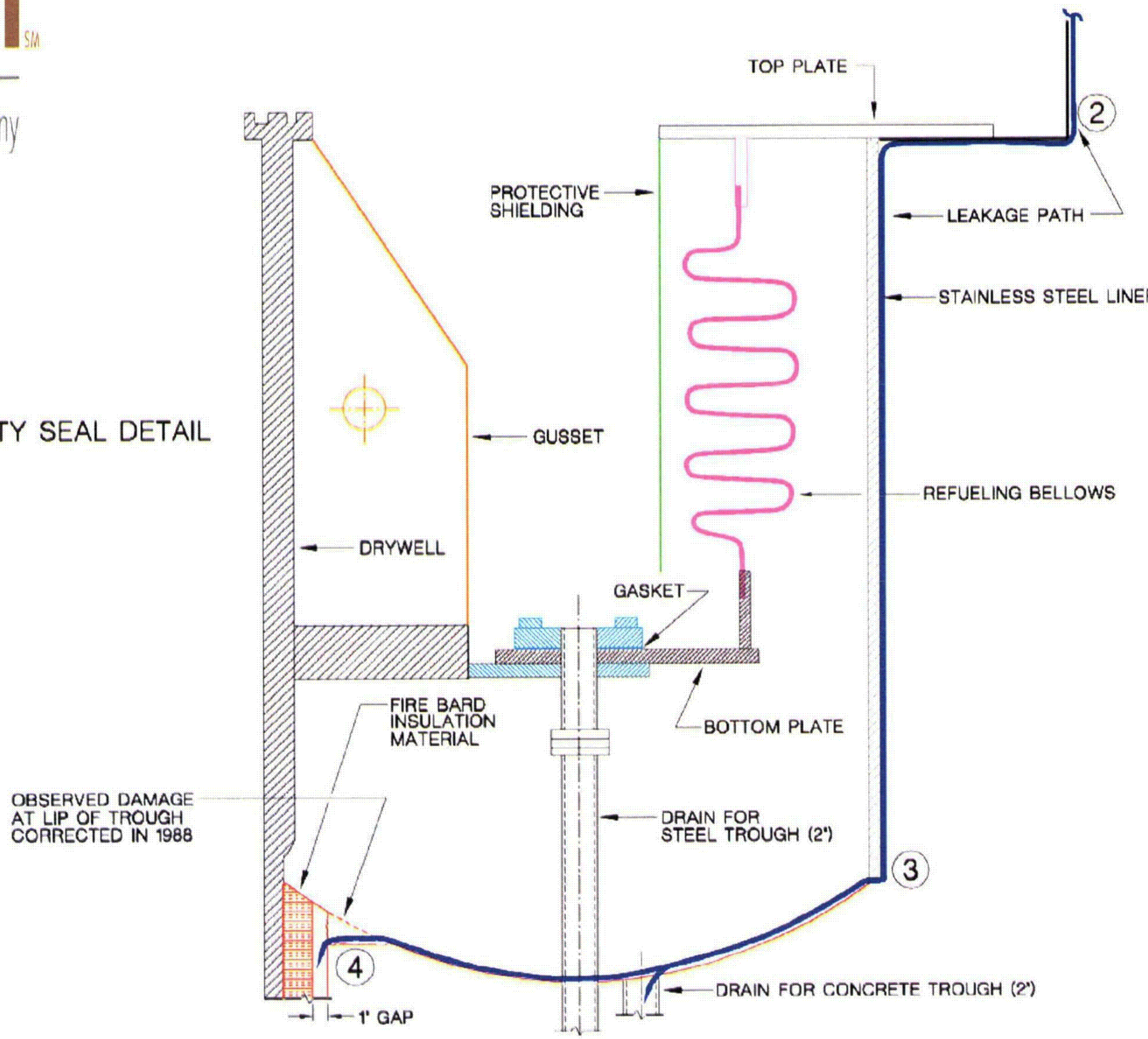
DRYWELL TO REACTOR CAVITY SEAL DETAIL
DETAIL "B"



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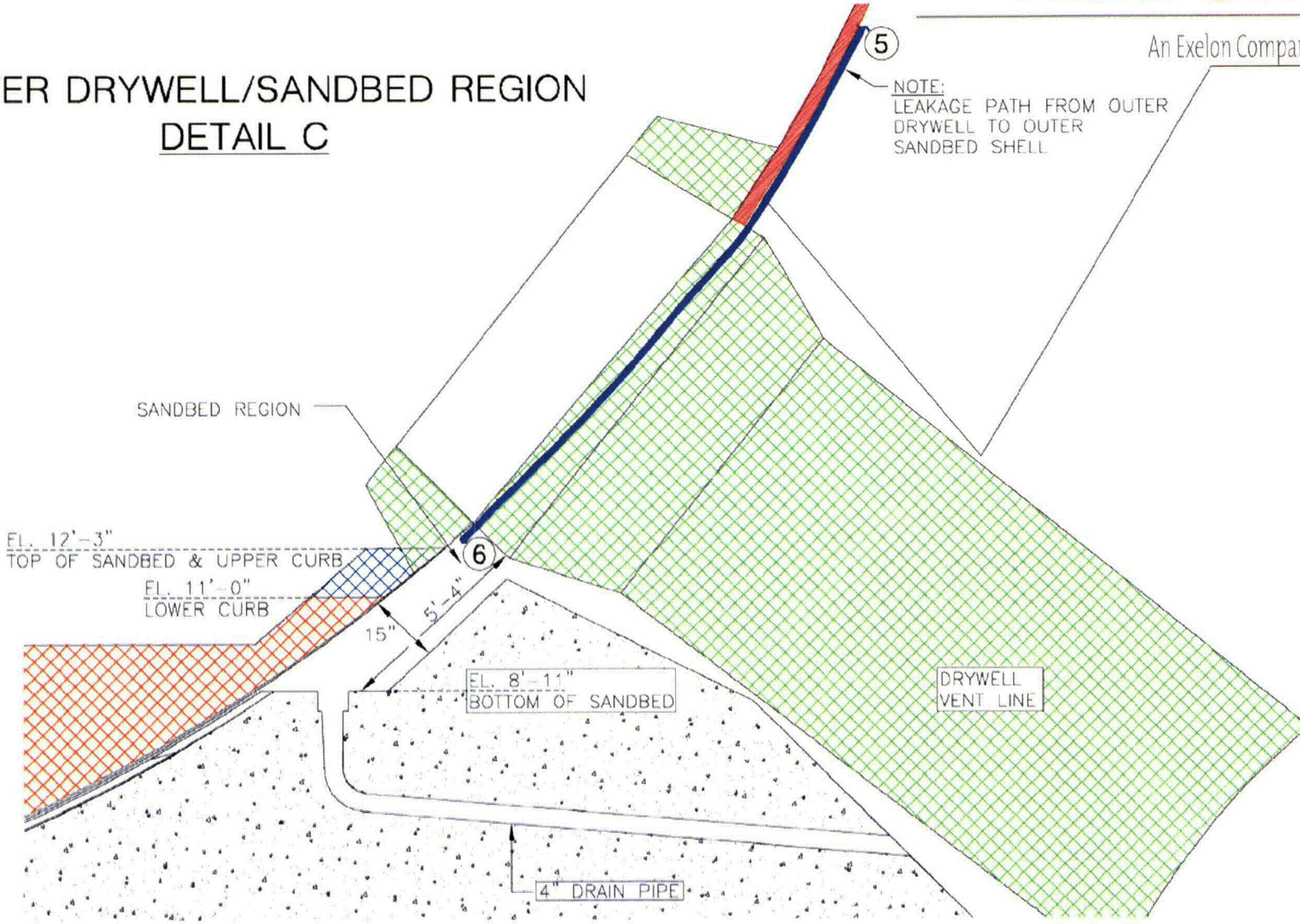
# LOWER DRYWELL/SANDBED REGION
## DETAIL C



# REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE

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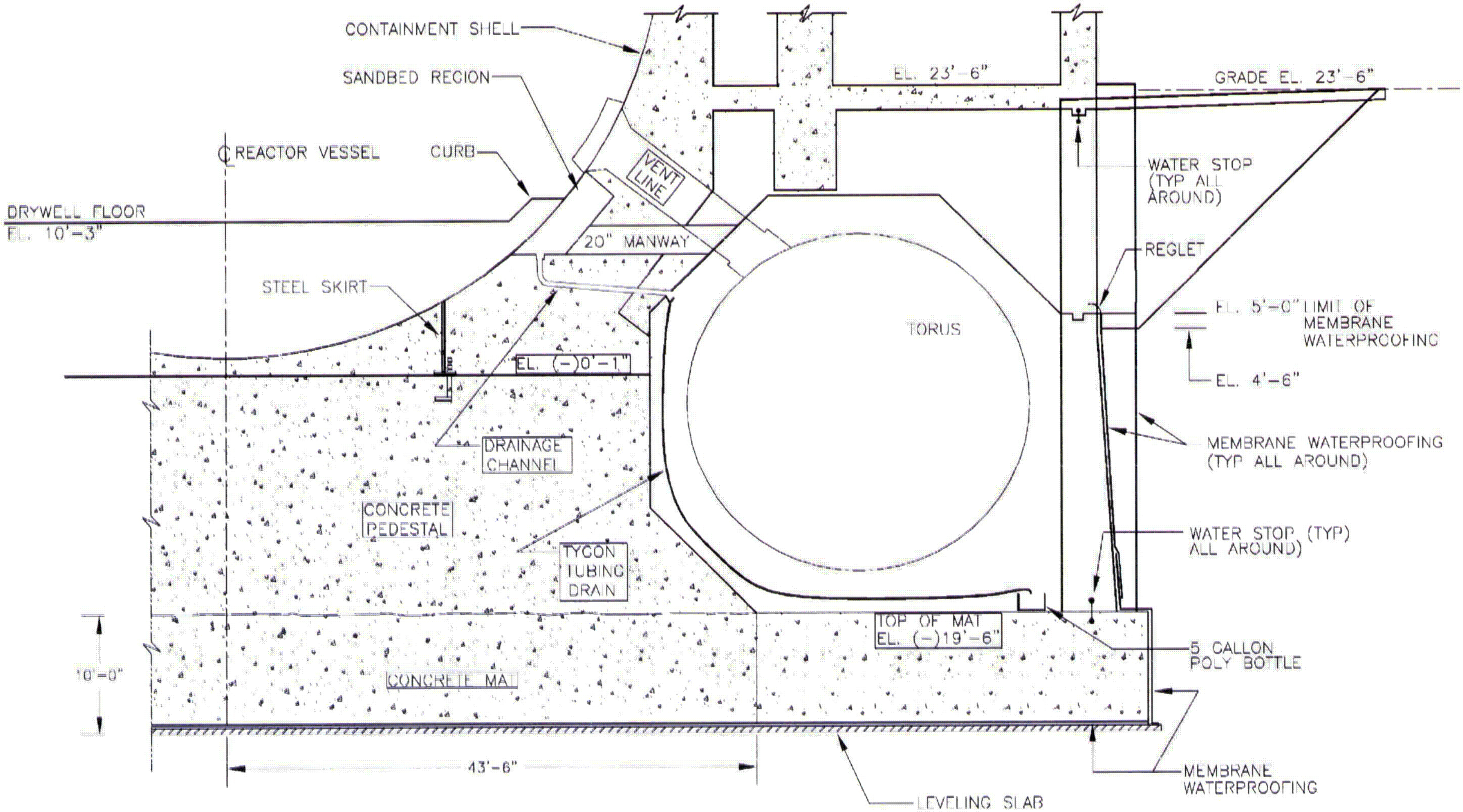

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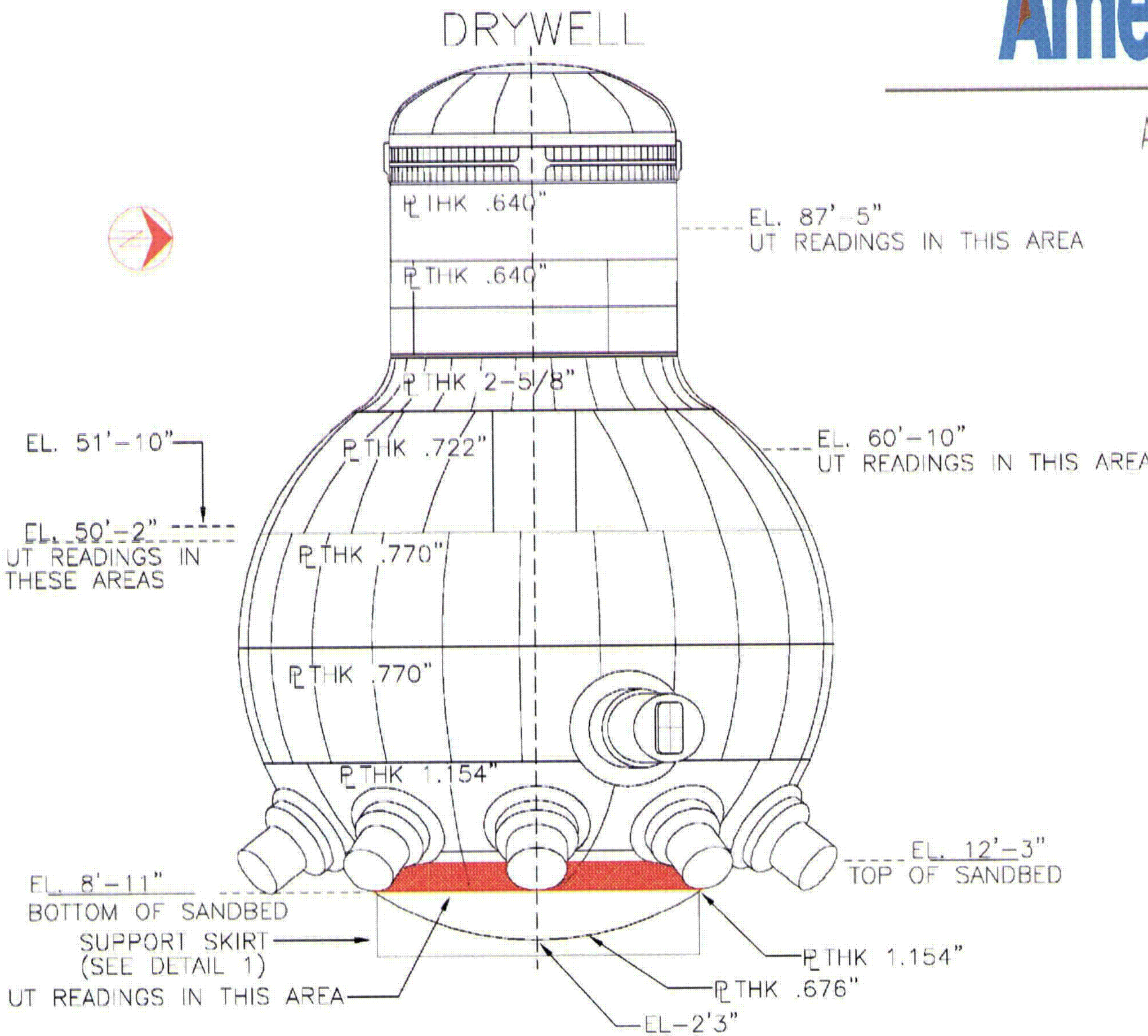

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# Cause and Corrective Actions

- Water accumulation in the sand bed region resulted in corrosion of the exterior surface of the drywell shell
- Corrective actions were completed in 1992
  - Prevented water intrusion into the sand bed region
  - Eliminated corrosive environment by removing the sand
  - Coated the drywell shell with epoxy in the sand bed region

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# Verification and Monitoring

- In 2006 refueling outage
  - Leakage from the reactor cavity liner, estimated at about 1 gpm, was captured by the drainage system
  - UT measurements of the drywell at 19 monitoring locations for the sand bed region showed no change in thickness
  - 100% visual inspection of the epoxy coating showed it to be in good condition
  - There was no water in the sand bed region

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# Verification and Monitoring

- In 2006 refueling outage
  - 106 UT measurements at locations measured in 1992, before epoxy coating applied, showed the drywell shell exceeds design thickness requirements
  - UT measurements at 13 locations in the upper elevations of the drywell show only 1 location with minimal ongoing corrosion (meets minimum required through 2029 with margin)

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# Drywell Shell Current Condition

| Drywell Region | Nominal Design Thickness, mils | Minimum Measured Thickness, mils | Minimum Required Thickness, mils | Minimum Available Thickness Margin, mils |
|---|---|---|---|---|
| Cylindrical | 640 | 604 | 452 | 152 |
| Knuckle | 2,625 | 2,530 | 2260 | 270 |
| Upper Sphere | 722 | 676 | 518 | 158 |
| Middle Sphere | 770 | 678 | 541 | 137 |
| Lower Sphere | 1154 | 1160 | 629 | 531 |
| Sand Bed | 1154 | 800 | 736 | 64 |

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# Drywell Thickness Analysis

Hardayal S. Mehta, Ph.D., P.E.
General Electric

# Drywell Analysis

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- Analysis completed in early 1990s
  - Without sand in the sand bed
- Modeling of the drywell
  - Loads and Load Combinations
- Buckling analysis
  - Controls the required drywell shell thickness in the sand bed region
  - Uniform drywell shell thickness of 736 mils over the entire sand bed region was used in the analysis
- ASME Section VIII stress analysis based on 62 psi
- Drywell pressure design basis change from 62 psi to 44 psi
  - Stress analysis of the drywell shell based on 44 psi

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# Modeling of the Drywell

# Drywell Configuration

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- Oyster Creek Drywell Geometry
  - It is 105'-6" high
  - Drywell head is 33' in diameter
  - Spherical section has an inside diameter of 70'
  - Ten vent pipes, 6'-6" in diameter, are equally spaced around the circumference to connect the drywell to the vent header inside the pressure suppression chamber
  - Drywell interior filled with concrete to elevation 10'-3" to provide a level floor
  - Base of the drywell is supported on a concrete pedestal conforming to the curvature of the vessel
  - Shell thicknesses vary
- Drywell shell, i.e., the sphere, cylinder, dome and transitions, was constructed from SA-212, Grade B Steel ordered to SA-300 spec.

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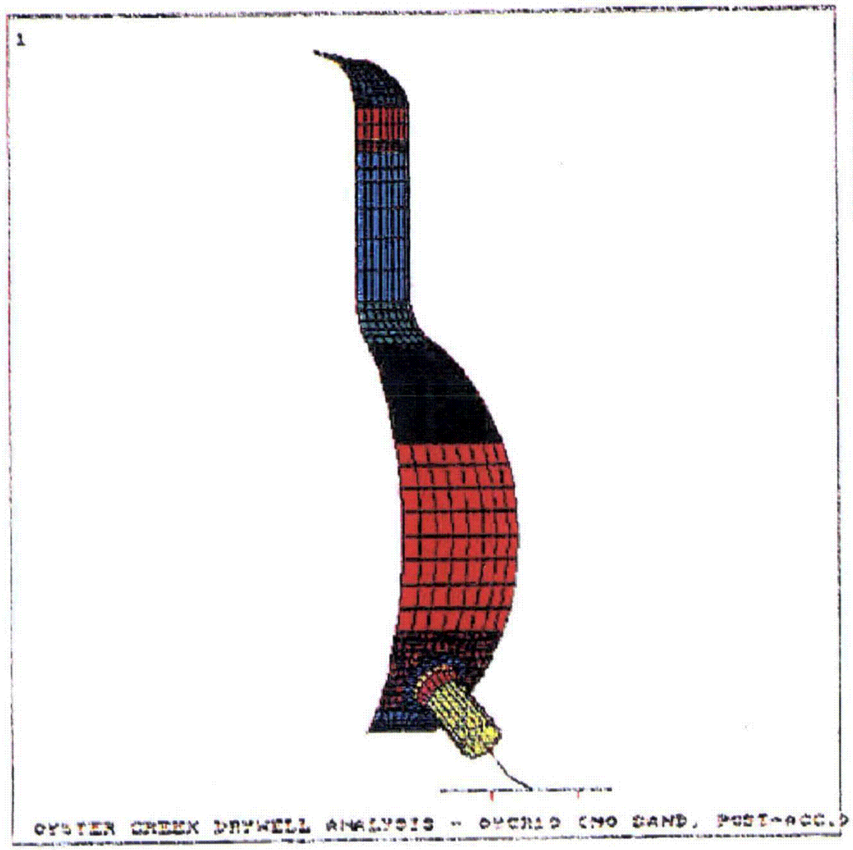
# Finite Element Models Used

- Axisymmetric, Beam and Pie Slice models used
- Axisymmetric drywell model used to evaluate
  - Unflooded and flooded seismic inertia loading
  - Thermal loading during postulated accident condition
- Beam drywell model used to evaluate stresses due to seismic relative support displacement
- Pie slice drywell model used for the Code and buckling evaluations
  - Vent lines included in the model
- No sand stiffness considered in any of the models

# Pie Slice Model and Load Application

- Taking advantage of symmetry of the drywell with 10 vent lines, a 36 degree section was modeled
  - The model included the drywell shell from base of the sand bed region to the top of the elliptical head and the vent and vent header
  - Drywell shell thickness in the sand bed region: 736 mils uniform

# Pie Slice model




ANSYS 4.4
DEC 4 1990
15:06:01
PLOT NO. 1
PREP7 ELEMENTS
REAL NUM

XV =1
YV =-0.8
DIST=718.786
XF =302.631
ZF =679.498
ANG2=-90
CENTROID HIDDEN

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# Applied Loads

- Gravity loading consists of dead weight loads, penetration loads, live loads
- Design pressure of 62 psi pressure (at 175°F)
  - Note 62 psi criterion was later changed to 44 psi per Tech. Spec. Amendment #165 (SER dated September 13, 1993)
- Seismic Loads
  - Inertia loads
  - Relative support displacement (Drywell and Reactor Building)

# Seismic Load Definition

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- Axisymmetric finite element model used to determine inertia loading
  - Drywell is constrained at the "reactor building/drywell/ star truss" interface at elevation 82'-6" and at its base
- Spectra at two locations: At the mat foundation and at the upper constraint
- Envelope spectrum used in ANSYS analysis

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# Load Combinations and Constituent Loads

| Load Combination | Constituent Loads |
|---|---|
| Normal Operating Condition | Gravity loads+ Pressure (2 psi external) + Seismic (2 x DBE) |
| Refueling Condition | Gravity loads + Pressure (2 psi external) + Water load +Seismic (2 x DBE) |
| Accident Condition | Gravity loads + Pressure (62 psi @ 175 deg. F or 35 psi @ 281 deg.F) + Seismic (2 x DBE) |
| Post-Accident Condition | Gravity loads + Water Load to El. 74' 6" + Seismic (2 x DBE) |

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# Buckling Analysis

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# Buckling Analysis Conclusion

- The buckling analysis was conducted using a uniform drywell shell thickness in the sand bed region of 736 mils.
- Stress limits and safety factors are in accordance with the Code requirements.
- The analysis shows that the drywell shell meets ASME Code Case N-284 requirements considering all design basis loads and load combinations.
- A locally thinned 12"x 12" area down to 536 mils was evaluated and determined not to have significant impact on buckling.
- The drywell shell thickness will be monitored using 736 mils as acceptance criteria for the minimum required general thickness and 536 mils as the minimum required local thickness.

# Buckling Analysis Details

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- Basic approach used in buckling evaluation followed the methodology outlined in ASME Code Case N-284

  Allowable Compressive Stress = $\eta_i \alpha_i \sigma_{ie}/FS$

  - FS is factor of safety (equal to 2.0 for refueling condition and 1.67 for post accident condition)
- Boundary conditions for buckling analysis
  - Symmetric at both edges (sym-sym)
  - Symmetric at one edge and asymmetric at the other edge (sym-asym)
  - Asymmetric at both the edges (asym-asym)
  - This captures all possible buckling mode shapes
- A uniform drywell shell thickness in the sand bed region of 736 mils was used in the buckling analysis

# Buckling Analysis Details

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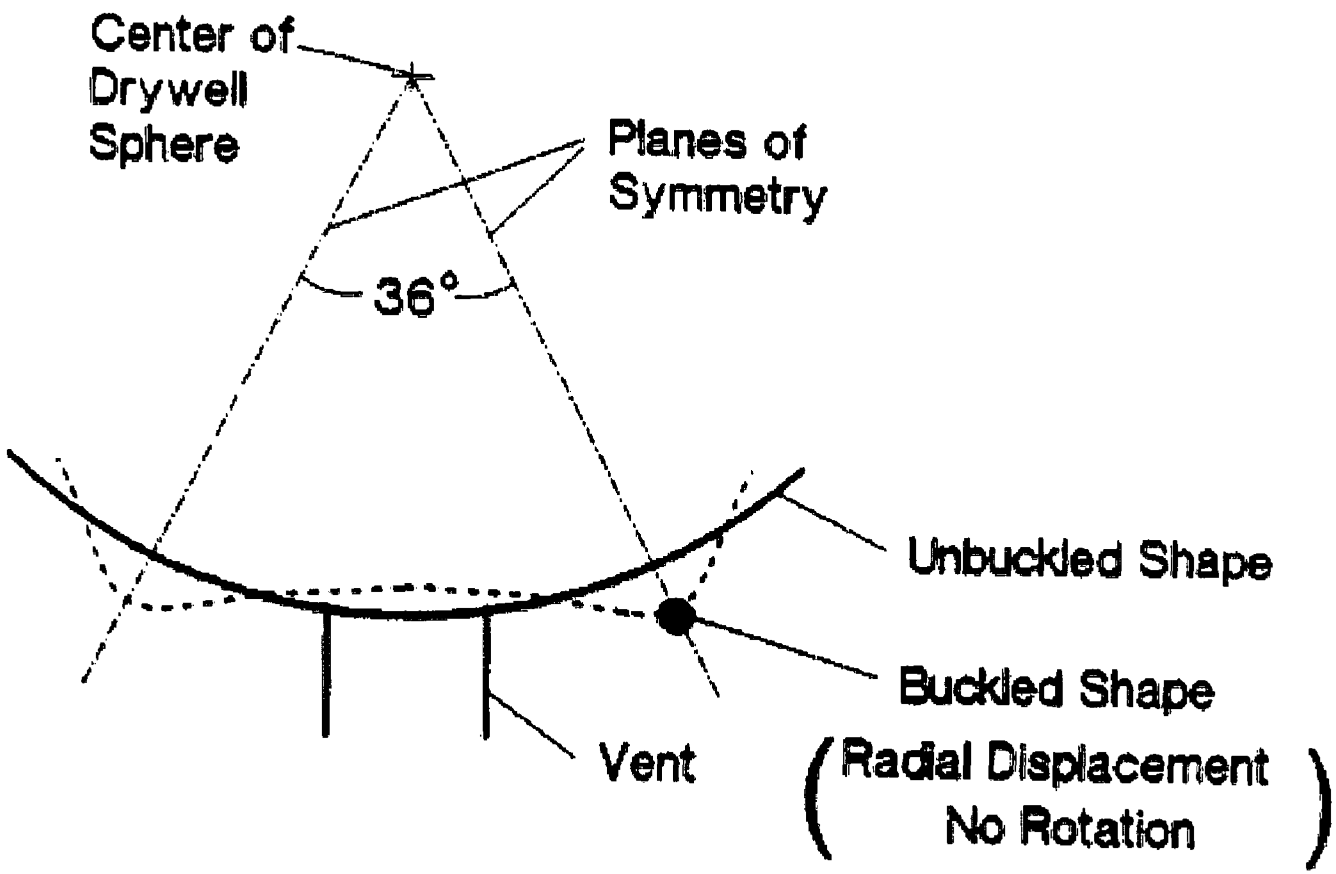
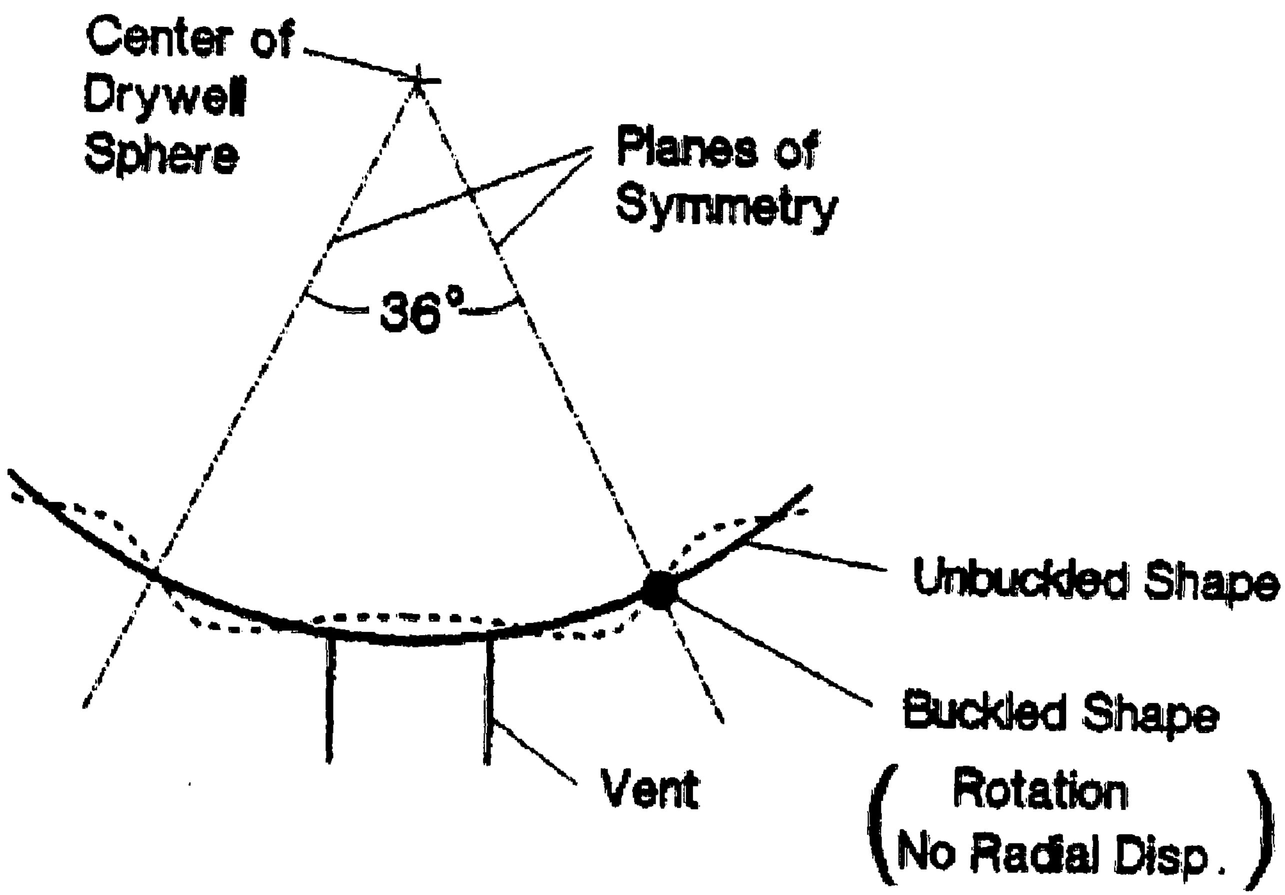



Symmetric Buckling of Drywell

# Buckling Analysis Details




Asymmetric Buckling of Drywell

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# Buckling Analysis Details

- Limiting load combination is the refueling condition
- Loads during refueling condition are
  - Gravity loads including weight of refueling water
  - External pressure of 2 psig
  - Seismic inertia and deflection loads for unflooded condition

# Buckling Analysis Details

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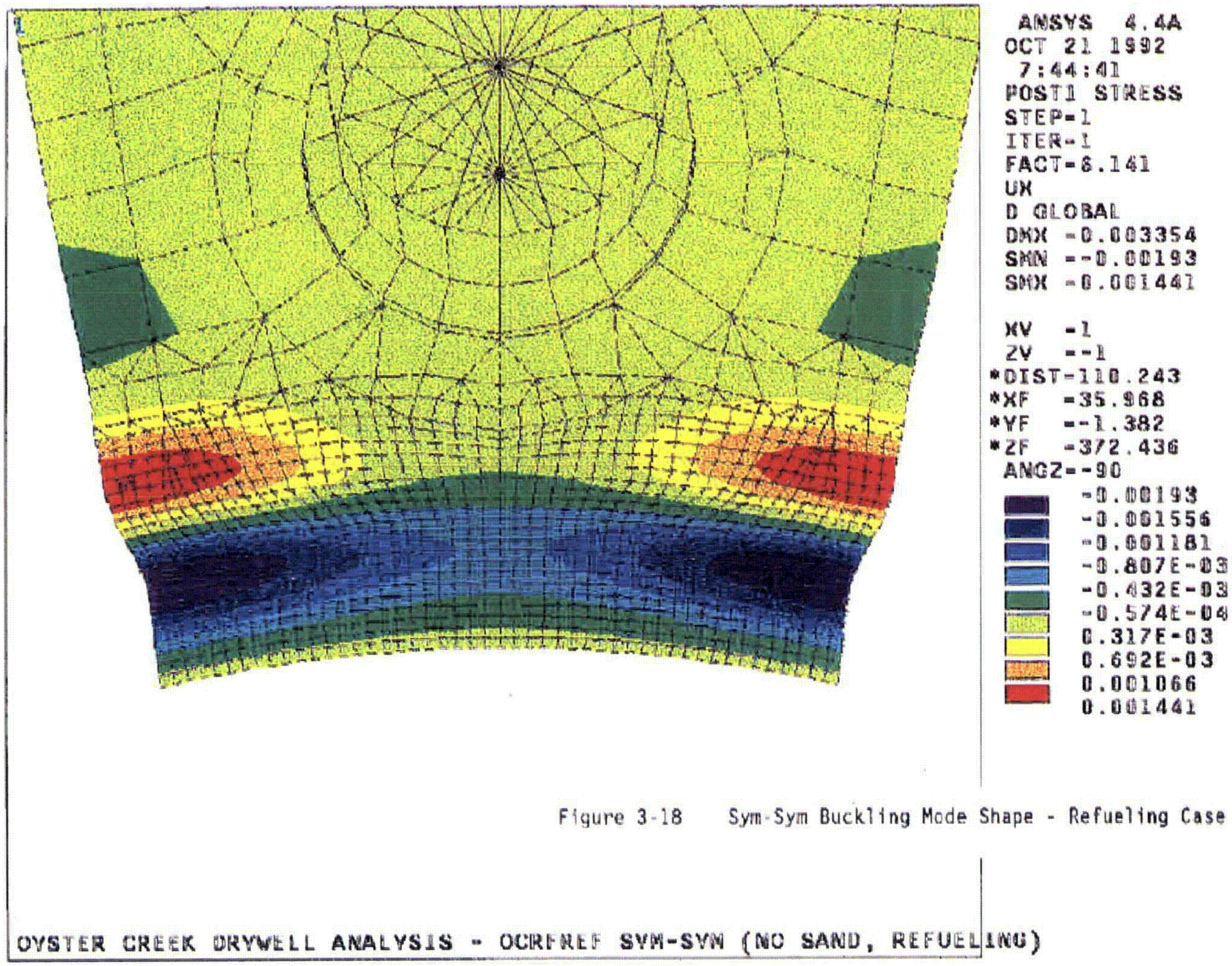


Figure 3-18 Sym-Sym Buckling Mode Shape - Refueling Case

# Buckling Analysis Details

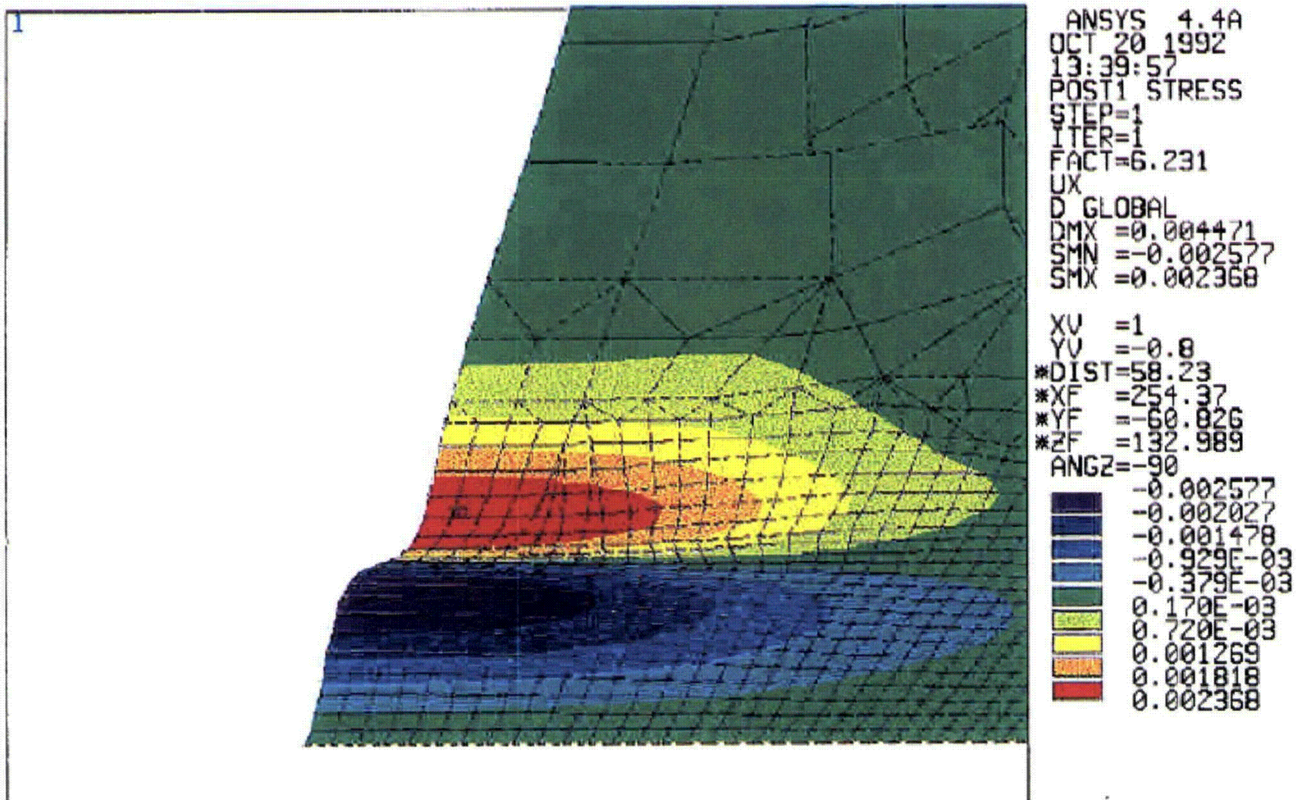


Figure 3-19 Sym-Asym Buckling Mode Shape - Refueling Case

OYSTER CREEK DRYWELL - ASYM - SYM , NO SAND, REFUELING

# Buckling Analysis Details

## Summary of Buckling Analysis Results – Refueling Case

| Parameter | Value |
|---|---|
| Theoretical Elastic Instability Stress, $\sigma_{ie}$ (ksi) | 46.59 |
| Capacity Reduction Factor, $\alpha_i$ | 0.207 |
| Circumferential Stress, $\sigma_c$ (ksi) | 4.51 |
| Equivalent Pressure, p (psi) | 15.81 |
| "X" Parameter | 0.087 |
| $\Delta C$ | 0.072 |
| Modified Capacity Reduction Factor, $\alpha_{i,mod}$ | 0.326 |
| Elastic Buckling Stress, $\sigma_e = \alpha_{i,mod}\ \sigma_{ie}$ (ksi) | 15.18 |
| Proportional Limit Ratio, $\Delta = \sigma_e / \sigma_y$ | 0.40 |
| Plasticity Reduction Factor, $\eta_i$ | 1.00 |
| Inelastic Buckling Stress, $\sigma_i = \eta_i\ \sigma_e$ (ksi) | 15.18 |
| Code Factor of Safety, FS | 2.0 |
| Allowable Compressive Stress, $\sigma_{all} = \sigma_i/FS$ (ksi) | 7.59 |
| Applied Compressive Meridional Stress, $\sigma_m$ (ksi) | 7.59 |

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# Evaluation of Local Thinning on Buckling Analysis - Sensitivity Study

- A locally 12”x12” thin area was modeled in the sand bed region drywell shell in the highest stress area, to determine the impact of local thinning on buckling stress
  - Establish minimum required local thickness down to 536 mils

Note: UT thickness measurements taken through 2006 show that locally thinned areas of the drywell shell are not coincident with high stress areas. The locally thinned areas are typically scattered below and near the vent headers. These areas are not highly stressed because of the additional stiffness provided by the vent header.

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# Buckling Analysis Conclusion

- The buckling analysis was conducted using a uniform drywell shell thickness in the sand bed region of 736 mils.
- Stress limits and safety factors are in accordance with the Code requirements.
- The analysis shows that the drywell shell meets ASME Code Case N-284 requirements considering all design basis loads and load combinations.
- A locally thinned 12"x 12" area down to 536 mils was evaluated and determined not to have significant impact on buckling.
- The drywell shell thickness will be monitored using 736 mils as acceptance criteria for the minimum required general thickness and 536 mils as the minimum required local thickness.

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# ASME Section VIII Stress Analysis

# ASME Section VIII Stress Analysis Conclusion

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- Stress analysis of the drywell shell was conducted in accordance with ASME Code and SRP 3.8.2 using reduced thicknesses due to corrosion.
- Stress limits and safety factors are in accordance with the ASME Code requirements.
- The analysis shows that the drywell shell meets ASME Code Stress requirements considering all design basis loads and load combinations.
- To regain margin, a plant specific analysis was conducted that reduced drywell design basis pressure from 62 psi to 44 psi (Tech Spec Amendment #165)
- The reduction in pressure resulted in a stress reduction of up to 5200 psi
- The minimum required general and local drywell shell thicknesses were calculated in accordance with ASME Code based on 44 psi pressure.
- The drywell shell thickness will be monitored for corrosion using the calculated minimum required general and local thicknesses as acceptance criteria.

# Codes and Standards

- The Oyster Creek drywell vessel was designed, fabricated and erected in accordance with the 1962 Edition of ASME Code, Section VIII and Code Cases 1270N-5, 1271N and 1272N-5
- Original Code of record and Code Cases do not provide specific guidance in two areas
- For the size of the region of increased membrane stress, guidance sought from Subsection NE of Section III
- For the Post-accident stress limits Standard Review Plan Section 3.8.2 was used as guidance

# Drywell – Section VIII Allowable Stresses

**Drywell Allowable Stresses**

| Stress Category | Allowable Stress Values (psi) | |
|---|---|---|
| | All Conditions Except Post-Accident | Post-Accident Condition* |
| General Primary Membrane | 19300 | 38000 |
| General Primary Membrane Plus Bending | 29000 | 57000 |
| Primary Plus Secondary | 52500 | 70000 |

* Allowable values based on Standard Review Plan Section 3.8.2, Steel Containment

# Code Stress Evaluation Results

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## (based on 62 psi, 1993)

**Primary Stress Evaluation**

| Drywell Region | Stress Category | Calculated Stress Magnitude (psi) | Allowable Stress (psi) | Percent Margin |
|---|---|---|---|---|
| Cylinder (t=0.619 in.) | Primary Membrane | 19850 | 21200* | 6 |
| | Primary Memb.+Bending | 20970 | 29000 | 28 |
| Upper Sphere (t=0.677 in.) | Primary Membrane | 20360 | 21200* | 4 |
| | Primary Memb.+Bending | 28100 | 29000 | 3 |
| Middle Sphere (t=0.723 in.) | Primary Membrane | 19660 | 21200* | 7 |
| | Primary Memb.+Bending | 24610 | 29000 | 15 |
| Lower Sphere (t=1.154 in.) | Primary Membrane | 13940 | 21200* | 34 |
| | Primary Memb.+Bending | 17640 | 29000 | 39 |
| Sand Bed (t=0.736 in.) | Primary Membrane | 16540 | 21200* | 22 |
| | Primary Memb.+Bending | 23130 | 29000 | 20 |

* This is (1.1x19300) and is the threshold for local primary membrane stress per NE-3213.10

# Regain Margin through Licensing Basis Change

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- The drywell pressure of 62 psi was very conservative
- Analysis was conducted in early 1990's to establish Oyster Creek specific drywell design pressure.
  - Design pressure changed from 62 psi to 44 psi.
    - 44 psi is based on conservatively calculated peak drywell pressure of 38.1 psi plus an added 15% allowance.
  - The change was approved by NRC per Technical Specification Amendment No. 165 (SER dated September 13, 1993).
  - The reduction in pressure resulted in a pressure stress reduction of up to 5200 psi
- Recalculated the required drywell shell thicknesses based on 44 psi to regain thickness margin.

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# Primary Membrane Stress Comparison 62 psi vs. 44 psi

| Drywell Region | Time Frame | As-analyzed Thickness (mils) | Stress Category | Calculated Stress (psi) | Allowable Stress (psi) | Stress Margin (%) |
|---|---|---|---|---|---|---|
| Cylinder | 1993 | 619 | Primary Membrane | 19, 850 | 21,200 | 6 |
| | 2006 | 604 | Primary Membrane | 14,446 | 19,300 | 25 |
| Upper Sphere | 1993 | 677 | Primary Membrane | 20,360 | 21,200 | 4 |
| | 2006 | 676 | Primary Membrane | 14,796 | 19,300 | 23 |
| Middle Sphere | 1993 | 723 | Primary Membrane | 19,660 | 21,200 | 7 |
| | 2006 | 678 | Primary Membrane | 15,499 | 19,300 | 20 |
| Lower Sphere | 1993 | 1154 | Primary Membrane | 13,940 | 21,200 | 34 |
| | 2006 | 1154 | Primary Membrane | 10,660 | 19,300 | 45 |
| Sand Bed | 1993 | 736 | Primary Membrane | 16,540 | 21,200 | 22 |
| | 2006 | 736 | Primary Membrane | 11,404 | 19,300 | 41 |

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# Minimum Required Drywell Shell Thickness

- Minimum required general thickness for 44 psi
  - Calculated based on primary membrane stresses for 62 psi, adjusted for pressure reduction (62 psi to 44 psi)
- Minimum required local thickness for 44 psi
  - Calculated based on ASME Section III provisions which allow increase in allowable local primary membrane stress from 1.0 Smc to 1.5 Smc
  - Local thickness criteria is applicable to an area of 2.5" in diameter and less consistent with ASME Section III, Subsection NE-3332.1
  - Extent of Locally thinned areas is evaluated per ASME Section III, Subsection NE-3213.10, NE-3332.2, and NE-3335.1

# Minimum Required Thicknesses Based on 44 psi pressure

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| Drywell Region | Design Nominal Thickness, mils | Minimum Measured General Thickness Thru 2006, mils | Minimum Required General Thickness, mils | Minimum Required Local Thickness, mils |
|---|---|---|---|---|
| Cylinder | 640 | 604 | 452 | 301 |
| Upper Sphere | 722 | 676 | 518 | 345 |
| Middle Sphere | 770 | 678 | 541 | 360 |
| Lower Sphere | 1154 | 1160 | 629 | 419 |
| Sand Bed | 1154 | 800 | 479(1) | 319(2) |

(1) The minimum required general drywell shell thickness in the sand bed region is 736 mils, controlled by buckling.

(2) Acceptance criteria for evaluating locally thinned areas of the drywell shell in the sand bed region is conservatively based on 490 mils instead of 319 mils

# ASME Section VIII Stress Analysis Conclusion

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- Stress analysis of the drywell shell was conducted in accordance with ASME Code and SRP 3.8.2 using reduced thicknesses due to corrosion.
- Stress limits and safety factors are in accordance with the ASME Code requirements.
- The analysis shows that the drywell shell meets ASME Code Stress requirements considering all design basis loads and load combinations.
- To regain margin, a plant specific analysis was conducted that reduced drywell design basis pressure from 62 psi to 44 psi (Tech Spec Amendment #165)
- The reduction in pressure resulted in a stress reduction of up to 5200 psi
- The minimum required general and local drywell shell thicknesses were calculated in accordance with ASME Code based on 44 psi pressure.
- The drywell shell thickness will be monitored for corrosion using the calculated minimum required general and local thicknesses as acceptance criteria.

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# Sand Bed Region

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# Sand Bed Region Conclusions

- Corrosion on the outside of the drywell shell in the sand bed region has been arrested
- The coating shows no degradation
- There is sufficient margin to the minimum thickness requirement (64 mils margin above code required average thickness of 736 mils)

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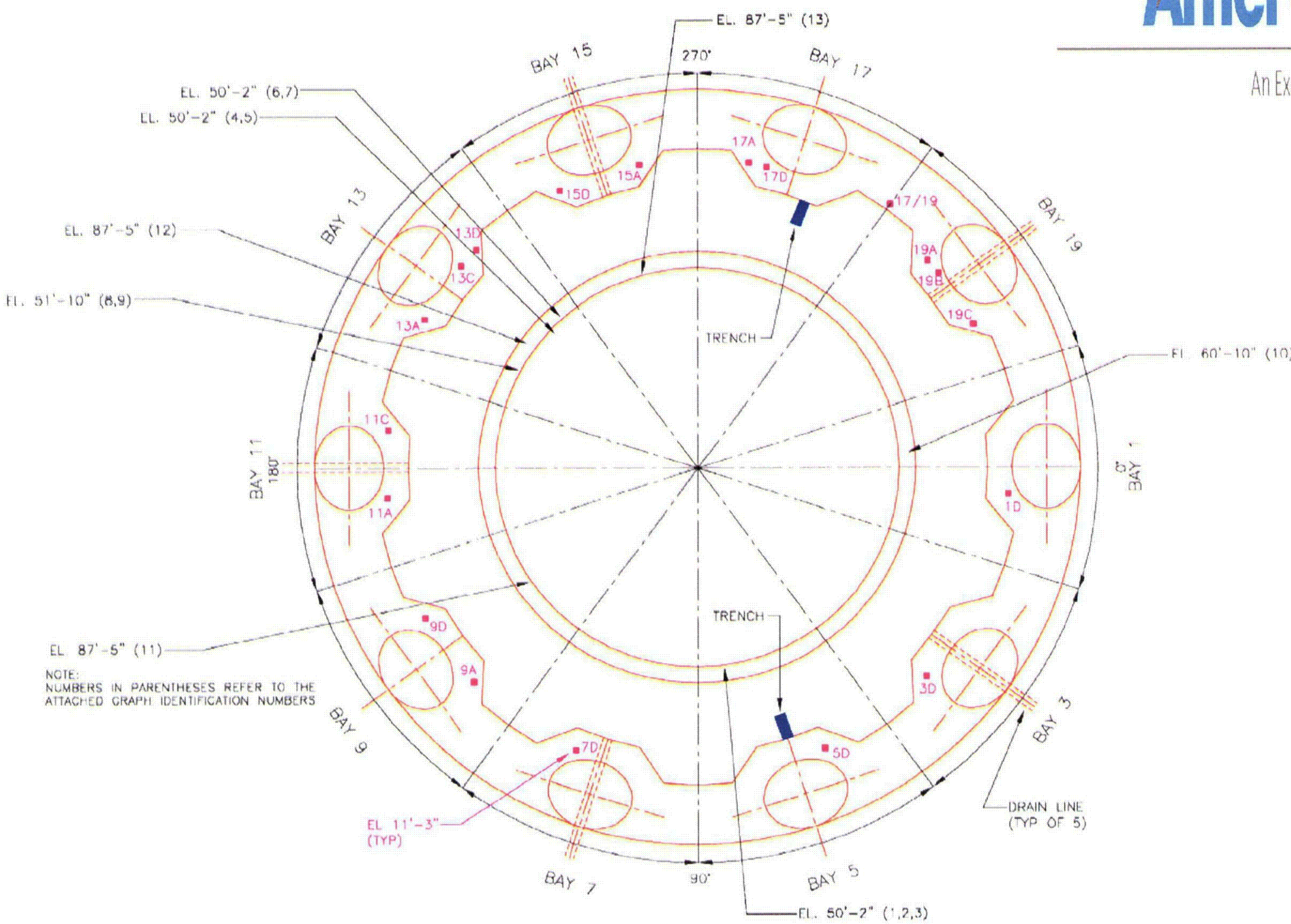
# Background and History

## Sand Bed Internal UTs

- 1983 to 1986 corrosion data 360° at elev. 11'3"
  - When thin locations were identified, UT measurements were taken horizontally and vertically to locate the thinnest locations
  - UT grid measurements were taken at the thinnest locations
  - 19 locations were selected for corrosion monitoring based on over 500 initial data points measured
  - At least one grid is located in each of the 10 bays



EL. 87'-5" (13)
270°
BAY 15
BAY 17
EL. 50'-2" (6,7)
EL. 50'-2" (4,5)
EL. 87'-5" (12)
EL. 51'-10" (8,9)
BAY 13
BAY 19
15A
15D
17A
17D
17/19
13D
13C
13A
19A
19B
19C
TRENCH
EL. 60'-10" (10)
11C
11A
BAY 11
180°
BAY 1
0°
1D
TRENCH
9D
9A
3D
EL. 87'-5" (11)
NOTE:
NUMBERS IN PARENTHESES REFER TO THE ATTACHED GRAPH IDENTIFICATION NUMBERS
BAY 9
BAY 3
7D
5D
EL 11'-3"
(TYP)
DRAIN LINE
(TYP OF 5)
BAY 7
90°
BAY 5
EL. 50'-2" (1,2,3)


KEY PLAN

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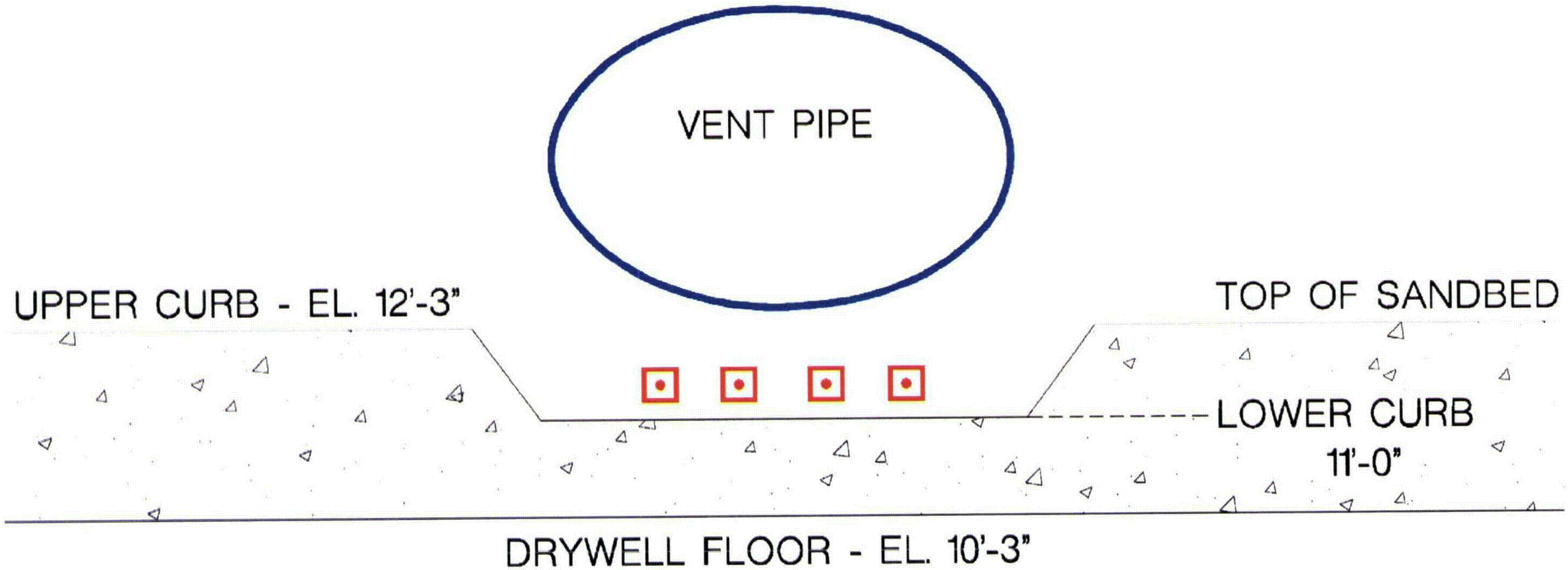
# VIEW FROM INSIDE DRYWELL



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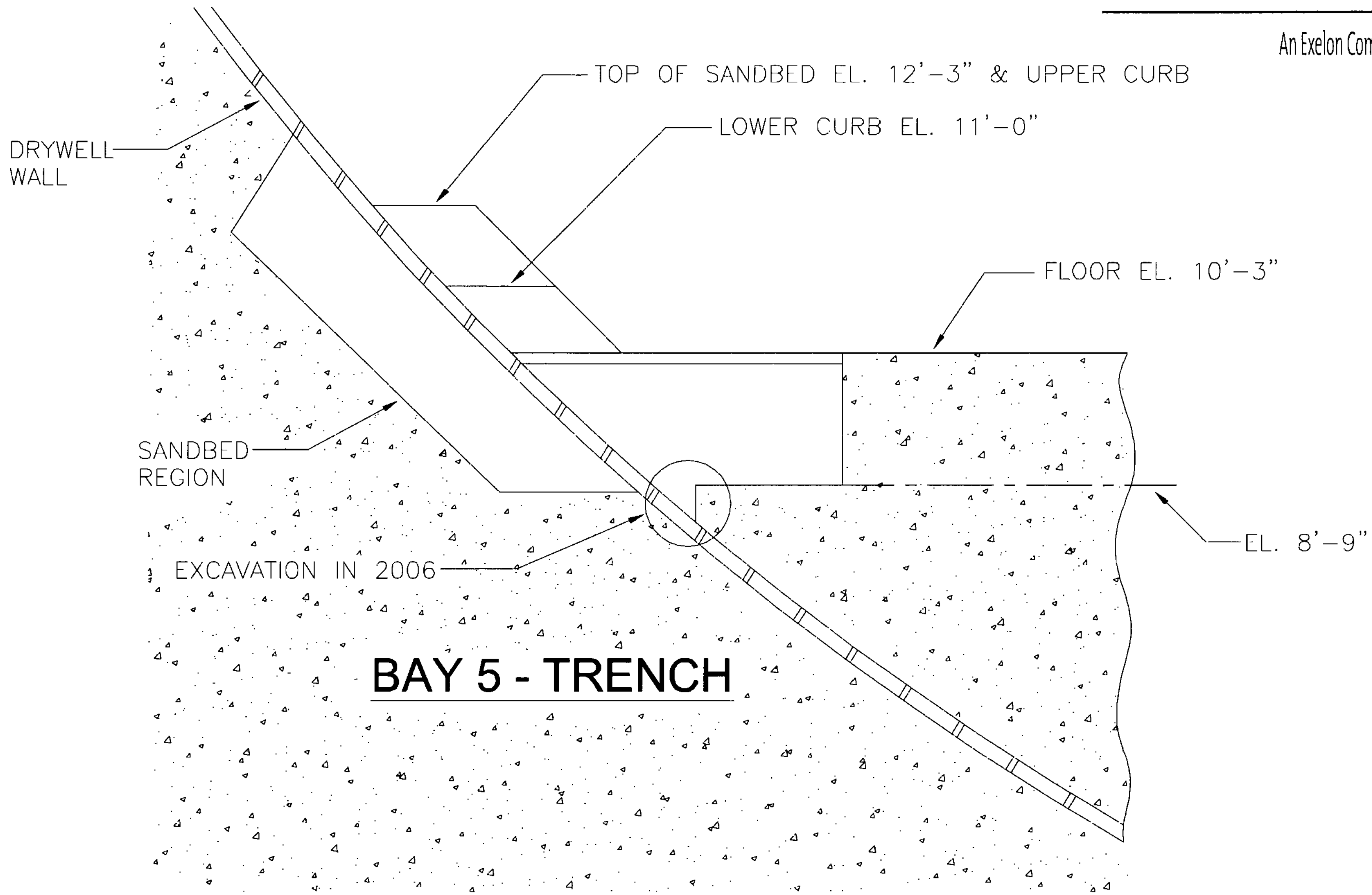

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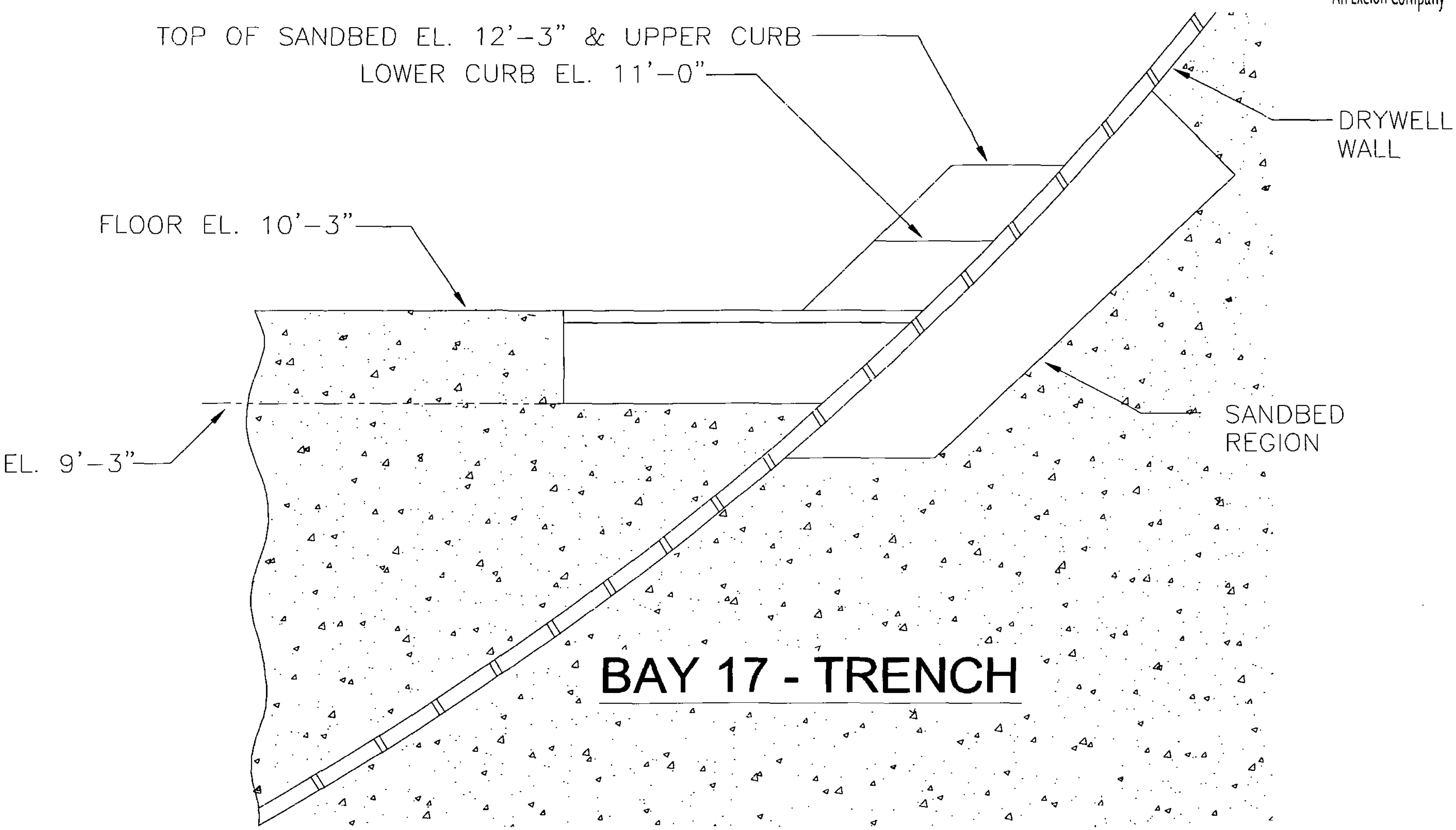

# Sand Bed Region Background and History

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- Trenches in bays 5 and 17 were excavated in 1986 to determine corrosion in sand bed at elevations below the drywell interior floor
  - Bays 5 and 17 were selected because UT measurements indicated these bays had the least and the most corrosion, respectively
  - The trenches extend to about the elevation of the bottom of the sand bed
  - UT measurements taken in the trenches confirmed that the corrosion below elev. 11' 3" was bounded by the monitoring at elev. 11' 3"

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# 2006 Inspection Data

## General Thickness (mils)

| | Bay 5 | Bay 17 | | | | |
|---|---|---|---|---|---|---|
| **Grid** | **5D** | **17A Top** | **17A Bottom** | **17D** | **17/19 Top** | **17/19 Bottom** |
| **Grid Elev. 11'3" Above Lower Curb** | 1185 | 1122 | 935 | 818 | 964 | 972 |
| **Trench Lower Curb to Sand Bed Floor** | 1074 | 986 | | | | |
| **Trench Below Sand Bed Floor** | 1113 | N/A | | | | |

# Sand Bed Region Background and History

- Sand was removed in 1992 and the shell was cleaned
- External UT measurements were taken in all bays at thinned local areas (as determined by visual inspection)
- The shell was coated with  epoxy coating
- UT grid measurements were taken at the 19 monitored locations at elev. 11’3” as a baseline for the new condition

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# Condition of the Drywell Shell in the Sand Bed Region After Sand Removal

# Sand Bed Region 1992

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Drywell
Shell

Corrosion product on drywell vessel

# Sand Bed Region 1992

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Drywell Shell

As found condition of floor bed

# Condition of the Drywell Shell in the Sand Bed Region After Application of Epoxy Coating

# Sand Bed Region 1992

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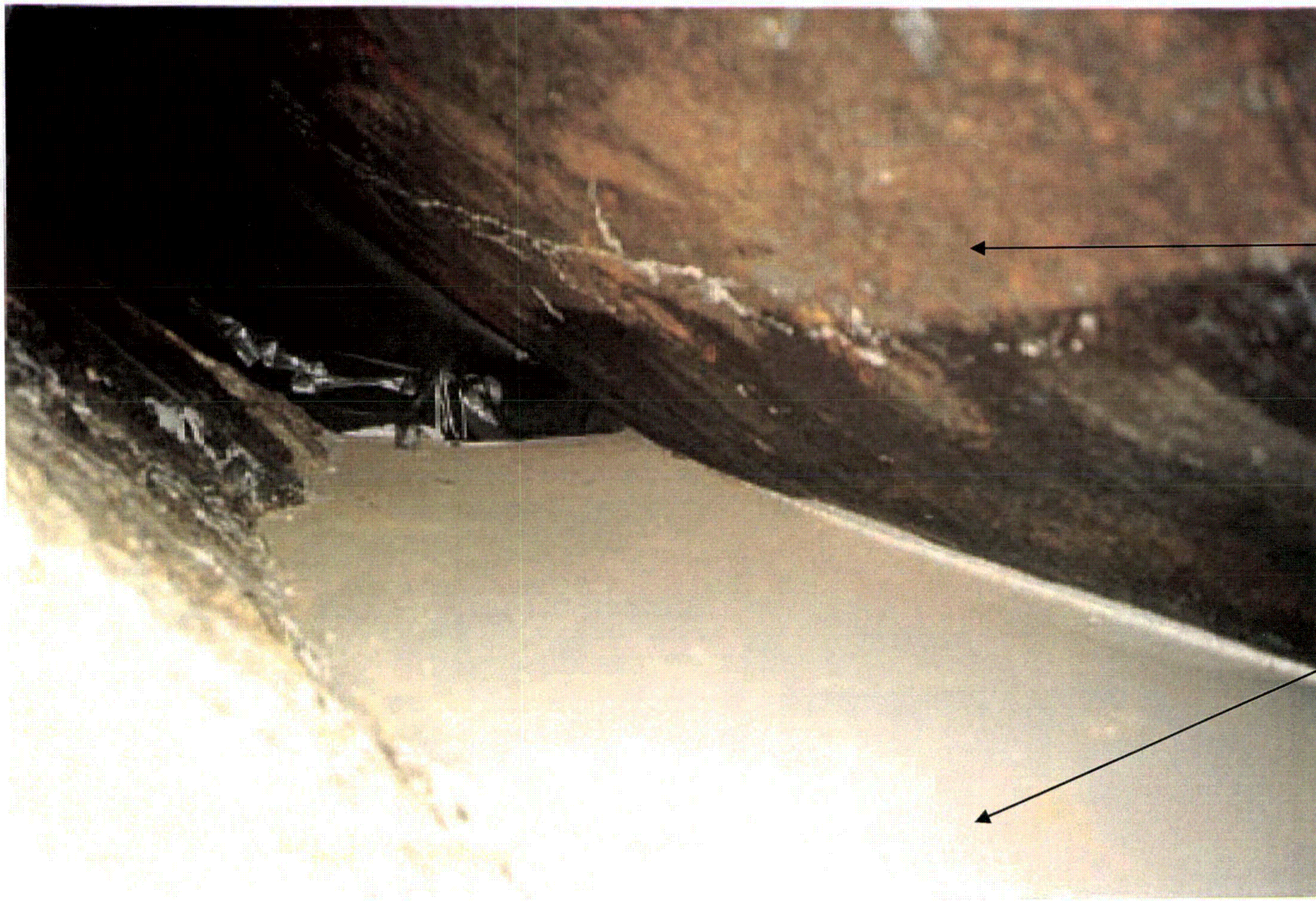


Bay 5 before shell coating

# Sand Bed Region 1992

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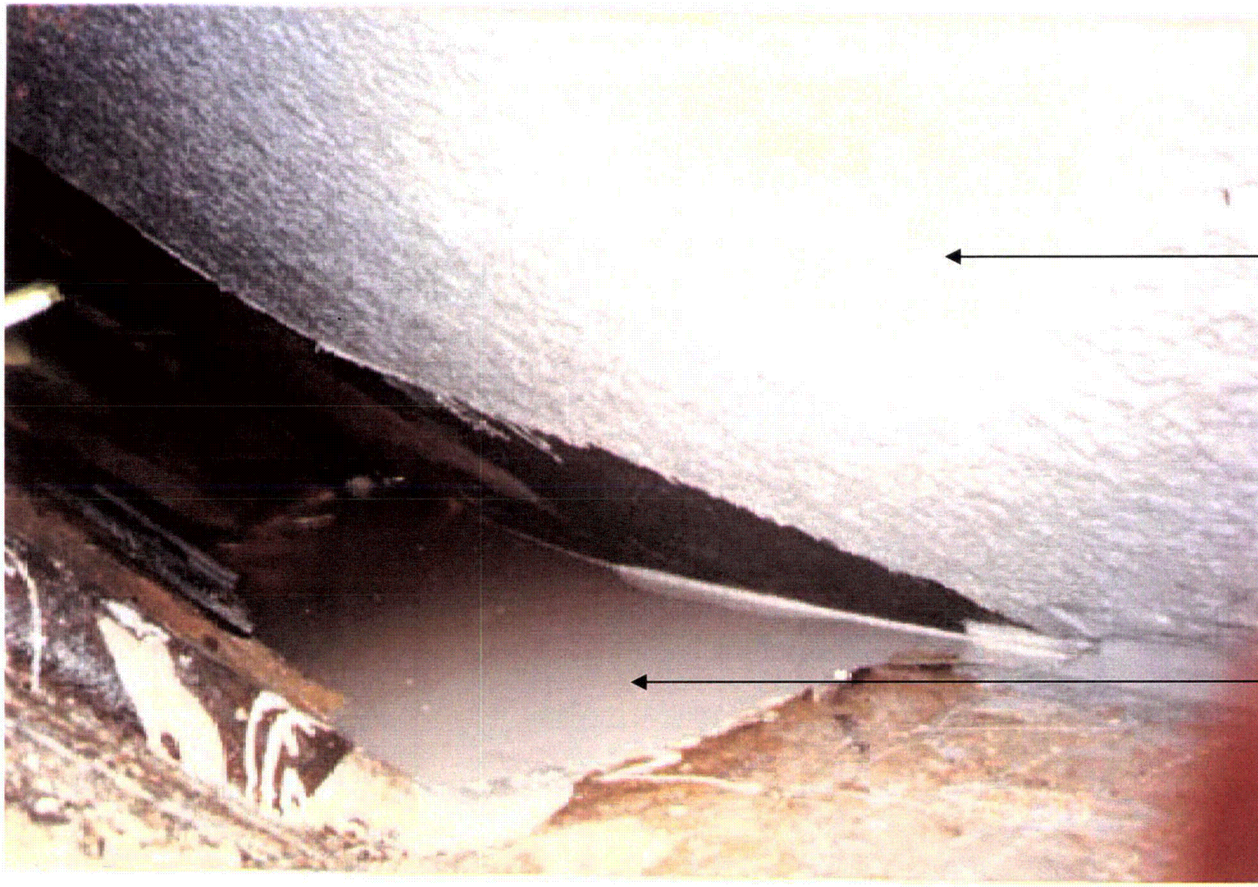


Shell and floor undergoing coating and repairs

# Sand Bed Region 1992

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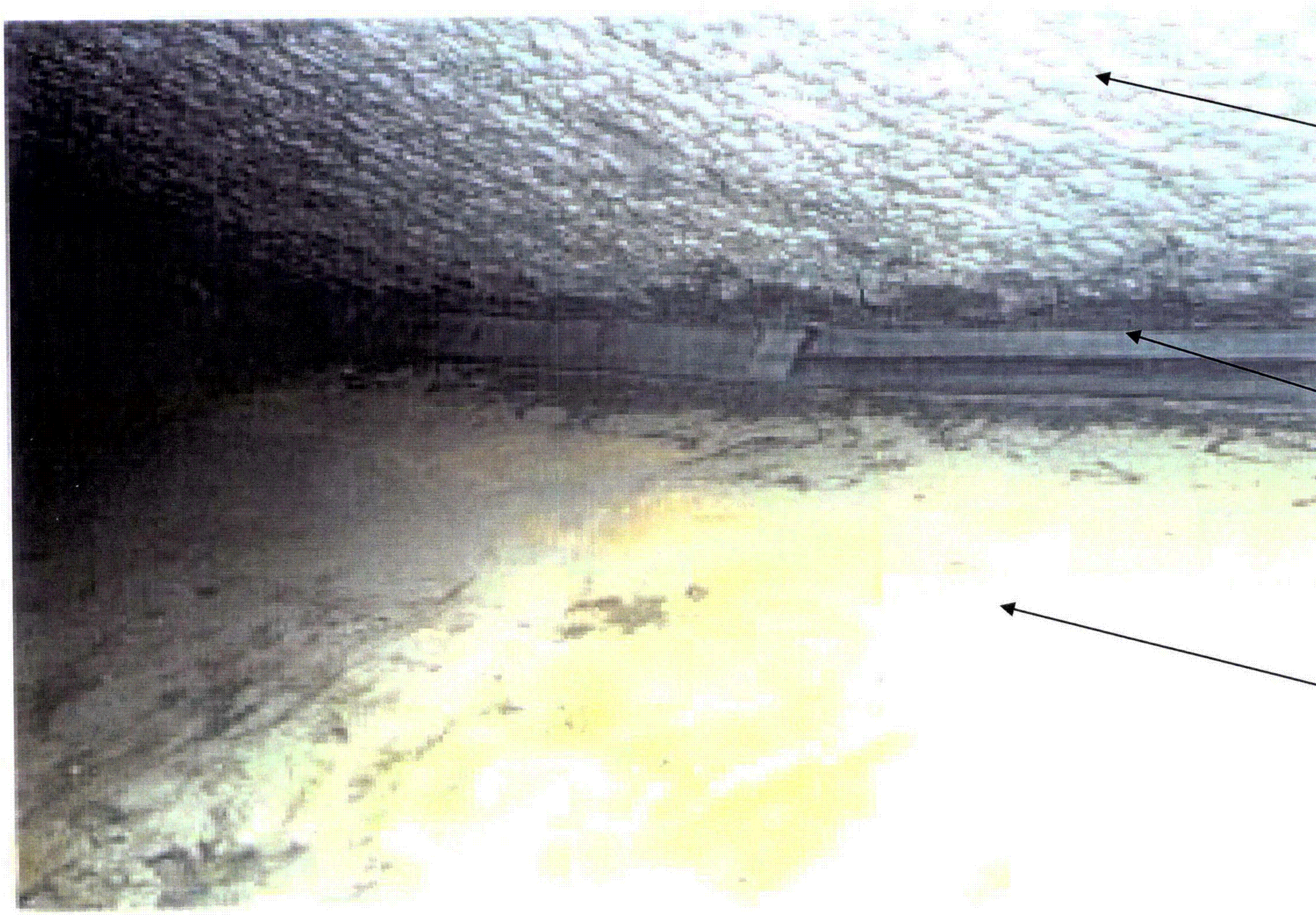


Finished floor, vessel with two top coats – caulking material applied

# Sand Bed Region Background and History

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- DEVOE Epoxy coating system (3 part)
  - Designed for application on corroded surfaces
  - One coat DEVOE 167 Rust Penetrating Sealer
    - Penetrates rusty surfaces
    - Reinforces rusty steel substrates
    - Ensures adhesion of Devran 184 epoxy coating

# Sand Bed Region Background and History

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- DEVOE Epoxy coating system
  - Two coats Devran 184 epoxy coating
    - Designed for tank bottoms, including water tanks, fuel tanks, selected chemical tanks
    - Coating application was tested in a mock-up for coating thickness and absence of holidays or pinholes
    - Two coats used to minimize any chance of pinholes or holidays
    - The two coats are different colors

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# Use of Coatings to Prevent Corrosion

Jon R. Cavallo, PE, PCS

Vice President

Corrosion Control Consultants and Labs, Inc.

# Background and History

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- The OCNGS Protective Coatings Monitoring and Maintenance Program aging management program is consistent with NUREG 1801, Rev. 1 (the GALL Report), Appendix XI.S8
  - NUREG 1801, Appendix XI.S8 only covers Coating Service Level I coatings
- In addition, the OCNGS Coating Monitoring and Maintenance Program includes the Coating Service Level II coatings applied to exterior of drywell in Sand Bed region

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# Background and History

- Inspection and evaluation of OCNGS external coated drywell Sand Bed region surfaces (Coating Service Level II Coatings) is conducted in accordance with ASME Section XI, Subsection IWE by qualified VT inspectors.
  - Areas shall be examined (as a minimum) for flaking, blistering, peeling, discoloration and other signs of distress.
- The premise of ASME Section XI, Subsection IWE is that degradation of a steel substrate will be indicated by the presence of visual anomalies in the attendant protective coatings

# How Barrier Coating Systems Prevent Corrosion

- Barrier coating systems separate the electrolyte from the anodes, cathodes and conductors
- A barrier coating system has been applied to the steel substrate in the OCGS Sand Bed region

# Technical Review of OCGS Sand Bed Region Coating System

- The OCGS Sand Bed region barrier coating system consists of:
  - Devoe Pre-Prime 167 penetrating sealer
  - Devoe Devran 184 mid- and top-coat
  - Devoe Devmat 124S caulk

  and is appropriate for the intended service

# Technical Review of OCGS Sand Bed Region Coating System

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- With periodic condition assessment and maintenance (if required), the OCNGS Sand Bed region coating system will continue to prevent corrosion of the steel substrate for the period of extended operation
- Oyster Creek inspected 100% of the Sand Bed region coating in 2006 and will inspect at least three bays every other outage, with all 10 inspected every 10 years
- The 10 year inspection periodicity cycle is appropriate and commensurate with the Sand Bed Region environment and industry experience
  - EPRI 1003102, "Guideline on Nuclear Safety-Related Coatings"

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# UT Thickness Measurements In the Sand Bed

Pete Tamburro

Oyster Creek Engineering

# Background and History

## Sand Bed Region

- UT grid measurements were taken at the 19 monitored locations at elev. 11'3" as a baseline for the new condition in 1992
- In 1992, thinnest grid average thickness 800 mils vs. criterion of 736 mils
- In 1992, thinnest local reading 618 mils vs. criterion of 490 mils

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# Background and History
## Sand Bed Region

- 19 grids repeated in 1994 and 1996
  - Statistically, no changes in thickness were observed
  - Basis for corrosion "arrested" in the sand bed region, on outer surface of the drywell
  - Basis for NRC SER concluding that further UT measurements are not needed and visual inspection of the coating is sufficient
- The 2006 UT measurements confirmed that corrosion has been arrested

# UT Measurements of 6"x6" Grid

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## Sand Bed Region

- Measurement locations are marked on the inside of the drywell shell
- Use a stainless steel template with 49 holes to align the UT probe
- UT probe placed perpendicular to the surface to consistently obtain lowest reading
- A protective grease is applied to the 6"x6" grid during operation, and removed to take UT measurements

# Statistical Methodology

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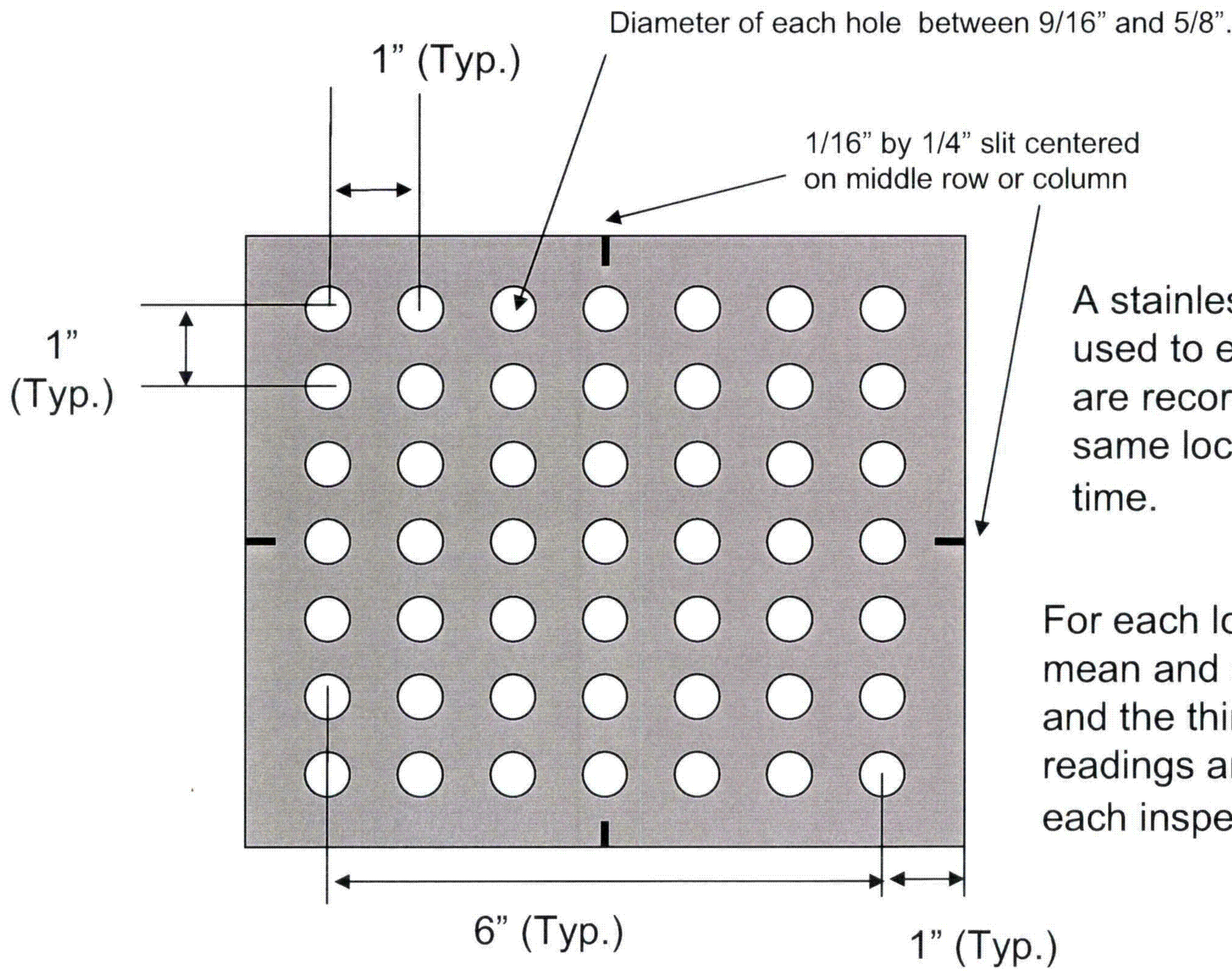
**49 UT readings are recorded over a 6" by 6" area.**




A stainless steel template is used to ensure that the readings are recorded consistently and in same location (+/- 1/16") every time.

For each location, the mean and standard error and the thinnest of the 49 readings are calculated after each inspection.

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# Statistical Methodology

- Because of roughness of the exterior surface of the drywell shell in the sand bed, there is uncertainty in the mean thickness calculated for each grid location
- The major contributor to the uncertainty in the means is the variance from point to point due to the rough surface and not inaccuracy or repeatability of the UT Instrumentation

# Statistical Methodology

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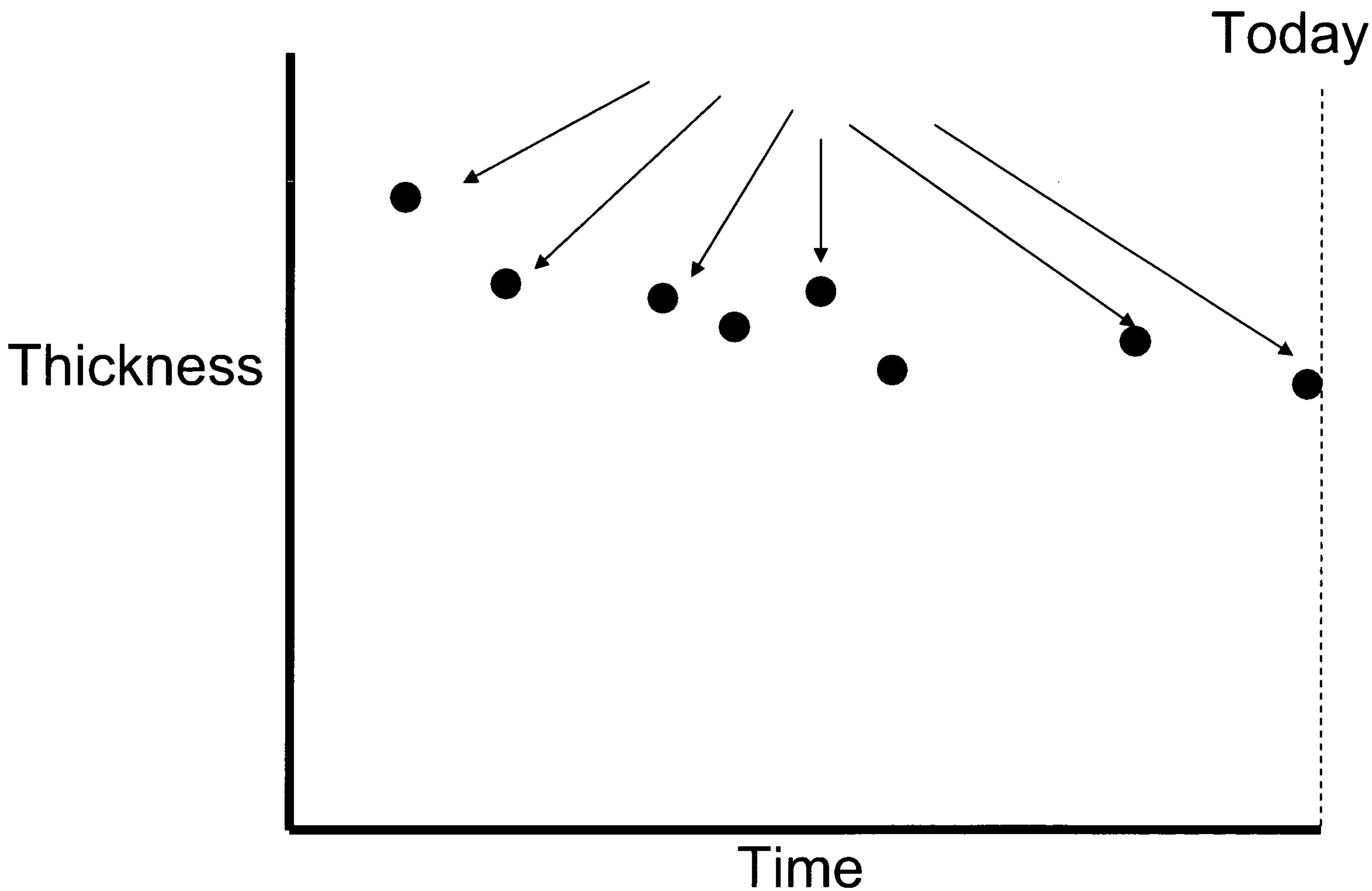
**For each location the means and thinnest points are trended over time**



# Statistical Methodology

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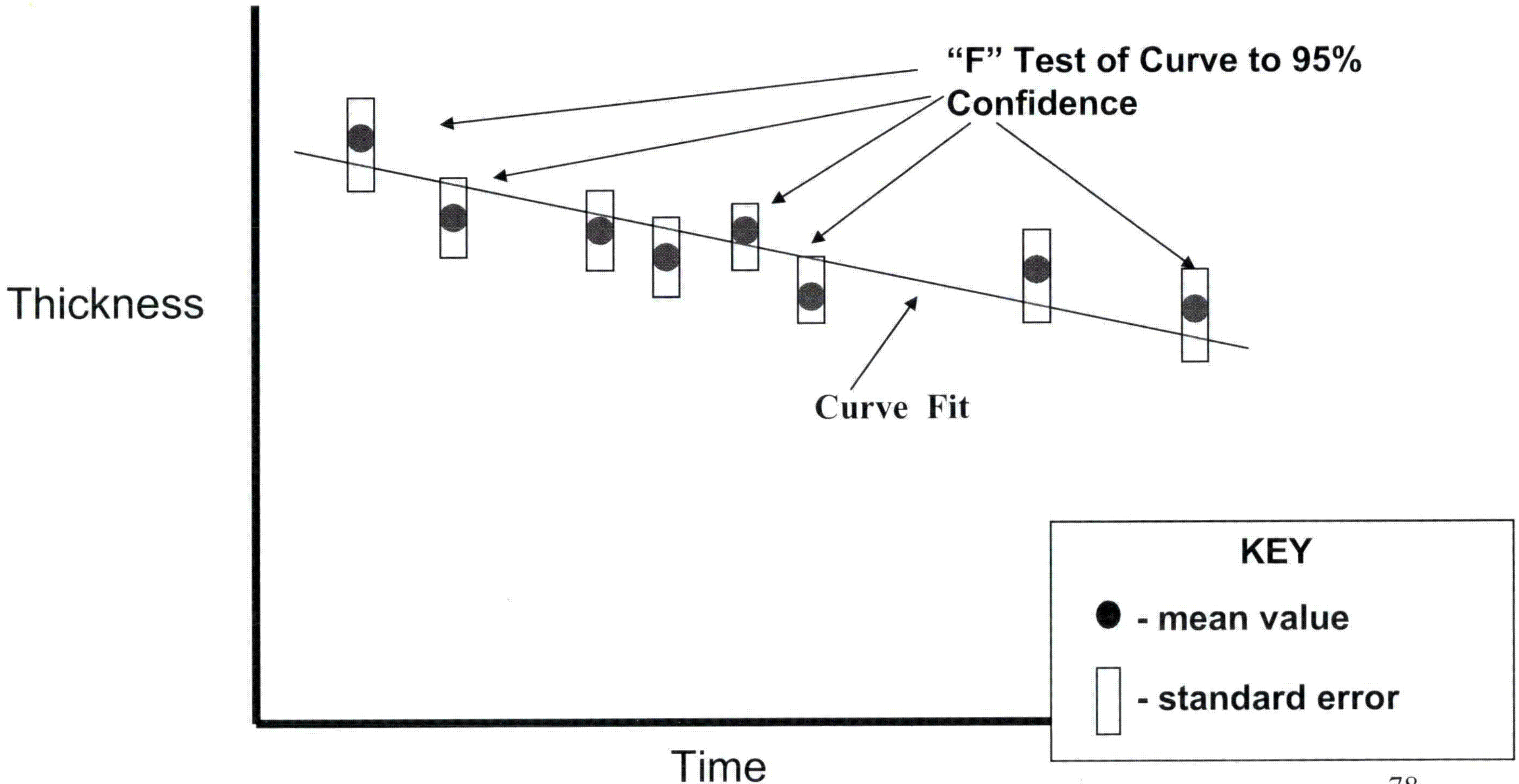
1) A curve fit based on the regression model is then developed.

2) The Corrosion "F" Test is performed to determine if the data meet the curve fit with 95% confidence.



## Projection Based on Successful Corrosion F tests

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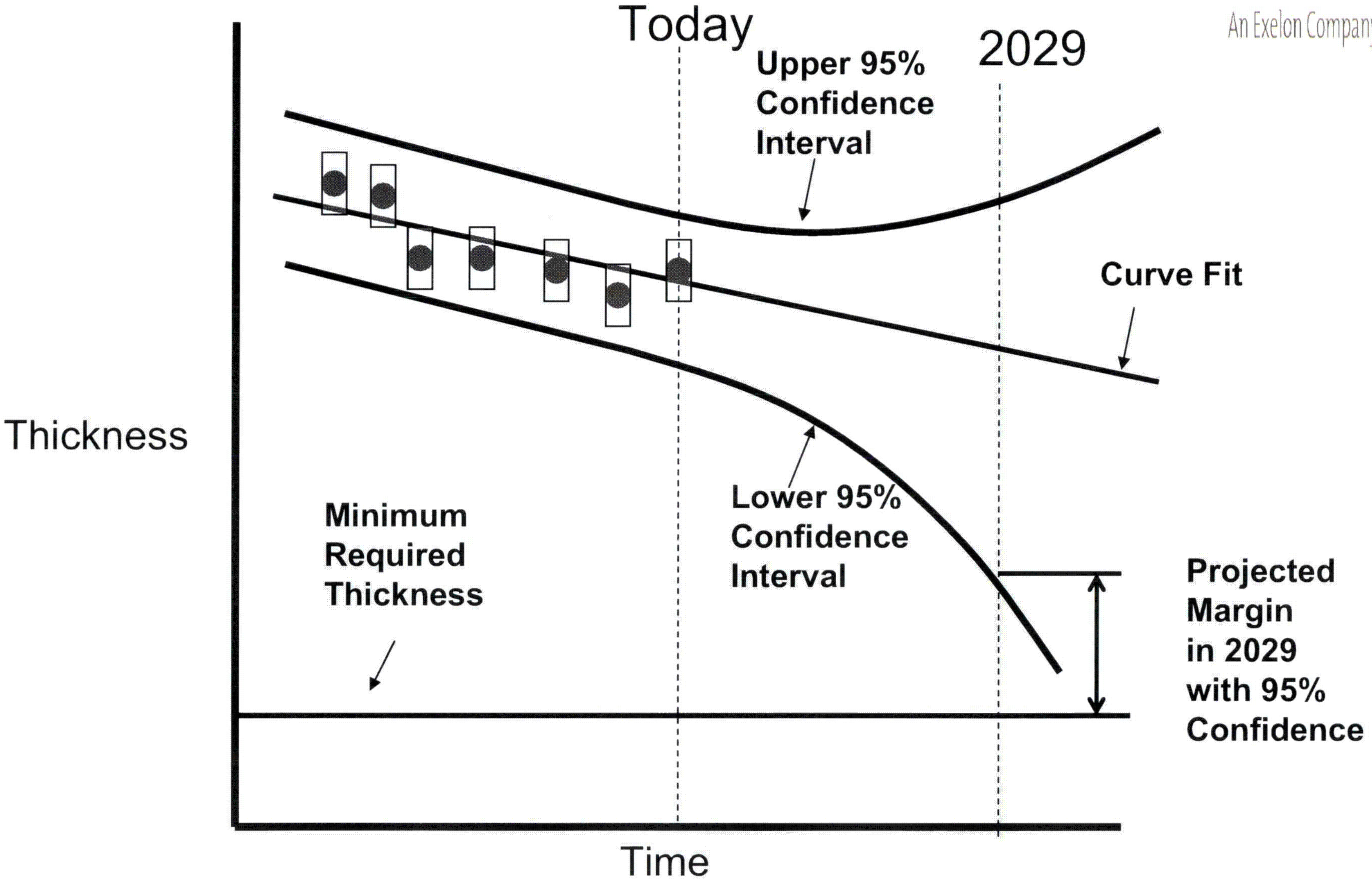

# 2006 Sand Bed Data Summary

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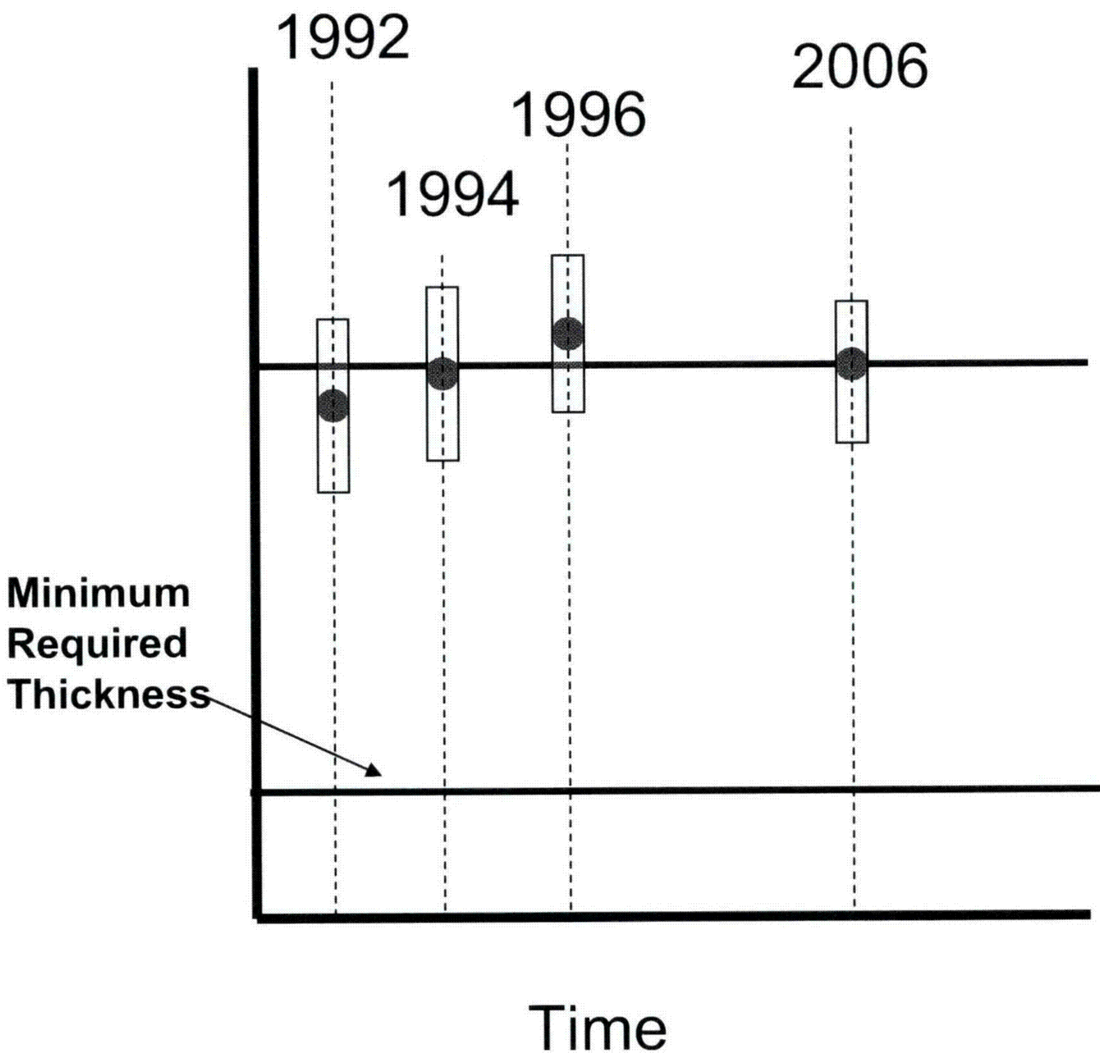


**In the case of the 2006 sand bed inspections, there are only 4 inspections per location with most standard errors between +/- 8 and +/-16 mils**

**There are not enough inspections to satisfy the Corrosion Test F test with 95% confidence.**

**KEY**

● **- mean value**

▯ **- standard error**

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# Statistical Methodology

- We then employed a conservative statistical analysis based on a "Monte Carlo" type simulation to determine a minimum statistically observable corrosion rate for the purpose of ensuring adequate inspection frequency

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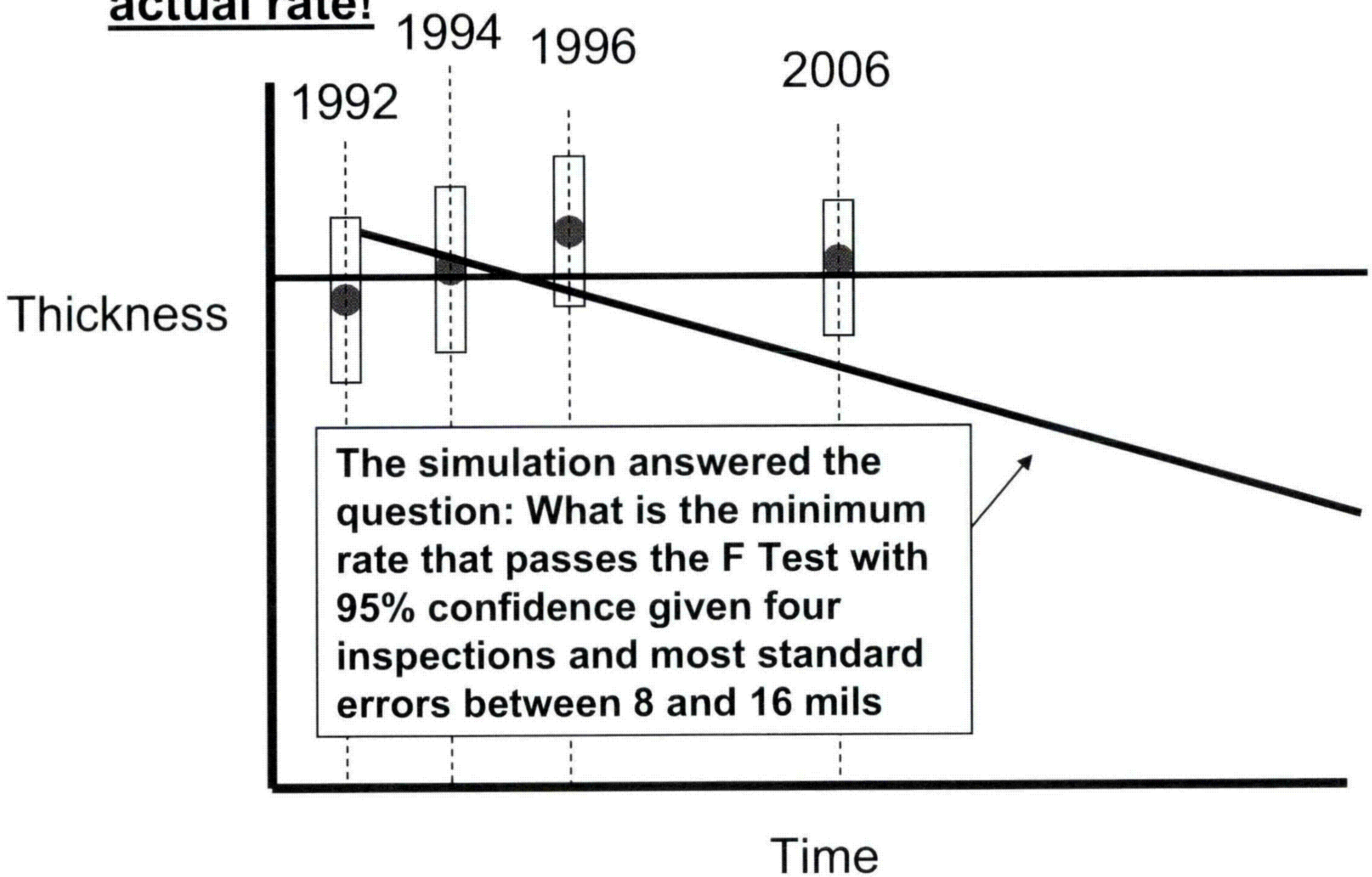
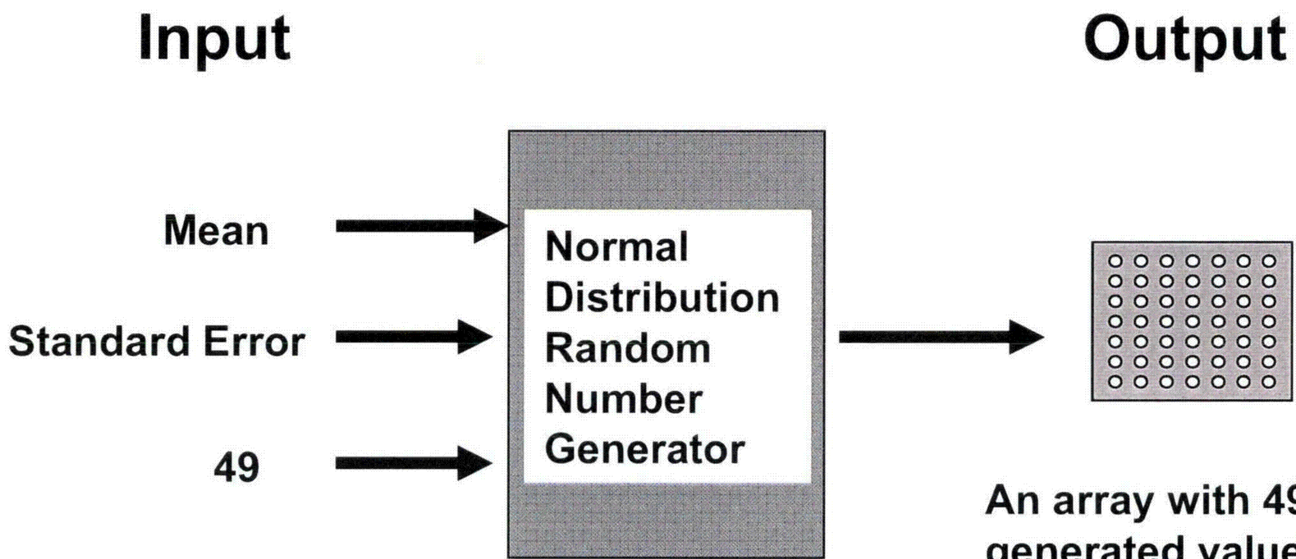
**Given only 4 inspections and the standard errors, simulation was required to determine the minimum observable rate with 95% confidence. <u>This is not an actual rate!</u>**



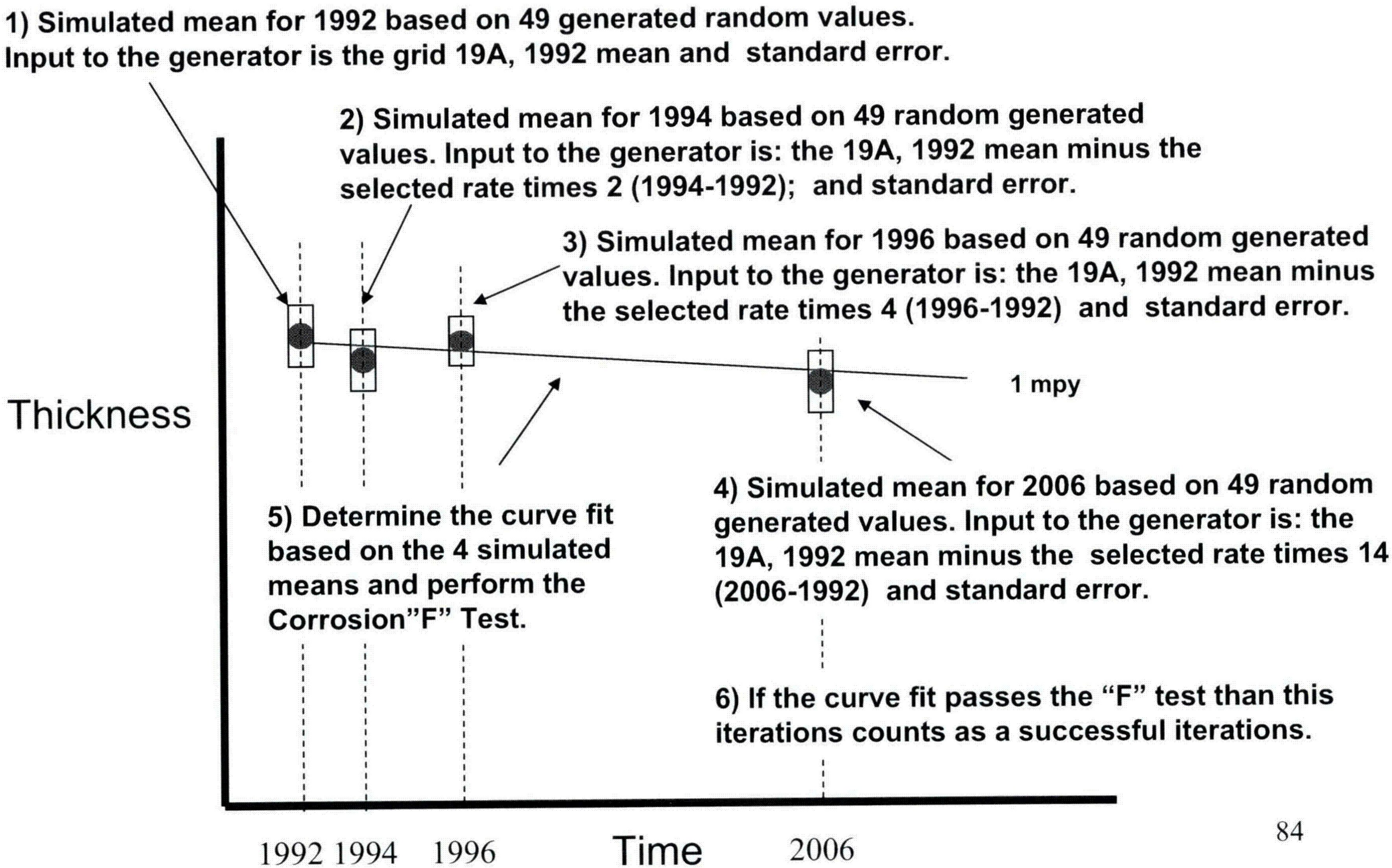
# The simulation used a random number generator based on the normal distribution




An array with 49 randomly generated values. The array is normally distributed with a resulting simulated mean and a resulting simulated standard error.

## Simulation – Minimum Observable Corrosion Rate

### Chose a rate and performed 100 Iterations (Steps 1 through 6)



## Simulation – Minimum Observable Corrosion Rate

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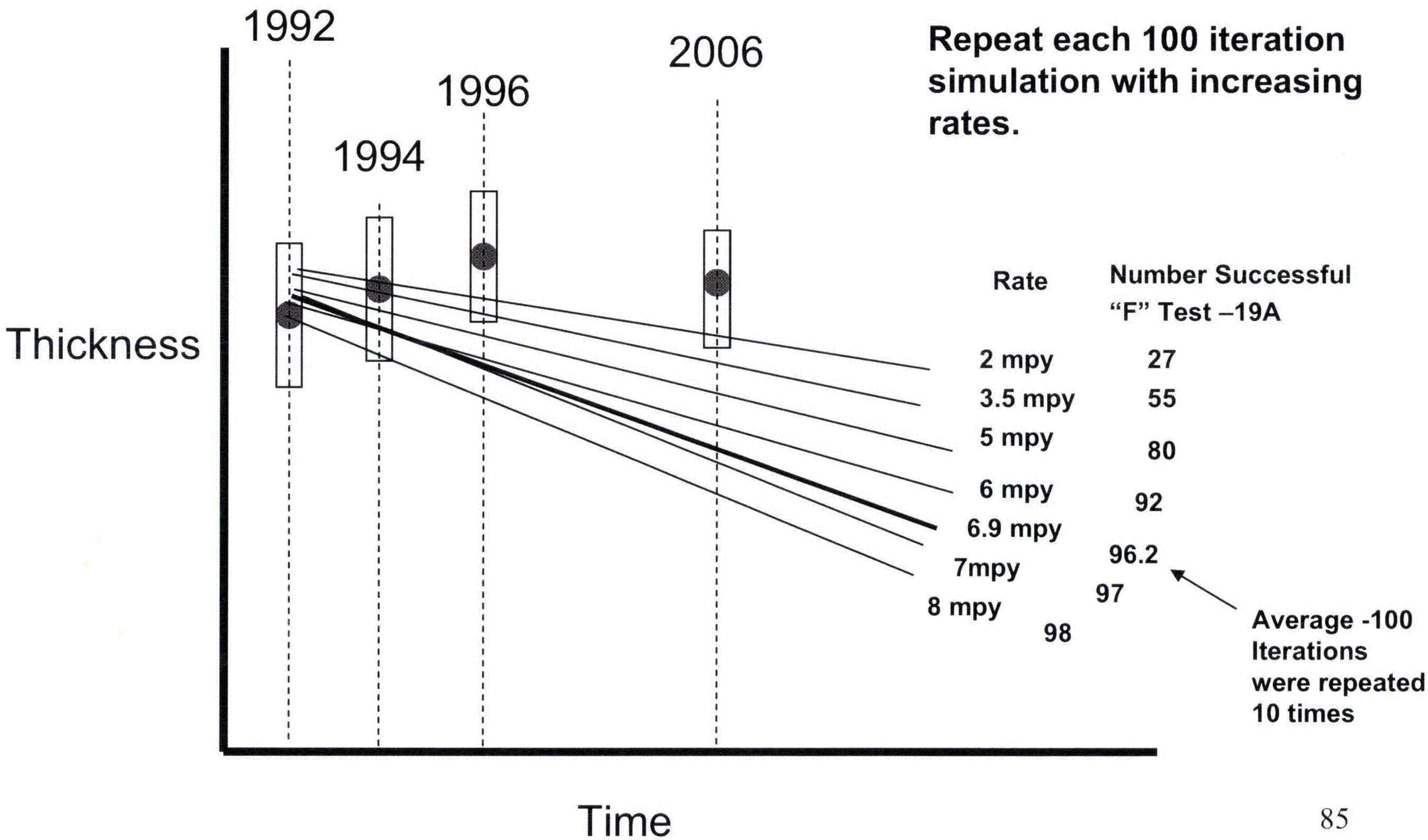
**The minimum rate which consistently passes the Corrosion "F" Tests 95 out of 100 times is the Minimum Observable Corrosion Rate.**




**Repeat each 100 iteration simulation with increasing rates.**

## Next Required Inspection Based on the Minimum Observable Rate

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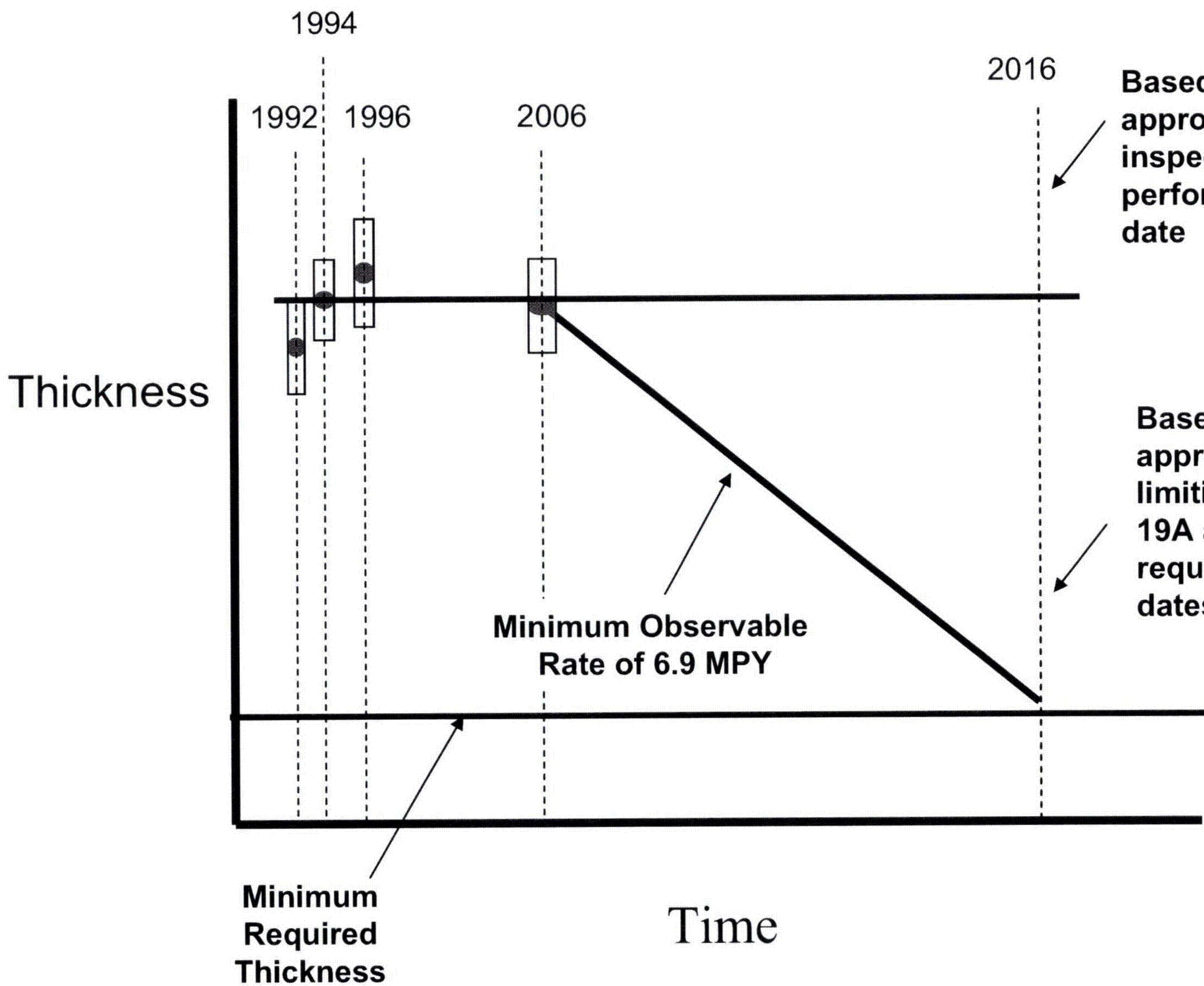


**Based on this statistical approach, the next inspection shall be performed prior to this date**

**Based on this statistical approach the most limiting locations are 19A and 17D with required inspection dates prior to 2016.**

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# Results of the Statistical Simulation

- The most limiting locations are 19A and 17D, with required inspections prior to 2016
- Therefore, the next inspection scheduled for 2010 is appropriate
- Analysis after future inspections will be used to determine the appropriate inspection frequency

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# 2006 Inspections
# Sand Bed Region

- Visual inspection of coating in all 10 bays (external)
- UT measurements of 19 grids at elev. 11'3" (internal)
- UT measurements 106 locally thinned single point locations (external)

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# 2006 Inspection Results
# Sand Bed Region

- Visual inspection of External Shell Coating – no degradation

# Sand Bed Region 2006

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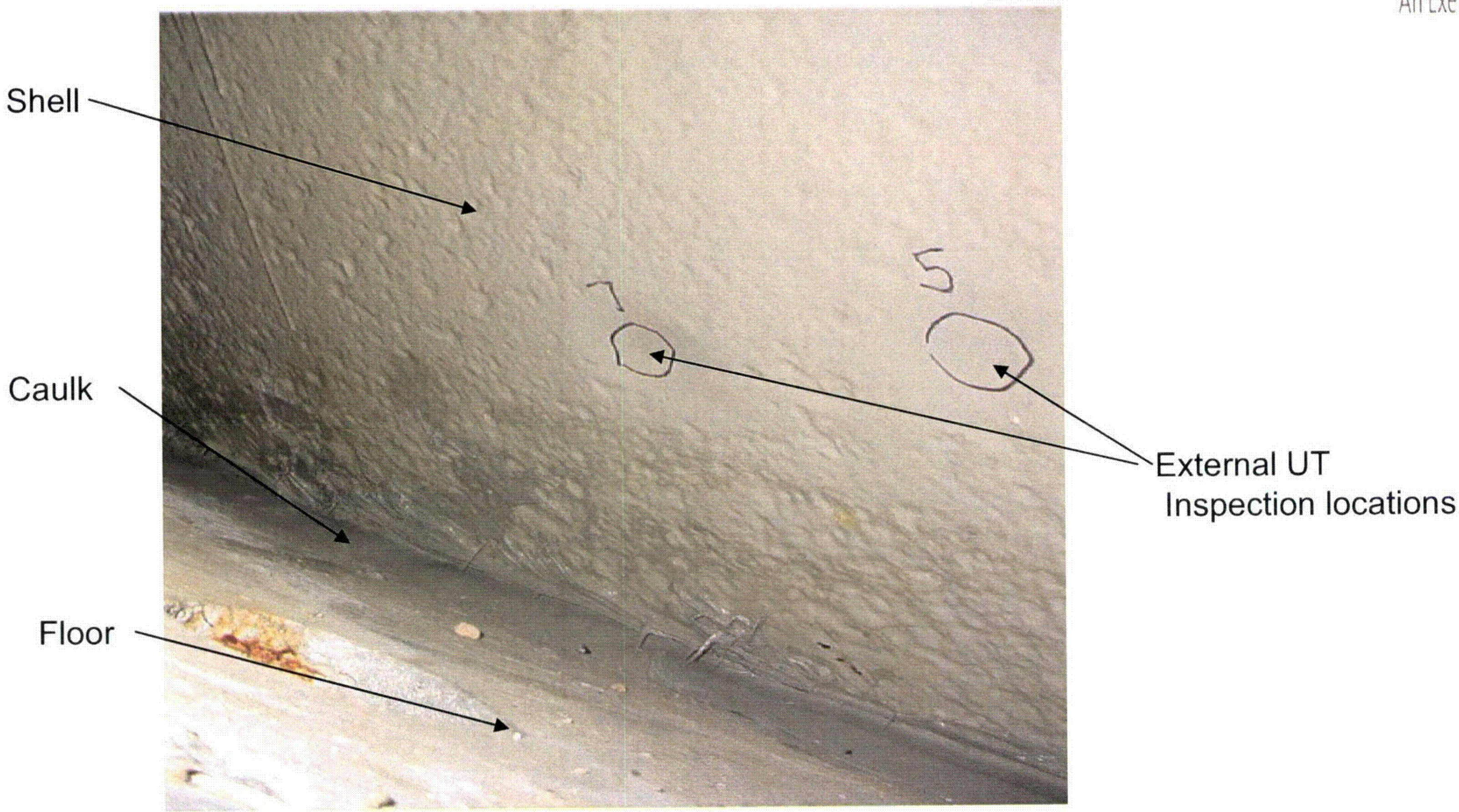


Bay 7 – Drywell shell, caulking, sand bed floor

# Sand Bed Region 2006

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Reference for locating inspection points

External UT Inspection location

Bay 13 Drywell shell

# Sand Bed Region 2006

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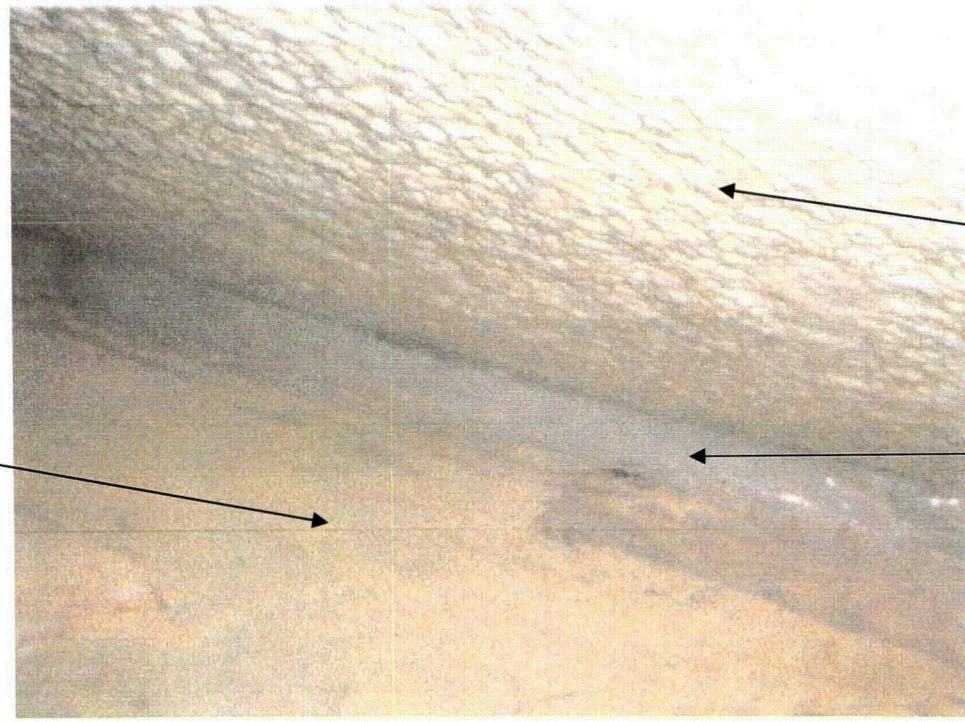


Bay 19 caulking

Drywell Shell Bay 19

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# 2006 Inspection Results

## Sand Bed Region

- UT measurements at 19 internal grid locations
  - No ongoing corrosion

# General Thickness at 19 Grid Locations

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| Location | | Pre-1992 | May 1992 | Sept. 1992 | | 1994 | | 1996 | | 2006 | | Min. Req'd | Nominal Thick. | Margin |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Thick | Std Error | Thick | Std Error | Thick | Std Error | Thick | Std Error | | | |
| 1D | | 1115 | | | | **1101** | ±10.0 | 1151 | ±13.6 | 1122 | ±8.4 | | | 365 |
| 3D | | 1178 | | | | 1184 | ±4.9 | **1175** | ±7.5 | 1180 | ±5.7 | | | 439 |
| 5D | | 1174 | | | | **1168** | ±2.6 | 1173 | ±2.2 | 1185 | ±2 | | | 432 |
| 7D | | 1135 | | | | 1136 | ±4.3 | 1138 | ±5.9 | **1133** | ±6.5 | | | 397 |
| 9A | | 1155 | | | | 1157 | ±4.5 | 1155 | ±4.8 | **1154** | ±4.2 | | | 418 |
| 9D | | 992 | 1000 | 1004 | ±10.0 | **992** | ±10.4 | 1008 | ±10.6 | 993 | ±11.2 | | | 256 |
| 11A | | 833 | 842 | 825 | ±8.2 | **820** | ±7.7 | 830 | ±8.7 | 822 | ±8.0 | | | 84 |
| 11C | Bot | 856 | 882 | 859 | ±6.4 | **850** | ±4.5 | 883 | ±7.4 | 855 | ±4.5 | | | 114 |
| | Top | **952** | 1010 | 970 | ±23.8 | 982 | ±23.4 | 1042 | ±21.4 | 958 | ±24.7 | | | 216 |
| 13A | | 849 | 865 | 858 | ±9.6 | **837** | ±7.8 | 853 | ±8.8 | 846 | ±8.2 | | | 101 |
| 13D | Bot | 900 | 931 | 906 | ±9.0 | **895** | ±8.2 | 933 | ±9.6 | 904 | ±8.9 | | | 159 |
| | Top | 1048 | 1088 | 1055 | ±14.1 | **1037** | ±13.6 | 1059 | ±11.2 | 1047 | ±13.7 | 736 | 1154 | 301 |
| 13C | | | | 1149 | ±1.9 | **1140** | ±3.8 | 1154 | ±3.2 | 1142 | ±3.1 | | | 404 |
| 15A | | 1120 | | | | **1114** | ±16.3 | 1127 | ±10.8 | 1121 | ±16.6 | | | 378 |
| 15D | | **1042** | 1065 | 1058 | ±8.7 | 1053 | ±9.0 | 1066 | ±8.5 | 1053 | ±8.9 | | | 306 |
| 17A | Bot | **933** | 948 | 941 | ±11.8 | 934 | ±10.7 | 997 | ±10.7 | 935 | ±10.5 | | | 197 |
| | Top | **999** | 1125 | 1125 | ±7.2 | 1129 | ±6.8 | 1144 | ±11.1 | 1122 | ±7.2 | | | 263 |
| 17D | | 822 | 823 | 817 | ±9.2 | **810** | ±9.5 | 848 | ±8.9 | 818 | ±9.5 | | | 74 |
| 17/19 | Top | **954** | 972 | 976 | ±4.8 | 963 | ±4.9 | 967 | ±6.0 | 964 | ±4.8 | | | 218 |
| Frame | Bot | **955** | 990 | 989 | ±6.3 | 975 | ±7.8 | 991 | ±6.2 | 972 | ±5.9 | | | 219 |
| 19A | | 803 | 809 | **800** | ±8.4 | 806 | ±9.9 | 815 | ±9.6 | 807 | ±8.9 | | | 64 |
| 19B | | 826 | 847 | 840 | ±8.7 | **824** | ±7.8 | 837 | ±9.5 | 848 | ±8.6 | | | 88 |
| 19C | | 822 | 832 | **819** | ±11.0 | 820 | ±10.5 | 854 | ±11.8 | 824 | ±11.3 | | | 83 |



Note: Shaded cells indicate thickness value used to conservatively calculate the margin

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# Minimum Available Thickness Margins

| Bay No. | 1 | 3 | 5 | 7 | 9 | 11 | 13 | 15 | 17 | 19 |
|---|---|---|---|---|---|---|---|---|---|---|
| Minimum Available Margin, mils | 365 | 439 | 432 | 397 | 256 | 84 | 101 | 306 | 74 | 64 |

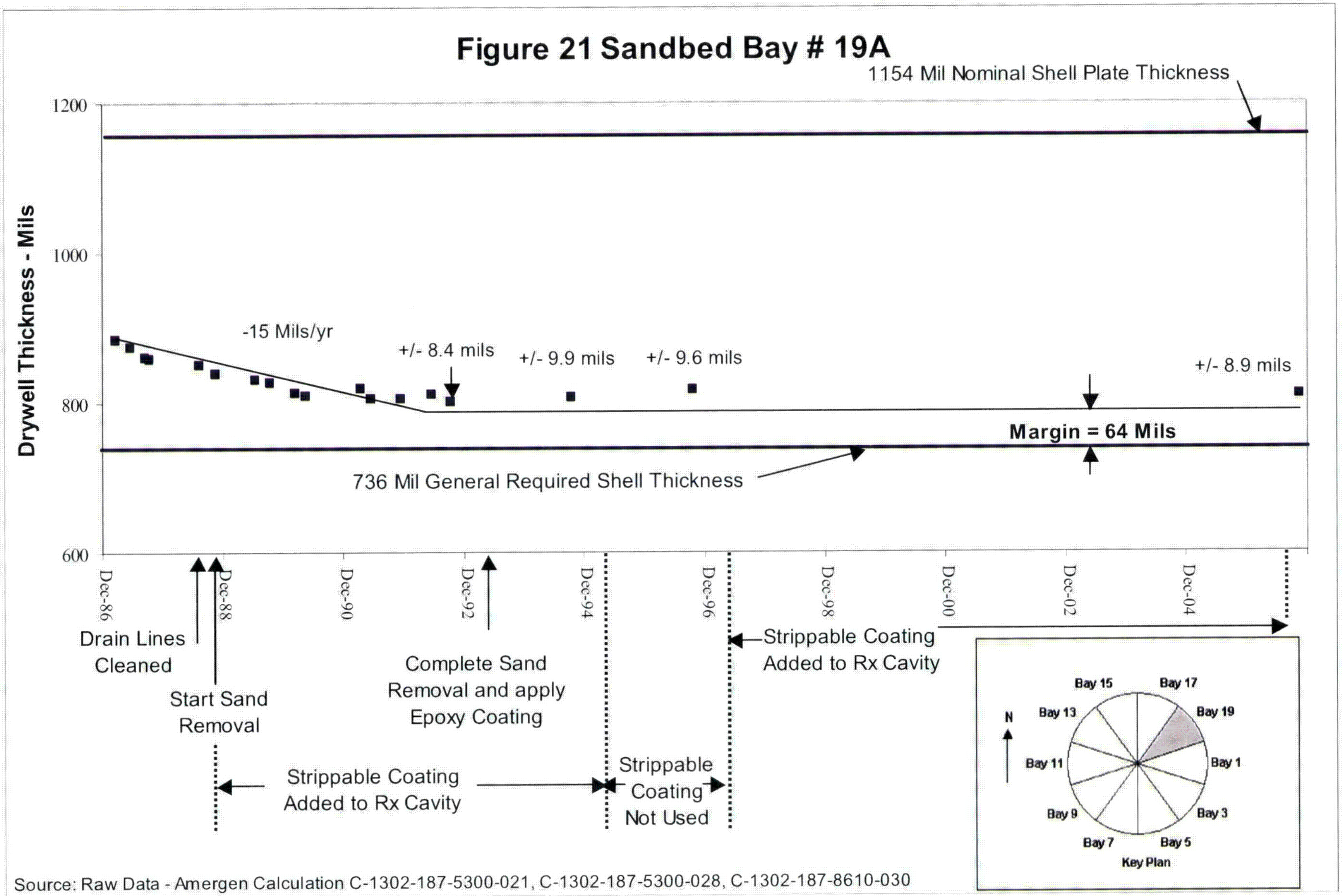
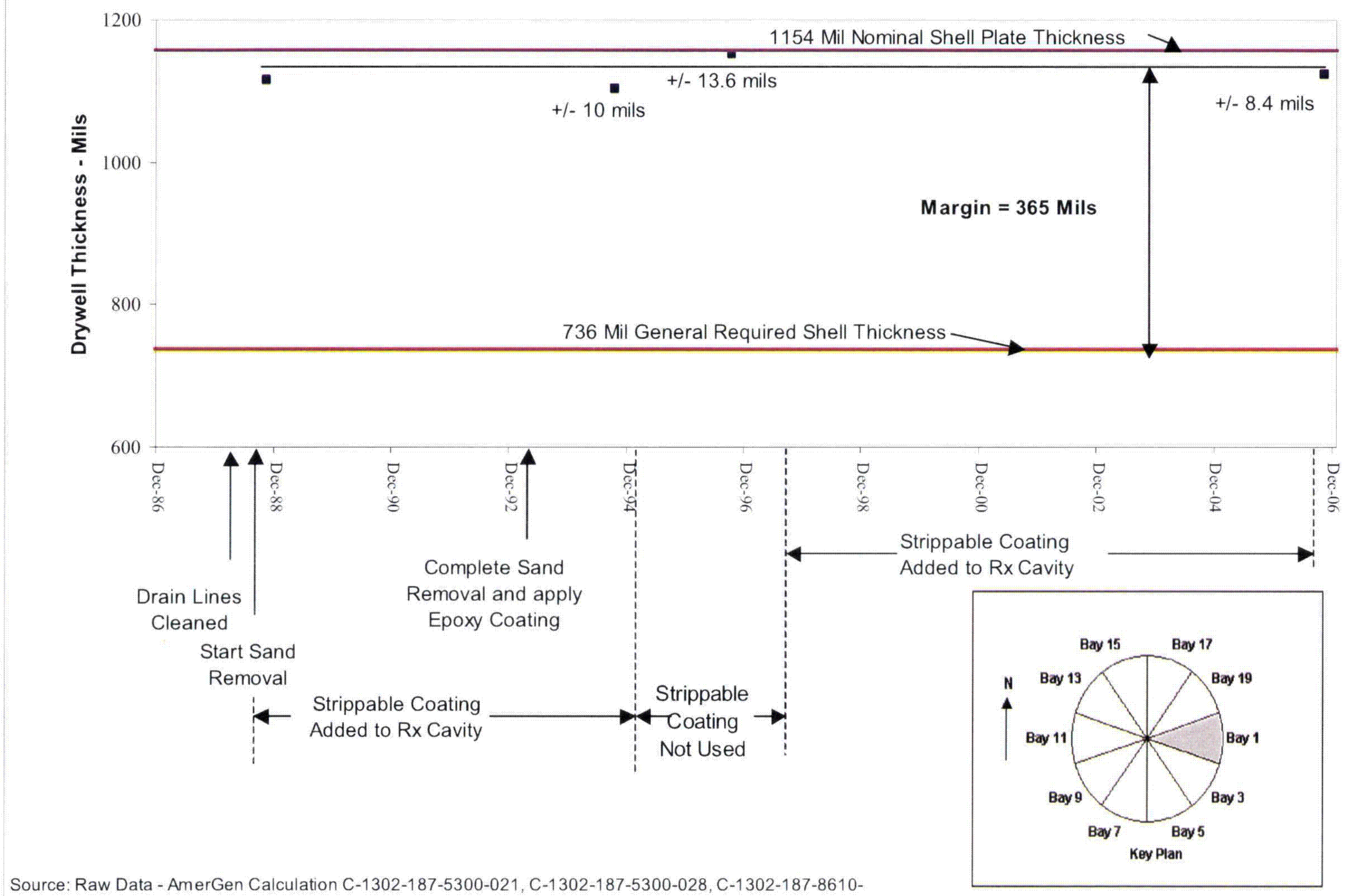


Figure 21 Sandbed Bay # 19A
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
-15 Mils/yr
+/- 8.4 mils
+/- 9.9 mils
+/- 9.6 mils
+/- 8.9 mils
Margin = 64 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Drain Lines Cleaned
Start Sand Removal
Complete Sand Removal and apply Epoxy Coating
Strippable Coating Added to Rx Cavity
Strippable Coating Not Used
Strippable Coating Added to Rx Cavity
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

# Figure 1. Sandbed Bay # 1D




Source: Raw Data - AmerGen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-

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# 2006 Inspection Results External Sand Bed UTs

- 106 individual UT measurements were taken externally in the sand bed region
- It was verified that all 106 measurements meet the local thickness requirements (both buckling and membrane stresses)
- The 2006 measurements are not directly comparable to the 1992 results because of differences in measurement techniques

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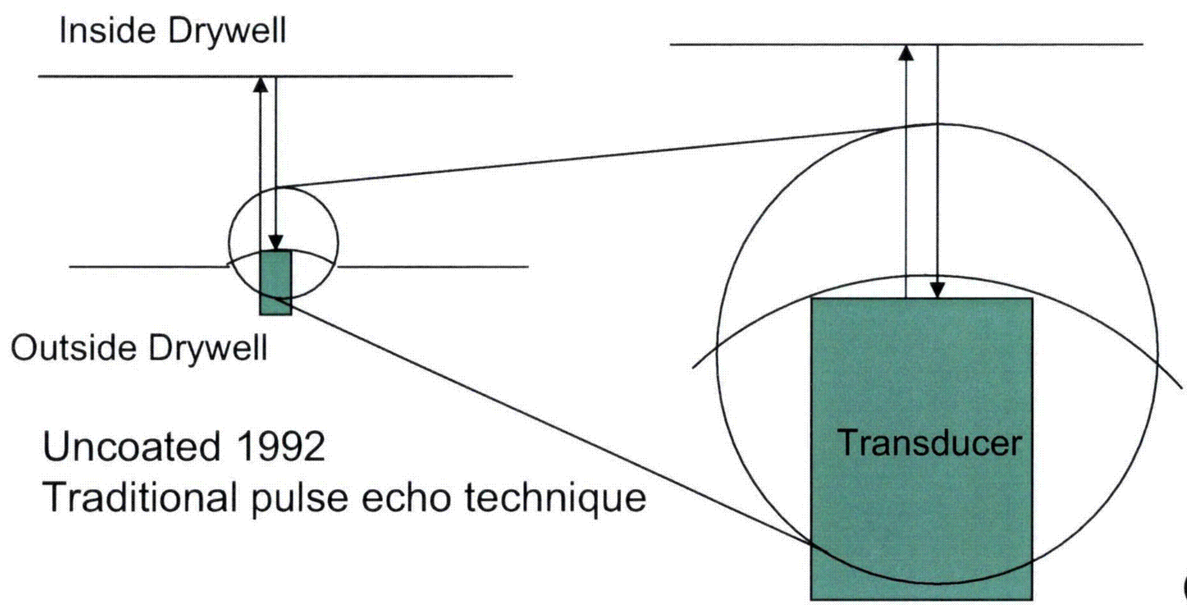
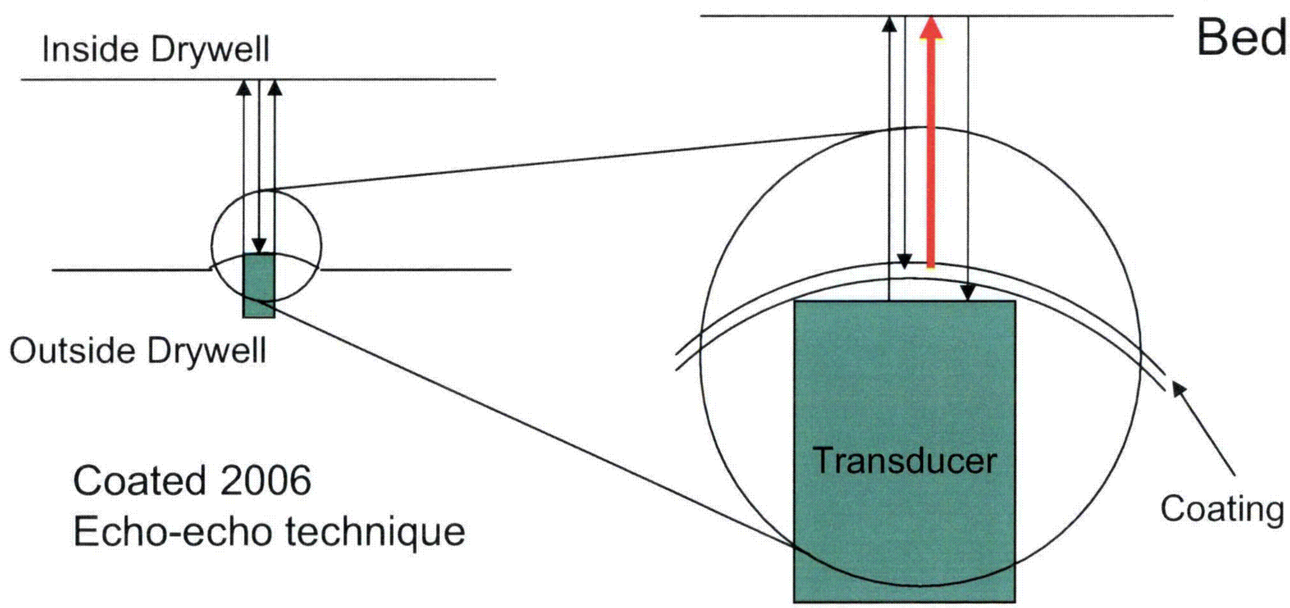
# Concave Curvature Effects 1992 vs. 2006 External UT Data (106) Sand Bed Readings



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# External UT Inspection Results

| Location | 1992 UT Measurements | | | | 2006 UT Measurements | | | |
|---|---|---|---|---|---|---|---|---|
| | No. of UTs | No. of UTs <736 mils | Thickness in mils <736 | Thickness in mils >736 | No. of UTs | No. of UTs <736 mils | Thickness in mils <736 | Thickness in mils >736 |
| Bay 1 | 23 | 9 | 680 to 726 | 760 to 1156 | 23 | 10 | 665 to 731 | 738 to 1160 |
| Bay 3 | 8 | 0 | | 780 to 1000 | 8 | 0 | | 764 to 999 |
| Bay 5 | 8 | 0 | | 890 to 1060 | 7 | 0 | | 880 to 1007 |
| Bay 7 | 7 | 0 | | 920 to 1045 | 5 | 0 | | 964 to 1040 |
| Bay 9 | 10 | 0 | | 791 to 1020 | 10 | 0 | | 781 to 1016 |
| Bay 11 | 8 | 1 | 705 | 755 to 850 | 8 | 1 | 700 | 751 to 830 |
| Bay 13 | 29 | 9 | 618 to 728 | 807 to 941 | 15 | 6 | 602 to 708 | 741 to 923 |
| Bay 15 | 11 | 1 | 722 | 770 to 932 | 11 | 0 | | 749 to 935 |
| Bay 17 | 11 | 1 | 720 | 760 to 1150 | 10 | 1 | 681 | 822 to 970 |
| Bay 19 | 10 | 0 | | 776 to 969 | 9 | 0 | | 738 to 932 |
| Total | 125 | 21 | | | 106[1] | 18 | | |

[1]The locally thinned areas prepared for UT measurements in 1992 were measured in 2006. However, the inspection team was able to locate only 106 points instead of 125.

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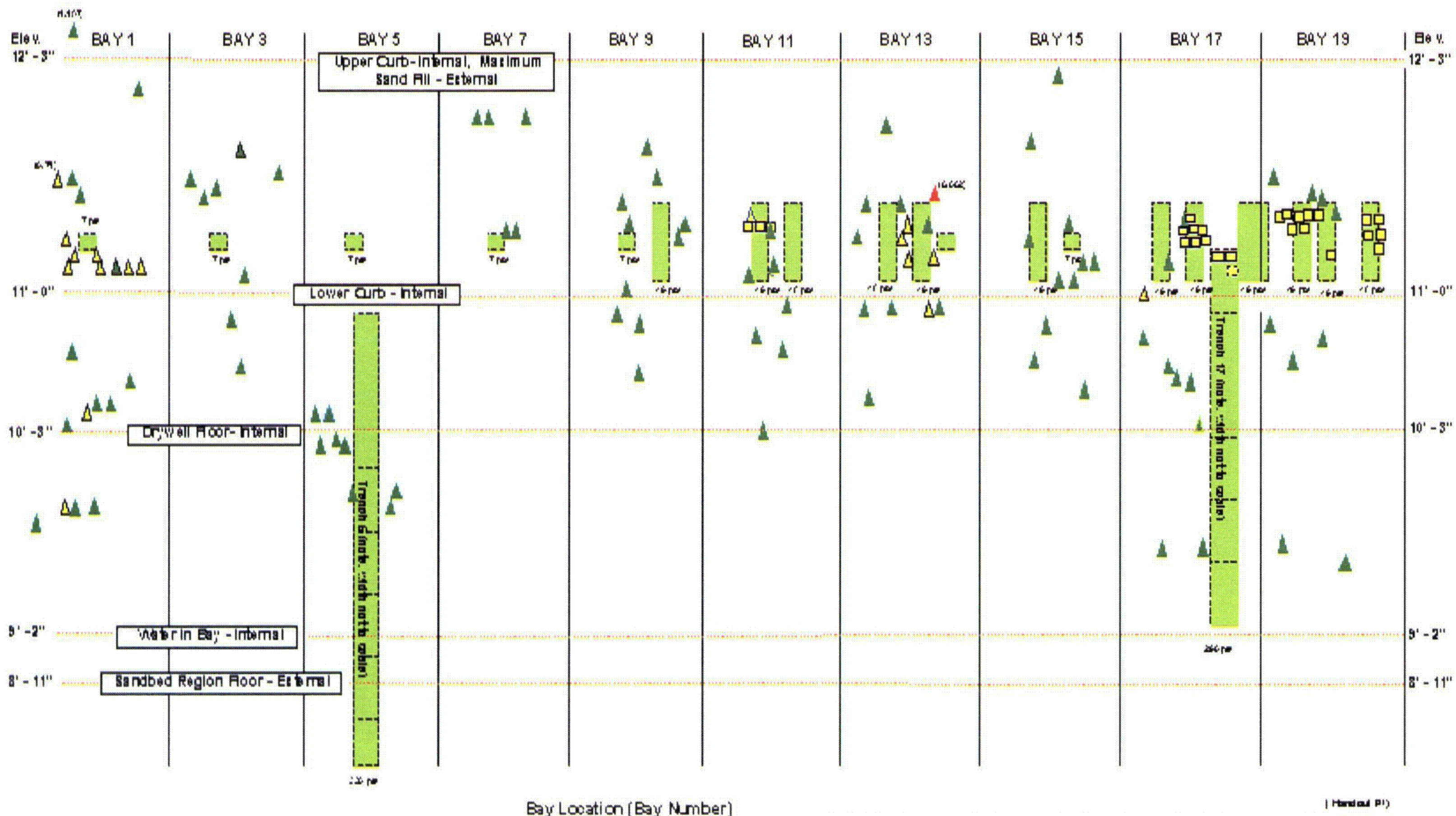
## 2006 Measurement Locations in the Sandbed Region

**Color Code for thickness:**
Green = UT Measurements > 736 Mils
Yellow = UT Measurements Between 636 and 736 Mils
Red = UT Measurements Between 536 and 636 Mils

**Location / Type of UT Measurement**
△ External Point UT Measurements
⸬ Internal Grid UT Measurements
□ Internal Point UT Measurements




(Handout P1)

For illustration of measurement locations in each bay. Vertical dimensions to scale showing approximate measurement locations. Horizontal dimensions not to scale for the individual bays.

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# Sand Bed Region Conclusions

- Corrosion on the outside of the drywell shell in the sand bed region has been arrested
- The coating shows no degradation
- There is sufficient margin to the minimum thickness requirement (maintain 64 mils margin above code required average thickness of 736 mils)

# Future Inspections in the Sand Bed Region

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- Visual inspection of exterior coating in three bays every other outage, inspecting all 10 bays once every 10 years
- UT measurements at 19 grid locations at elev. 11’3” in 2010, then every 10 years thereafter
- Repeat UT at 106 locally thinned locations from the exterior in 2008 outage
  - In future outages, perform UT in 2 bays every outage

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# Embedded Portions of the Drywell Shell

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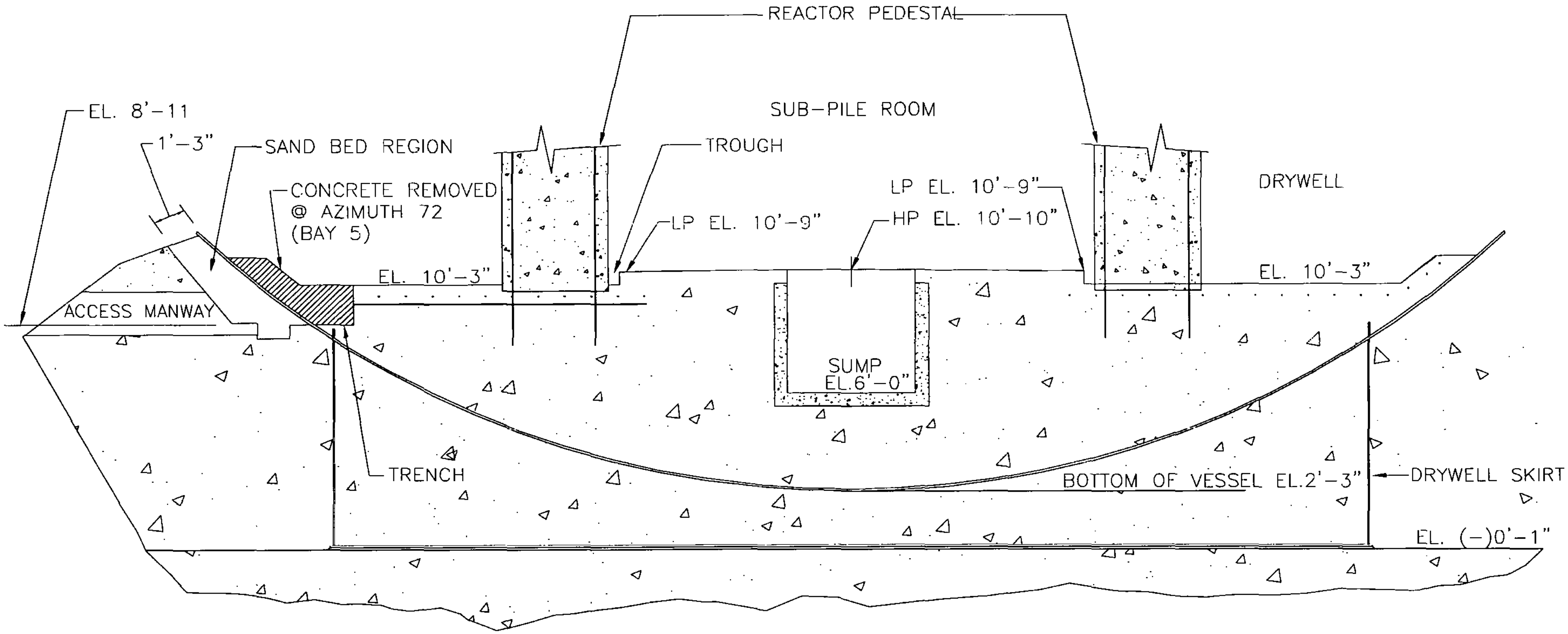
# Embedded Shell Conclusions

- Corrosion on the embedded surfaces of the drywell shell, both interior and exterior, is not significant
  - The environment of embedded steel in concrete prevents significant corrosion
- Estimated at <1 mil / year
- Drywell shell meets design basis requirements, with margin to 2029

# LOWER DRYWELL-
# SANDBED, TRENCH & SUMP




ELEVATION LOOKING WEST

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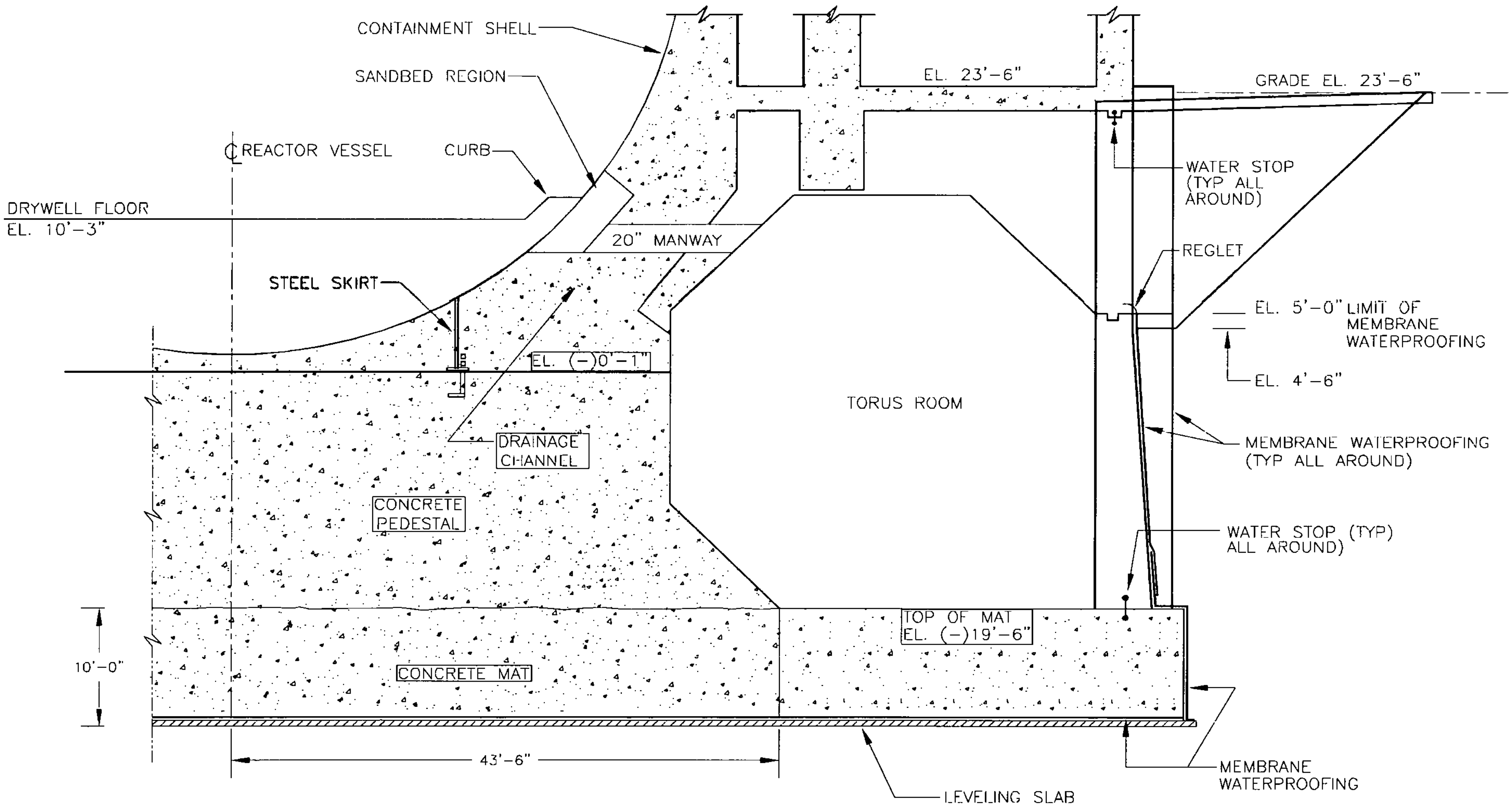
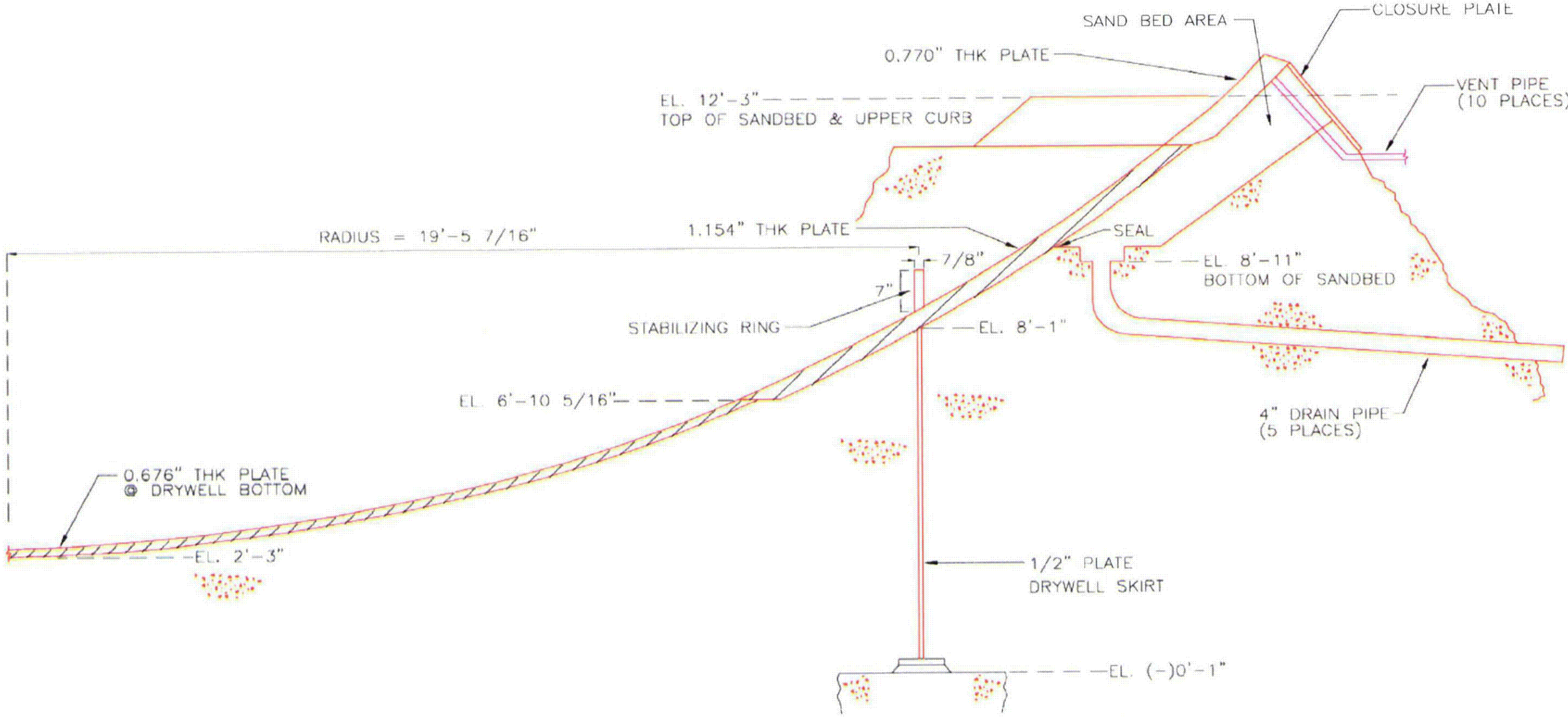
# REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE






SECTIONAL VIEW OF SAND BED AREA
AT VENT PIPE

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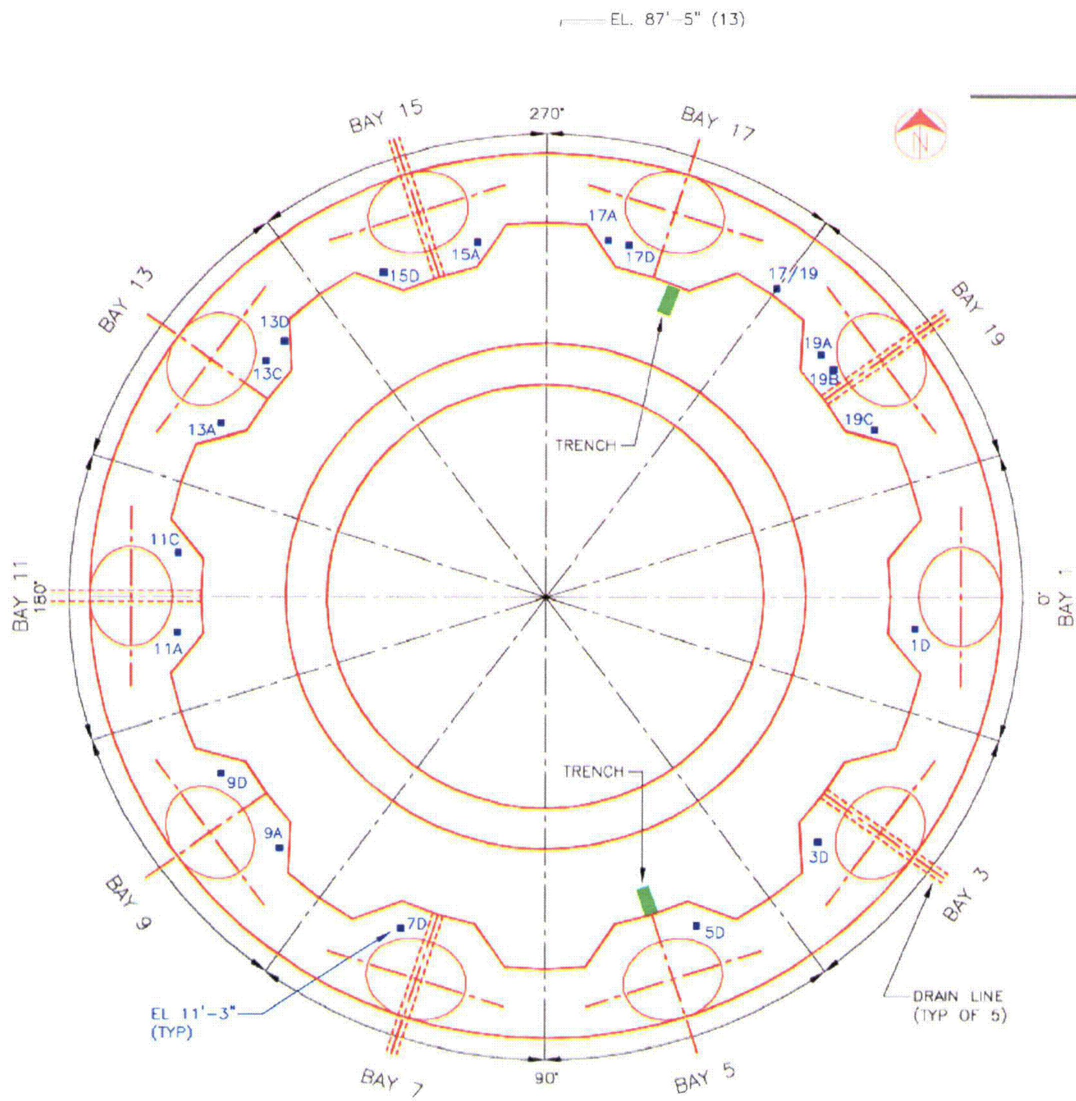


KEY PLAN

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# Embedded Shell – Exterior Surface

- Any corrosion of the drywell exterior embedded surface occurred because of water leakage into the sand bed region
- Corrective actions for the sand bed region arrested corrosion of the drywell exterior embedded shell
  - Water leakage into the sand bed region was prevented
  - The joint between the drywell shell and floor of the sand bed region was sealed to prevent water from contacting the exterior shell

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# Embedded Shell – Interior Surface

- Water that was identified in the trenches in bays 5 and 17 inside the drywell when the foam filling was removed during the 2006 refueling outage was determined to have originated from equipment leakage inside the drywell (Not from external sources)

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# Embedded Shell - Interior Surface

- Investigations into the source of the water indicate that there could have been water below the drywell interior floor for an extended period
- Additional concrete was removed from the bottom of the bay 5 trench to expose 6 inches of drywell shell that was embedded on both sides for UT thickness measurements of the drywell shell

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# Embedded Shell – Interior Surface

- Corrective actions during the 2006 refueling outage included
  - Caulking the joint between the drywell interior floor and the drywell shell
  - Repairs to the collection trough in the sub-pile room

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# Corrosion of Steel Embedded in Concrete

Barry Gordon

Structural Integrity Associates, Inc.

# Corrosion of Steel Embedded in Concrete

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- Drywell shell was constructed first, followed by pouring of concrete both on the inside and the outside of the shell
- The high pH (e.g., 12.5 to 14) environment created during hydration of the cement in the concrete results in the formation of a passive, protective film [$Fe(OH)_2$ + $Ca(OH)_2$] on the carbon steel surface that mitigates corrosion in the absence of an aggressive environment

# Exterior Embedded Steel Environment

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- The reactor cavity water that flowed into the embedded region outside the drywell was affected by the sand bed
- However, the chemistry of the water leachate from moist sand from the sand bed region was measured in 1986 revealed high purity water:
  - pH >7, <0.045 ppm $Cl^-$ <0.032 ppm $SO_4^{=}$
    (US Water: 59 ppm $Cl^-$, 81 ppm $SO_4^{=}$)
  - This water is not aggressive to the embedded steel in concrete per GALL/EPRI

# Exterior Embedded Steel Environment

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- The water in the embedded region would have been the same quality as in the sand bed region, except the pH would have been greater because of the interaction with high pH concrete pore water
- Per GALL NUREG-1801 Vol. 2, Rev.1 and EPRI 1002950, no aging effects are expected since pH>5.5, <500 ppm $Cl^-$ and <1500 ppm $SO_4^=$ (GALL II.B1.2-2, II.B1.2-8)

# Interior Embedded Steel Environment

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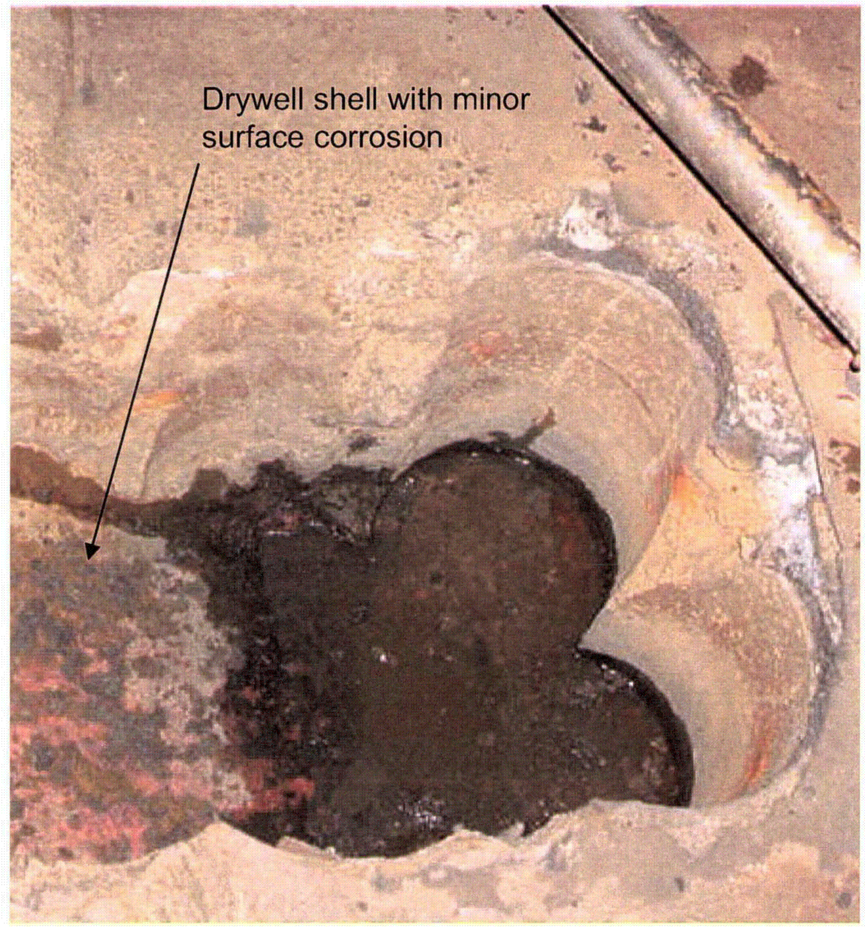
- Chemistry of the drywell Trench #5 water (from equipment leakage) shows high pH, low $Cl^-$, low $SO_4^=$ and high Ca:
  - pH 8.4 to 10.2 (despite $CO_2$) (> GALL/EPRI limit)
  - $Cl^-$: 13.6 – 14.6 ppm (<< 500 ppm GALL/EPRI limit)
  - $SO_4^=$: 228 - 230 ppm (<<1500 ppm GALL/EPRI limit)
  - Ca: 83.5 – 96.6 ppm (No GALL/EPRI limit)
- Water is characterized as good quality "concrete pore water" that mitigates steel corrosion
- Trench #5 water complies with GALL/EPRI embedded steel guidelines

# Interior Embedded Steel Environment

- Trench #5 water's high Ca indicates that the water slowly migrated through the alkaline concrete
- Any subsequent water ingress into the concrete floor will also become high pH concrete pore water



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# Interior Embedded Steel Environment

- Corrosion of the steel shell not wetted by high pH concrete pore water is mitigated by subsequent inerting of the drywell during operation
- Any possible subsequent steel corrosion could occur only during brief outages when fresh oxygenated water can contact with the shell
- Finally, transport of any oxygenated water through the concrete to the steel is slow, will increase in pH and must displace oxygen depleted water before any possible corrosion can occur

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# 2006 Outage Inspections
## Embedded Shell

- Visual inspection of the surface in the trenches showed minor corrosion which was easily removed with no visible loss of material or degradation of the surface

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# 2006 Outage Inspections
## Embedded Shell

- UT measurements in the trenches measure total corrosion on the inside and outside between 1986 and 2006
  - Corrosion was occurring on the exterior surface that was not embedded until 1992 when sand was removed
  - Material loss was consistent with the corrosion rates on the outside of the drywell before the sand was removed

# 2006 Inspection Results Embedded Shell

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## UT measurements in trenches 5 and 17

| | 1986 Thickness | 1986 Std. Error | 2006 Thickness | 2006 Std. Error | Difference |
|---|---|---|---|---|---|
| Trench 5 | 1112 mils | ±2.59 mils | 1074 mils | ±2.66 mils | 38 mils |
| Trench 17 | 1024 mils | ±2.85 mils | 986 mils | ±4.18 mils | 38 mils |

# 2006 Inspection Results
# Embedded Shell

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- UT measurements of the 6 inch surface excavated in the bottom of the trench in bay 5 were performed to determine total corrosion, both interior and exterior
- Measured thickness is 1113 mils, as compared to a nominal of 1154 mils
  - A change of 41 mils, approximately 1 mil/yr

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# 2006 Outage Inspections Embedded Shell

- The 106 individual UT measurements made from the exterior of the sand bed region are a baseline for monitoring corrosion of the interior embedded surface of the drywell in future outages

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# 2006 Inspection Results
# Embedded Shell

- The joint sealant between the sand bed floor and the exterior drywell shell was inspected and found to be in good condition
- No water was identified in the sand bed region in any of the 10 bays

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# Embedded Shell Conclusions

- Corrosion on the embedded surfaces of the drywell shell, both interior and exterior, is not significant
  - The environment of embedded steel in concrete prevents significant corrosion
- Estimated at <1 mil / year
- Drywell shell meets code thickness requirements, with margin to 2029

# Future Inspections on the Embedded Shell

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- Repeat UT measurements in both trenches, including the newly excavated 6 inches in 2008
  - If results indicate no significant changes, then fill the trenches with concrete and restore the curb to original configuration
- Repeat UT measurements at 106 external points in 2008
  - Perform external UT measurements in 2 bays every refuel outage starting in 2010
  - All bays will be inspected every 10 years

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# Upper Drywell Shell

# Upper Drywell Shell Conclusions

- These measurements are the lead indicators of corrosion on the outside of the shell
- Corrosion of the upper shell is <1 mil / yr
- Upper Drywell shell has a minimum of 137 mils margin
- Based on current rates, will have margin through the period of extended operation

# Upper Drywell Shell

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- Starting in 1983, over 1,000 UT measurements were taken to locate areas of corrosion on the exterior surface of the drywell shell
- 13 grid locations have been selected for monitoring
- These locations are measured every other refueling outage

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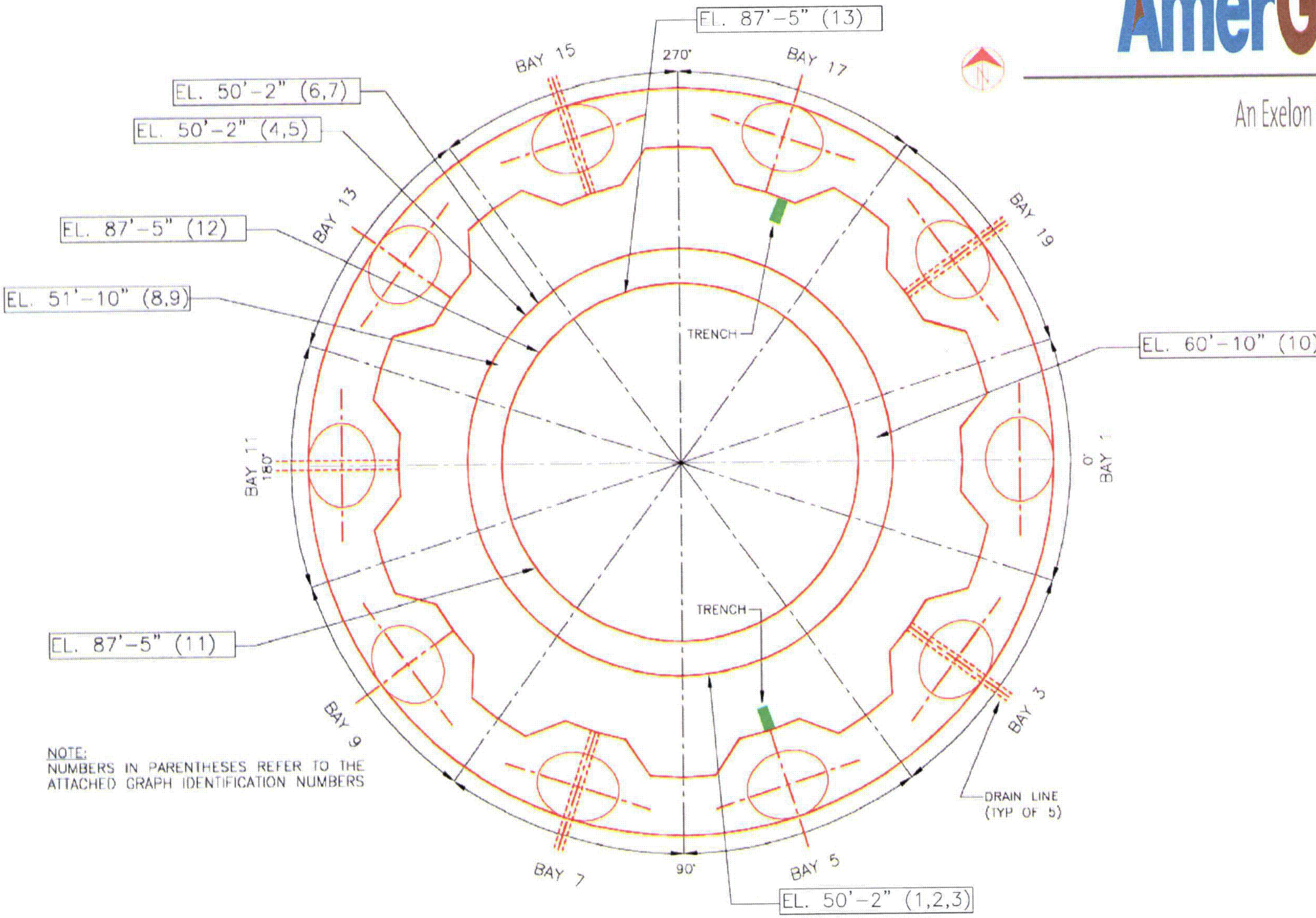


KEY PLAN

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# Upper Drywell UT Measurements

| Monitored Elevation | Location | Minimum Required Thickness<br>mils | Average Measured Thickness [1,2] mils | | | | | | | | | | | | Projected Thickness in 2029<br>mils |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993[3] | 1994 | 1996 | 2000 | 2004 | 2006 | |
| Elevation | | 541 | | | | | | | | | | | | | |
| 50' 2" | Bay 5-D12 | | | | | 743<br>745<br>746 | 742<br>745<br>748 | 747<br>747 | | 741 | 748 | 741 | 743 | 747 | No Observable Ongoing Corrosion |
| | Bay 5-5H | | | | | 761<br>761 | 755<br>758<br>760 | 759<br>759 | | 754 | 757 | 754 | 756 | 760 | No Observable Ongoing Corrosion |
| | Bay 5-5L | | | | | 706<br>703 | 703<br>705<br>706 | 703<br>702 | | 702 | 705 | 706 | 701 | 705 | No Observable Ongoing Corrosion |
| | Bay 13-31H | | | | | 762<br>779 | 760<br>758<br>765 | 765<br>763 | | 759 | 766 | 762 | 758 | 762 | No Observable Ongoing Corrosion |
| | Bay 13-31L | | | | | 687<br>684 | 689<br>678<br>688 | 685<br>688 | | 683 | 690 | 682 | 693 | 678 | No Observable Ongoing Corrosion |
| | Bay 15-23H | | | | | 758<br>764 | 762<br>762<br>765 | 767<br>763 | | 758 | 760 | 758 | 757 | | |
| | Bay 15-23L | | | | | 726<br>728 | 726<br>729<br>725 | 726<br>724 | | 728 | 724 | 729 | 727 | 749 | 720 |

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# Upper Drywell UT Measurements

| Monitored Elevation | Location | Minimum Required Thickness mils[5] | Average Measured Thickness [1,2] mils 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993[3] | 1994 | 1996 | 2000 | 2004 | 2006 | Projected Thickness in 2029 mils |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Elevation 51' 10" | | 518 | | | | | | | | | | | | | |
| | Bay 13-32H | | | | | 716 | 715<br>715<br>720 | 717<br>717 | | 714 | 715 | 715 | 713 | 715 | No Observable Ongoing Corrosion |
| | Bay 13-32L | | | | | 686 | 683<br>683<br>682 | 683<br>676 | | 680 | 684 | 679 | 687 | 685 | No Observable Ongoing Corrosion |
| Elevation 60' 10" | Bay 1-50-22 | 518 | | | | | | | 693 | 711 | 693 | 689 | 693 | 691 | No Observable Ongoing Corrosion |
| Elevation 87' 5" | Bay 9-20 | 452 | 619 | 622<br>620 | 619 | 620 | 614<br>612 | 629<br>614 | | 613 | 613 | 604 | 612 | 617 | No Observable Ongoing Corrosion |
| | Bay 13-28 | | 643 | 641<br>642 | 645 | 643 | 635<br>629 | 641<br>637 | | 640 | 636 | 635 | 640 | 642 | No Observable Ongoing Corrosion |
| | Bay 15-31 | | 638 | 636<br>636 | 638 | 642 | 628<br>627 | 631<br>630 | | 633 | 632 | 628 | 630 | 633 | No Observable Ongoing Corrosion |

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 inspections was performed on January 6, 1993. All other locations were inspected in December 1992.

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# Upper Drywell Shell 2006 Inspection Results

- 12 of the 13 locations show no statistically observable corrosion
- The location with the minimum margin (137 mils) has no ongoing corrosion
- 1 location shows a corrosion rate of 0.66 mils/year
  - Projected thickness in 2029 is 720 mils, compared to a minimum required thickness of 541 mils

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# Upper Drywell Shell Conclusions

- These measurements are the lead indicators of corrosion on the outside of the shell
- Corrosion of the upper shell is <1 mil / yr
- Upper Drywell shell has a minimum of 137 mils margin
- Based on current rates, will have margin through the period of extended operation

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# Overall Conclusions

- The corrective actions to mitigate drywell shell corrosion have been effective
- The drywell shell corrosion has been arrested in the sand bed region and continues to be very low in the upper drywell elevations
- The corrosion on the embedded portion of the drywell shell is not significant
- The drywell shell meets code safety margins
- We have an effective aging management program to ensure continued safe operation

APPLICANT'S EXHIBIT 41

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# Oyster Creek License Renewal Presentation to ACRS

February 1, 2007

# Agenda

- Summary of Drywell Corrosion
- Resolution of Drywell Shell Corrosion Issues from January 18, 2007 Subcommittee Meeting
- License Renewal Application Summary

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# AmerGen Representatives

- Mike Gallagher
- Fred Polaski
- John O'Rourke
- Dr. Hardayal Mehta
- Dr. Clarence Miller
- Ahmed Ouaou

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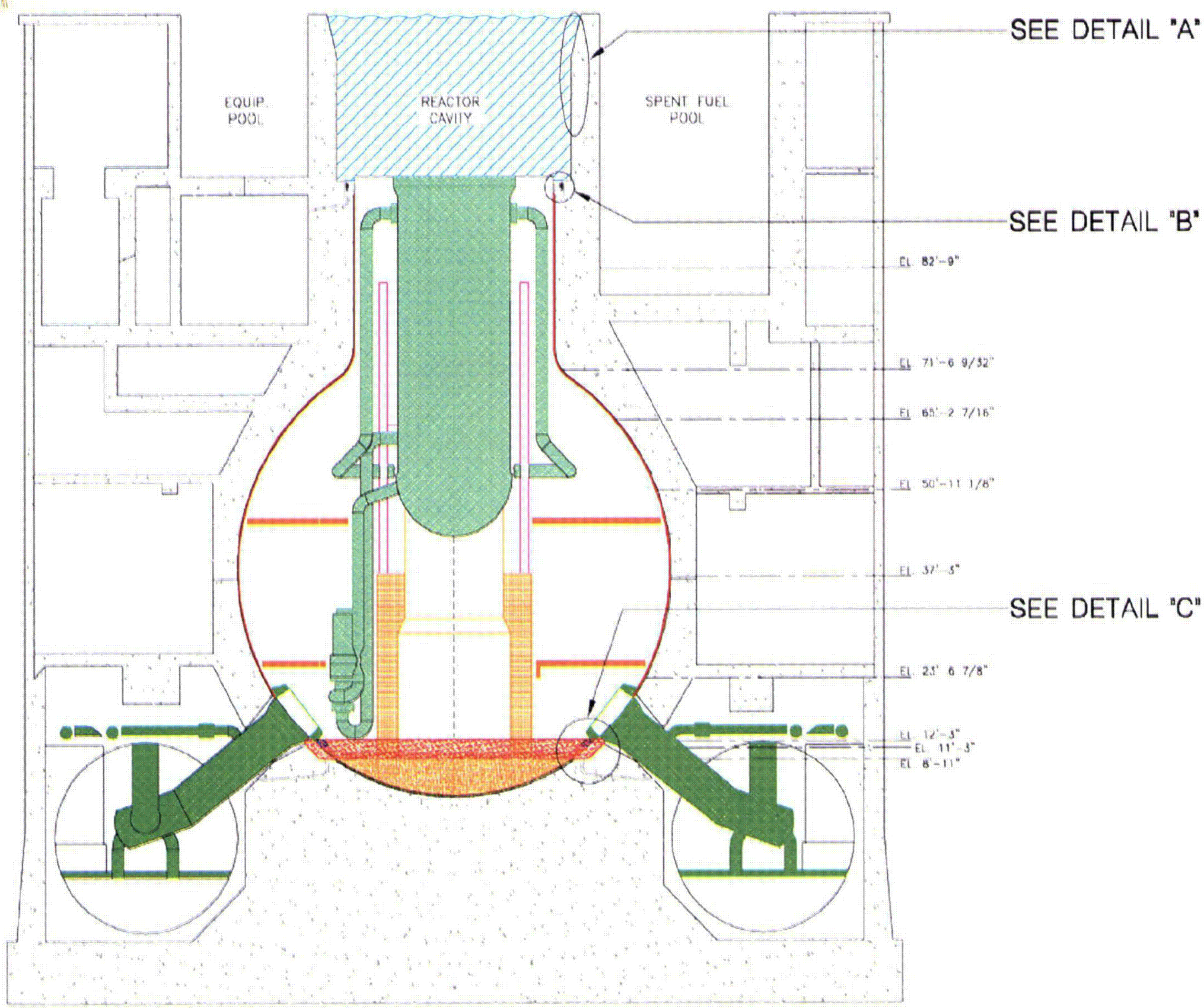

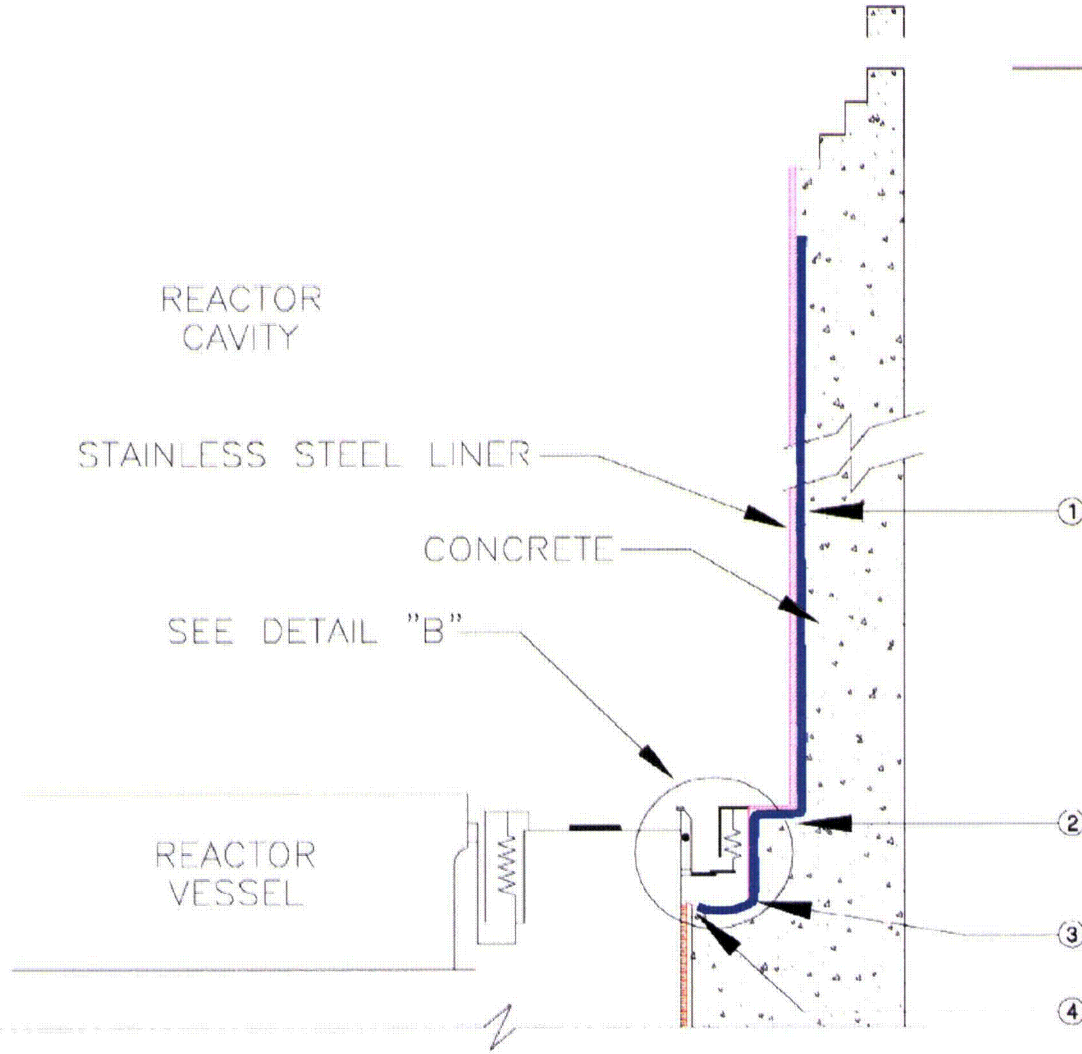


DRYWELL AND REACTOR CAVITY SECTION
DETAIL "A"

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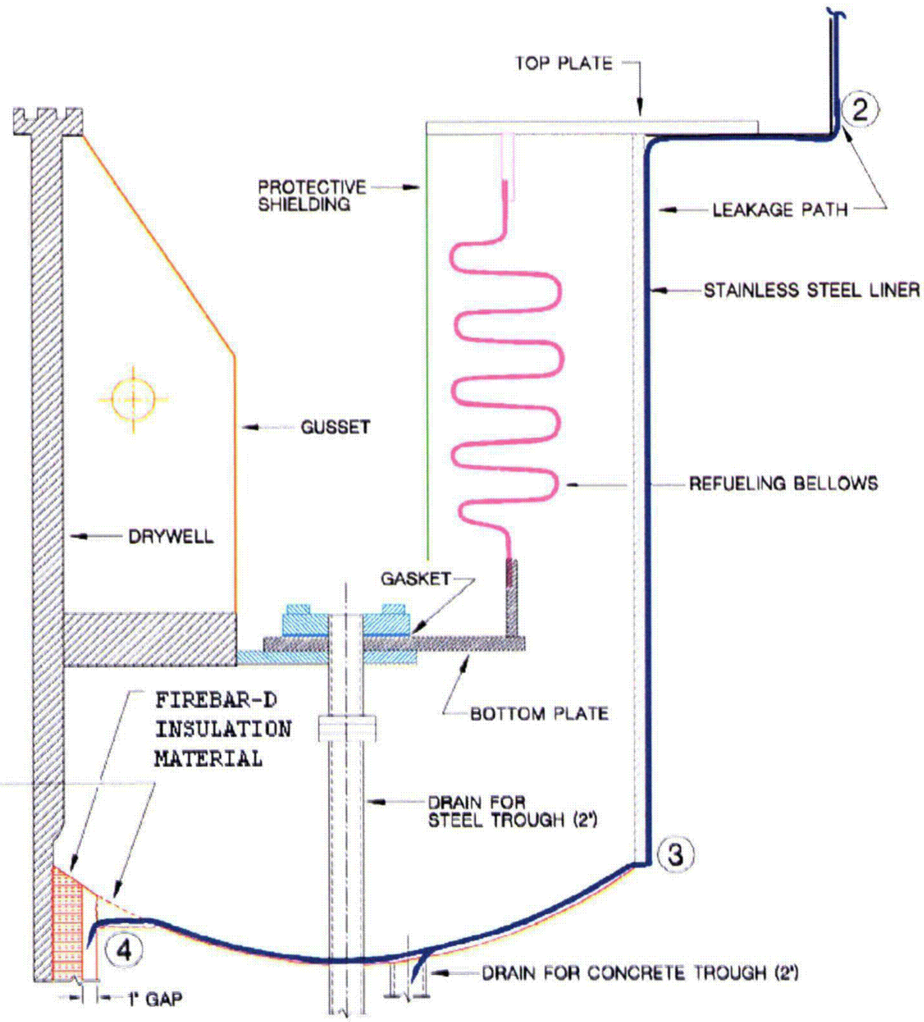
DRYWELL TO REACTOR CAVITY SEAL DETAIL
DETAIL 'B'



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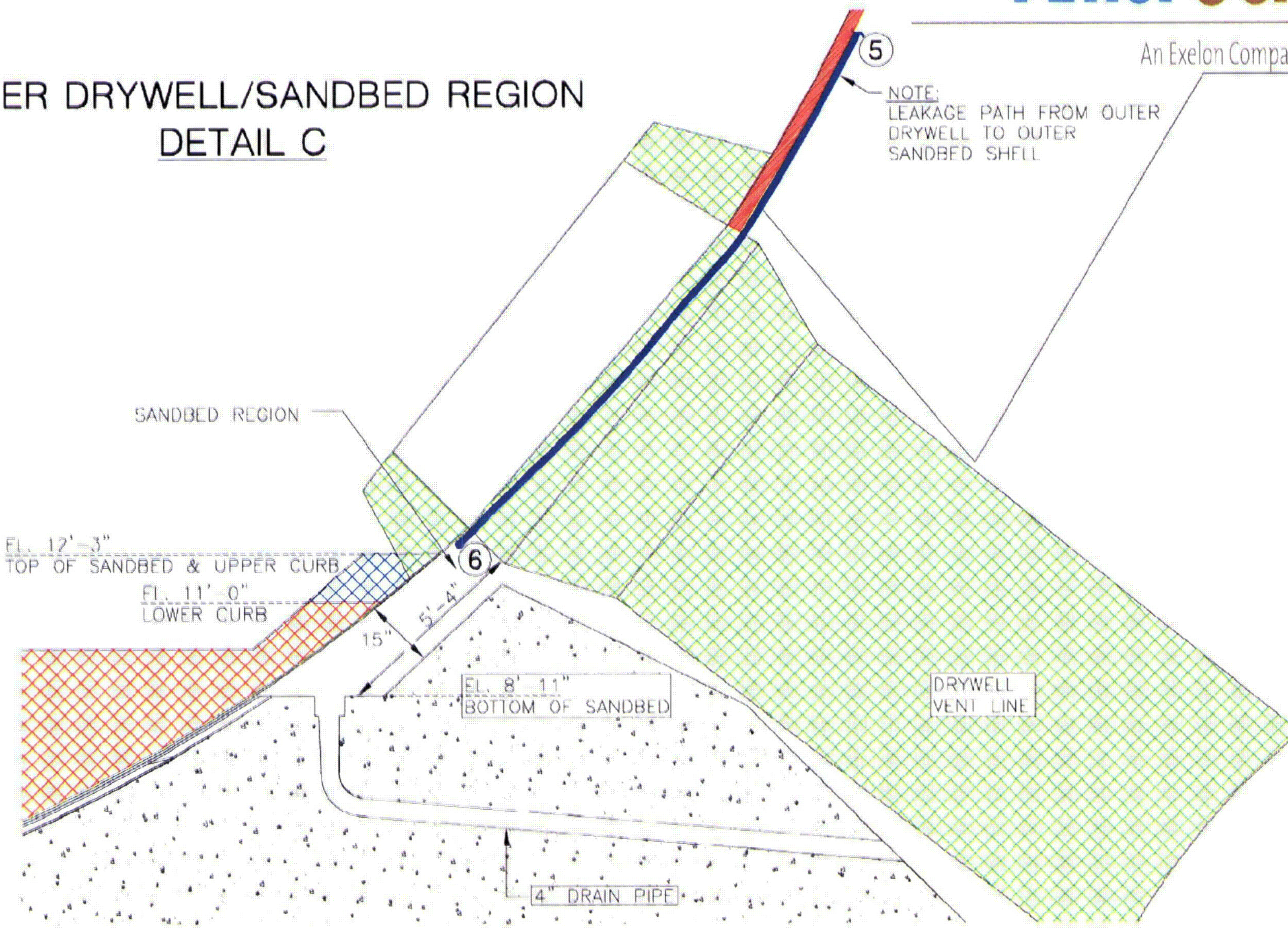
# LOWER DRYWELL/SANDBED REGION
## DETAIL C



# Summary of Drywell Corrosion

- Leakage from the reactor cavity liner accumulated in the sand bed region, corroding the exterior surface of the drywell shell
- Corrective actions
  - Water has been prevented from entering the sand bed region
  - The sand was removed and the exterior of the drywell shell coated with an epoxy coating
  - Analysis performed to determine code required thickness of the drywell shell

# Summary of Drywell Corrosion

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- GE analysis of code required thickness (1992)
  - Buckling analysis based on Code case N-284 for refueling condition with no sand in the sand bed region for a 36° section model with 736 mils uniform thickness and Safety Factor of 2.0
    - 736 mils is the code required general thickness for buckling in the sand bed region
    - Local thickness criteria also established (e.g., 536 mils for a 12" x 12" area)
- A Section VIII analysis for internal pressure was originally performed at a design pressure of 62 psig; later updated for 44 psig design pressure (1993)
  - 44 psig is an Oyster Creek plant specific maximum design pressure, approved in Tech Spec amendment 165
  - Analysis demonstrated increased margin for the minimum required thickness

# Summary of Drywell Corrosion

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- 2006 Refueling outage monitoring results
  - Low leakage from reactor cavity liner
    - Approximately 1 gpm
  - No water in the sand bed region
  - Epoxy coating 100% visual inspection in all bays
    - In good condition
  - UT grid measurements in sand bed region from inside the drywell
    - No corrosion
  - Local UT measurements in sand bed from outside
    - The drywell shell exceeds required thickness
  - UT grid measurements in upper elevations
    - No corrosion except 1 location shows 0.66 mils/yr

# Sand Bed Region 1992

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Drywell
Shell

Corrosion product on drywell vessel

# Sand Bed Region 1992

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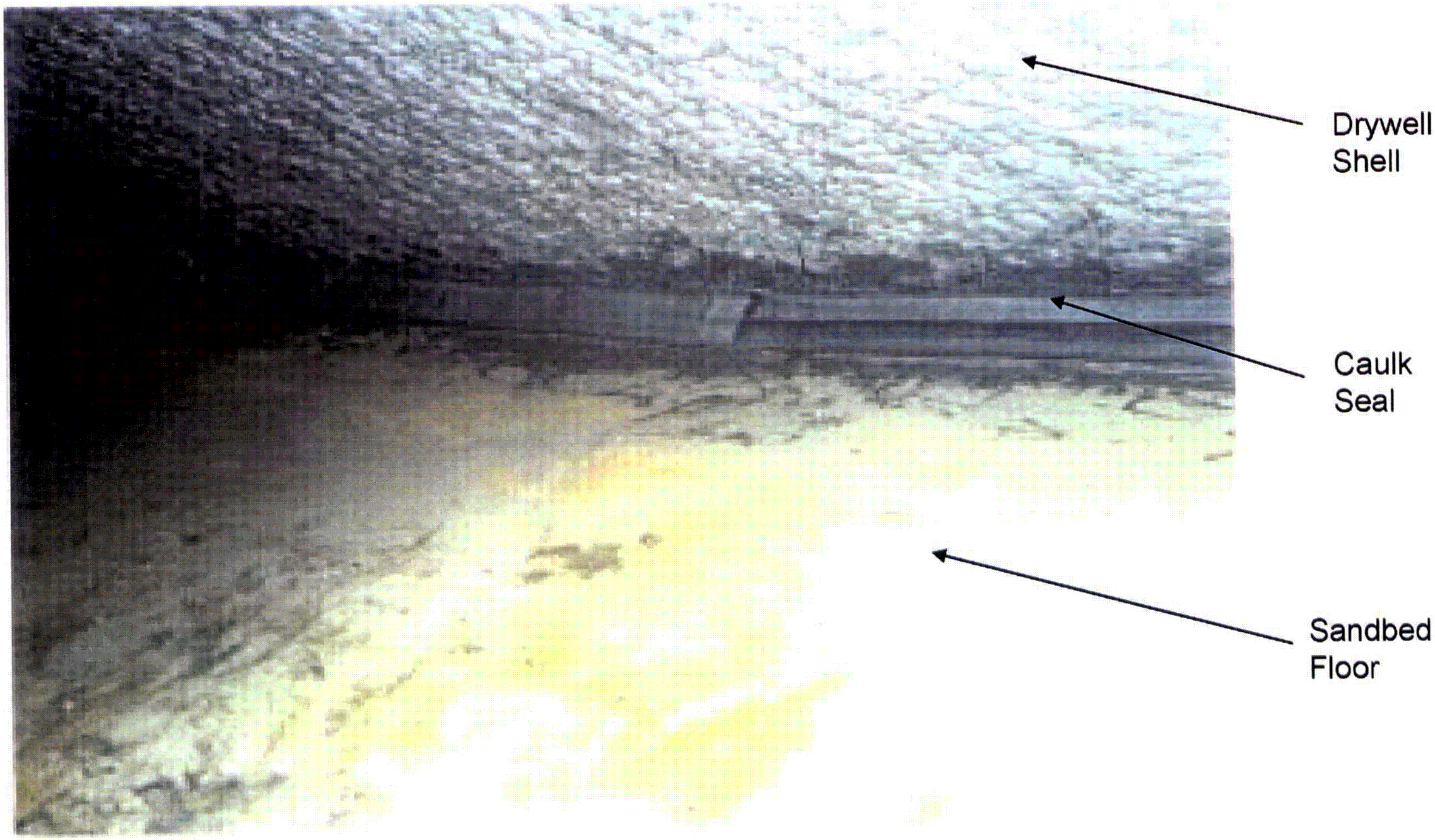


Finished floor, vessel with two top coats – caulking material applied

# Sand Bed Region 2006

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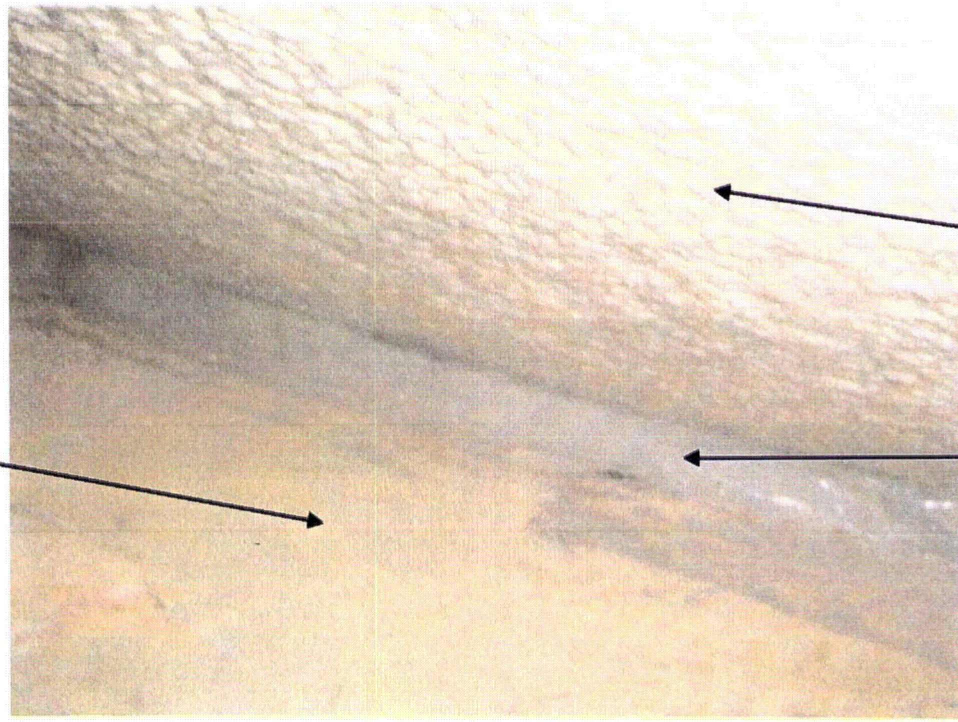


Bay 19 caulking

Drywell Shell Bay 19

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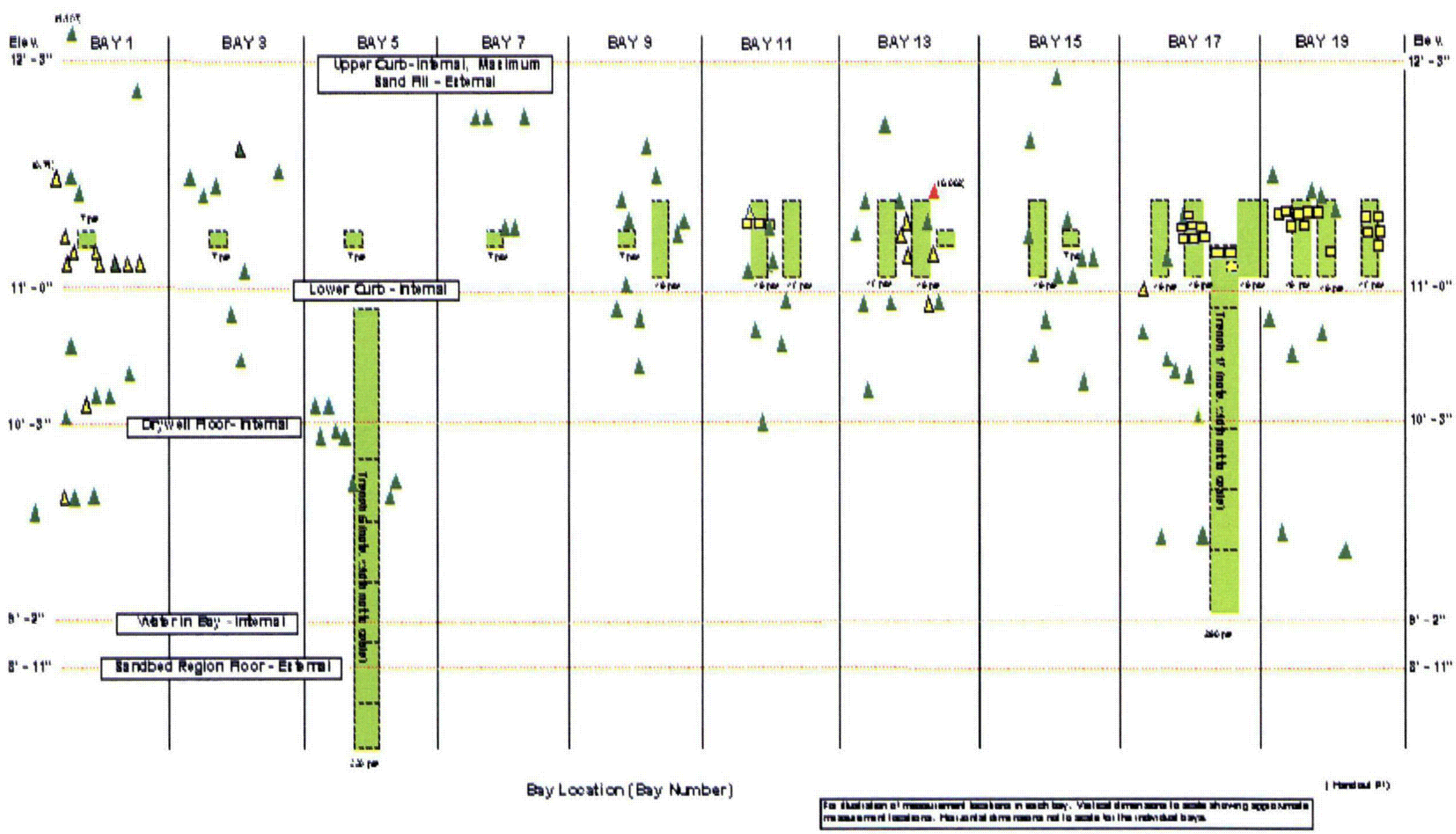
## 2006 Measurement Locations in the Sandbed Region

**Color Code for thickness:**
Green = UT Measurements > 736 Mils
Yellow = UT Measurements Between 636 and 736 Mils
Red = UT Measurements Between 536 and 636 Mils

**Location / Type of UT Measurement**
△ External Point UT Measurements
⬚ Internal Grid UT Measurements
□ Internal Point UT Measurements



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# Minimum Available General Thickness Margins

| Bay No. | 1 | 3 | 5 | 7 | 9 | 11 | 13 | 15 | 17 | 19 |
|---|---|---|---|---|---|---|---|---|---|---|
| Minimum Available Margin, mils | 365 | 439 | 432 | 397 | 256 | 84 | 101 | 306 | 74 | 64 |

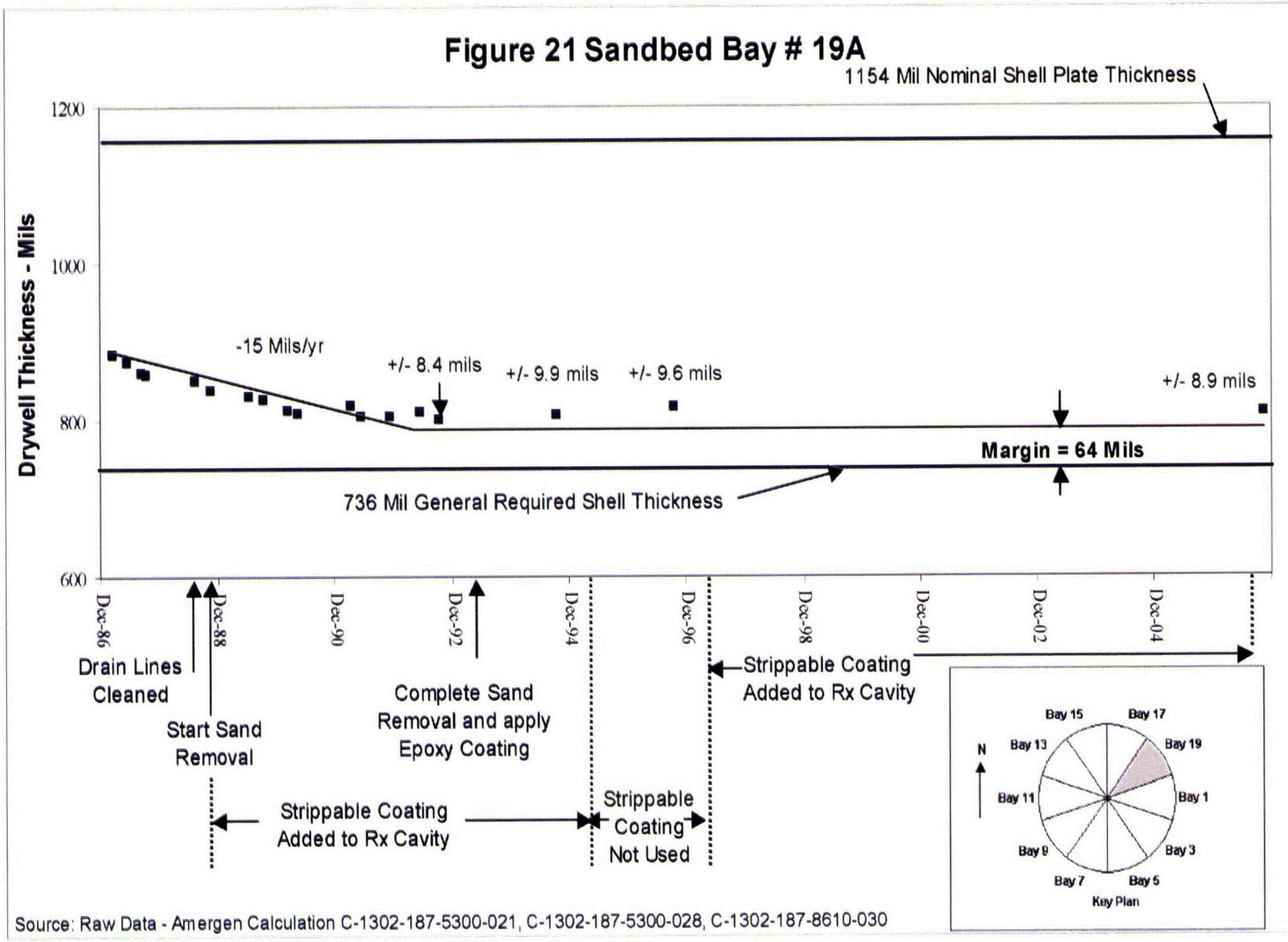
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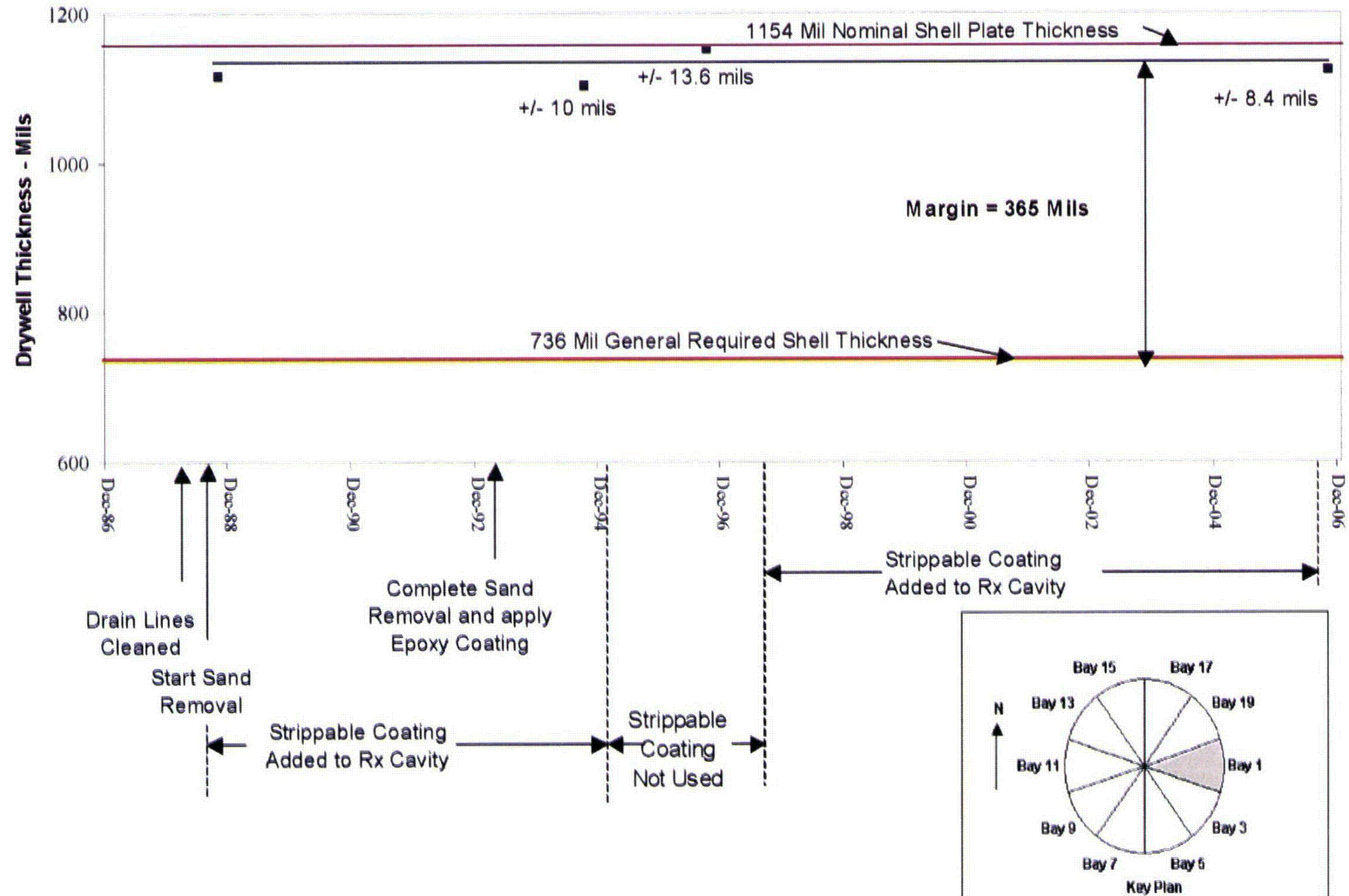
Figure 21 Sandbed Bay # 19A
1154 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
1200
1000
800
600
-15 Mils/yr
+/- 8.4 mils
+/- 9.9 mils
+/- 9.6 mils
+/- 8.9 mils
Margin = 64 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Drain Lines Cleaned
Start Sand Removal
Complete Sand Removal and apply Epoxy Coating
Strippable Coating Added to Rx Cavity
Strippable Coating Not Used
Strippable Coating Added to Rx Cavity
Bay 15
Bay 17
Bay 13
Bay 19
N
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

**Figure 1. Sandbed Bay # 1D**




Source: Raw Data - AmerGen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-

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# Drywell Shell Current Condition

| Drywell Region | Nominal Design Thickness, mils | Minimum Measured General Thickness, mils | Minimum Required General Thickness, mils | Minimum Available Thickness Margin, mils |
|---|---|---|---|---|
| Cylindrical | 640 | 604 | 452 | 152 |
| Knuckle | 2,625 | 2,530 | 2260 | 270 |
| Upper Sphere | 722 | 676 | 518 | 158 |
| Middle Sphere | 770 | 678 | 541 | 137 |
| Lower Sphere | 1154 | 1160 | 629 | 531 |
| Sand Bed | 1154 | 800 | 736 | 64 |

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# Commitment Summary

- UT thickness measurements in various areas of sand bed and upper drywell regions
- Strippable coating will be applied to the reactor cavity liner every refuel outage
- Leakage monitoring of cavity trough drain and sand bed drains
- Visual inspection of sand bed region shell epoxy coating
- Visual inspection of seal at junction between drywell shell and sand bed region floor
- Visual inspections and UT measurements of the drywell shell in the trench areas
- Visual inspection of moisture barrier inside drywell at junction between shell and floor/curb

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# Overall Conclusions

- The corrective actions to mitigate drywell shell corrosion have been effective
- The drywell shell corrosion has been arrested in the sand bed region and continues to be very low in the upper drywell elevations
- The corrosion on the embedded portion of the drywell shell is not significant
- The drywell shell meets code safety margins
- We have an effective aging management program to ensure continued safe operation

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# Drywell Shell Corrosion

## Issues from January 18, 2007 Subcommittee Meeting

1. Capacity Reduction Factor
2. Buckling Analysis
3. Reactor Cavity Liner Leakage
4. Future Monitoring Programs
5. Interior Surface of the Embedded Drywell Shell

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# Capacity Reduction Factor

## Subcommittee Issue # 1:

The GE analysis and Sandia analysis are different. A key difference is that the GE analysis increased the capacity reduction factor for the refueling load combination case when there is no internal pressure present. Is this acceptable?

## Response:

The increased capacity reduction factor used in the GE analysis is acceptable.

# Capacity Reduction Factor Conclusions

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- The GE analysis in 1992 increased the capacity reduction factor from 0.207 to 0.326 to account for orthogonal tensile stresses in a sphere
- Buckling tests conducted on spheres show a reduction in the effect of imperfections on the buckling strength
- The application of an increased capacity reduction factor to the Sandia analysis produces results similar to the GE analysis
- AmerGen's conclusion is that the GE analysis, including a minimum uniform thickness in the sand bed region of 736 mils, is valid

# Buckling Analysis Details

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- Buckling Analysis followed the methodology outlined in ASME Code Case N-284

  Allowable Compressive Stress = $\eta_i \, \alpha_i \, \sigma_{ie}/\mathbf{FS}$

  $\eta_i$ = Plasticity Reduction Factor

  $\alpha_i$ = Capacity Reduction Factor

  $\sigma_{ie}$ = Theoretical Elastic Buckling Stress

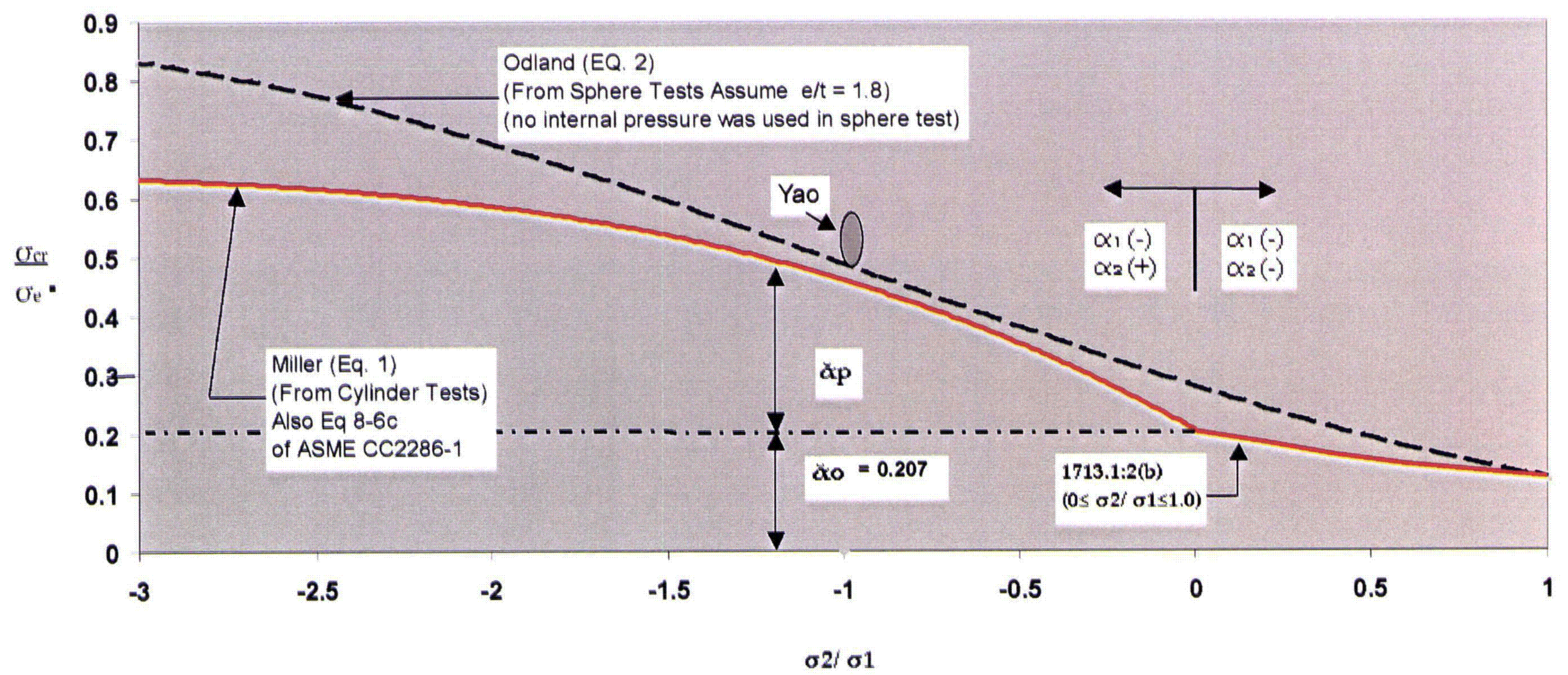
  **FS** = Factor of Safety (2.0 for refueling condition and 1.67 for post-accident condition)

- Capacity Reduction Factor, $\alpha_i$ , was increased to account for the effect of a coexisting orthogonal tensile stress
  - The increase was based upon tests conducted on cylinders
  - Tests conducted on spherical segments concluded that the modified $\alpha_i$ based on cylinder test results is conservative

# Modified Capacity Reduction Factor

- ASME Code Case N-284 allows modifying the capacity reduction factor to account for the effect of orthogonal tensile stress on buckling strength.
  - The effect of orthogonal tensile stress due to internal pressure is well documented for cylinders.
- The N-284 capacity reduction factor is modified using formulas developed by C. D. Miller. The formulas are based on tests conducted on cylinders.
- Tests conducted on spheres, without internal pressure, show that the coexistence of orthogonal tensile stress reduces the effect of imperfections on the buckling strength of spheres
  - Orthogonal tensile stresses are a result of in-plane tension or compression loads.
- The modified capacity reduction factor is now used in ASME Code Case 2286-1 for spheres.
- The following figure shows that the modified formula is conservative for spheres.

# Capacity Reduction Factor for Spheres



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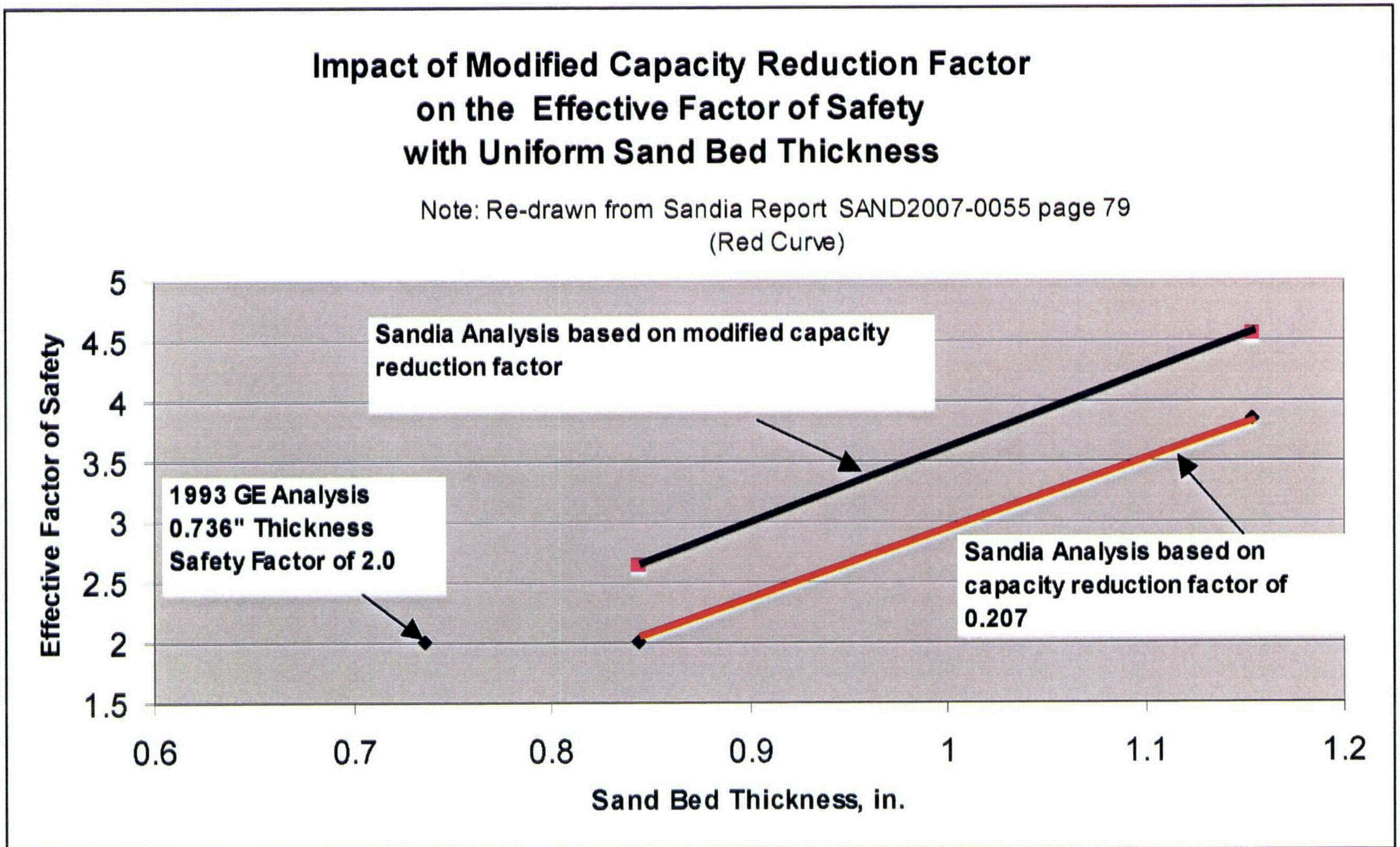
# Impact of Modified Capacity Reduction Factor on Buckling Stress

| Parameter | Sandia without Modified $\alpha_i$ | Sandia with Modified $\alpha_i$ |
|---|---|---|
| As analyzed Thickness | 0.842 | 0.842 |
| Theoretical Elastic Instability Stress, ksi | 46.49 | 46.49 |
| Capacity Reduction Factor | 0.207 | 0.207 |
| Circumferential Stress (Orthogonal tensile stress), ksi | | 2.5* |
| Equivalent Pressure, psi | | 10.02 |
| "X" Parameter | | 0.042 |
| ΔC | | 0.039 |
| Modified Capacity Factor | | 0.272 |
| Elastic Buckling Stress, ksi | | 12.65 |
| Proportional Limit Ratio | 0.253 | 0.333 |
| Plasticity Reduction Factor | 1.0 | 1.0 |
| Inelastic Buckling Stress, ksi | 9.62 | 12.65 |
| Code Required Factor of Safety, FS | 2.0 | 2.0 |
| Allowable Compressive Stress, ksi | 4.81 | 6.33 |
| Applied Compressive Stress, ksi | 4.47 | 4.47 |
| Calculated Safety Factor | 2.15 | 2.83 |

Assumed average orthogonal tensile stress based on 8 ksi orthogonal tensile stress given in Sandia Report Table 3-2.


Impact of Modified Capacity Reduction Factor
on the Effective Factor of Safety
with Uniform Sand Bed Thickness
Note: Re-drawn from Sandia Report SAND2007-0055 page 79
(Red Curve)
Sandia Analysis based on modified capacity reduction factor
1993 GE Analysis
0.736" Thickness
Safety Factor of 2.0
Sandia Analysis based on capacity reduction factor of 0.207
Effective Factor of Safety
5
4.5
4
3.5
3
2.5
2
1.5
0.6
0.7
0.8
0.9
1
1.1
1.2
Sand Bed Thickness, in.

# NRC Issued SER for Drywell Analysis – April 24, 1992

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- Numerous exchanges of technical information between Licensee, GE, Code Case Expert and NRC in early 1990s
- In its SER, the Staff discussed the methodology Oyster Creek used to perform buckling analysis and specifically addressed the use of a modified capacity reduction factor
- Brookhaven National Laboratory supported the NRC Staff in performance of this review
- The Staff concluded that the drywell meets ASME Section III Subsection NE requirements

# Capacity Reduction Factor Conclusions

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- The GE analysis in 1992 increased the capacity reduction factor from 0.207 to 0.326 to account for orthogonal tensile stresses in a sphere
- Buckling tests conducted on spheres show a reduction in the effect of imperfections on the buckling strength
- The application of an increased capacity reduction factor to the Sandia analysis produces results similar to the GE analysis
- AmerGen's conclusion is that the GE analysis, including a minimum uniform thickness in the sand bed region of 736 mils, is valid

# Buckling Analysis

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## Subcommittee Issue # 2:

Thickness margin may be better understood with a modern 3D finite element model where various thickness and thickness configurations in the sand bed region could be evaluated.

## Response:

1. Our current licensing basis analysis demonstrates that code requirements are met.
2. Use of a modern modeling technique, inputting actual shell thicknesses, should demonstrate more thickness margin.
3. AmerGen will perform a 3D finite element analysis of the Oyster Creek drywell using modern methods. This analysis will be completed prior to entering the period of extended operation.

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# Reactor Cavity Liner Leakage

## Subcommittee Issue # 3:

Leakage through the reactor cavity liner should be eliminated.

## Response:

AmerGen will perform an engineering study prior to the period of extended operation to investigate cost effective replacement or repair options to eliminate Reactor Cavity Liner leakage.

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# Future Monitoring Programs

## Subcommittee Issue # 4:

The monitoring of drywell shell thickness should be more aggressive in the short term.

## Response:

The next slide shows the breadth and frequency of monitoring activities associated with the drywell shell. These activities include inspections to monitor the condition of the drywell shell so that any additional corrosion would be detected before the existing margin was eliminated.

# Summary of Drywell Monitoring Activities During Refueling Outages

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| Drywell Monitoring Activities Performed During Refueling Outages | Refueling Outage Date | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2008 | 2010 | 2012 | 2014 | 2016 | 2018 | 2020 | 2022 | 2024 | 2026 | 2028 |
| **Verification of Elimination of Water Leakage into Sand Bed Region** | | | | | | | | | | | | |
| 1) Cavity Liner – Apply Tape & Strippable Coating | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| 2) Cavity Drain – Confirm Drain is Clear | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| 3) Cavity Drain – Monitor Flow Rate | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily |
| 4) Sand Bed Drains – Confirm No Water | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily | Daily |
| **Upper Drywell Shell Monitoring** | | | | | | | | | | | | |
| 1) UT Inspections – Upper Drywell Transition Areas Inside Drywell @ 71'-6" | 2 Areas | 2 Areas | 2 Areas | 2 Areas | If corrosion is greater than the Upper Drywell locations, UTs will be continued at same frequency as the Upper Drywell 13 Locations | | | | | | | |
| 2) UT Inspections – Upper Drywell 13 Locations Inside Drywell @ 87'-5", 60'-10", 51'-10", 50'-2" | 100% | | 100% | | 100% | | 100% | | 100% | | 100% | |
| 3) UT Inspections – Drywell Transition Areas Inside Drywell @ 23'-6" | 2 Areas | 2 Areas | 2 Areas | 2 Areas | If corrosion is greater than the Upper Drywell locations, UTs will be continued at same frequency as the Upper Drywell 13 Locations | | | | | | | |
| **Sand Bed Region Shell Monitoring** | | | | | | | | | | | | |
| 1) UT Inspections – Sand Bed 19 Locations Inside Drywell @ 11'-3" | 100% | | 100% | Subsequent UT inspection frequency will be established as appropriate, not to exceed a 10-year interval | | | | | | | | |
| 2) VT Inspection of Sand Bed External Epoxy Coating and Shell to Floor Caulk Seal | All 10 Bays | | At Least 3 Bays | | At Least 3 Bays | | 10 in 10 yrs | At Least 3 Bays | | At Least 3 Bays | | 10 in 10 yrs |
| 3) UT Inspections – Sand Bed 106 External Locally Thinned Locations | 10 Bays | 10 Bays | Bay 1 & 13 | 2 Bays | 2 Bays | 2 Bays | 2 Bays | 2 Bays | 2 Bays | 2 Bays | 2 Bays | 2 Bays |
| 4) VT Inspection of Drywell Shell in Trench Locations Inside Drywell | 100% | 100% | 100% | VT inspections will continue each outage if trenches are not restored. | | | | | | | | |
| 5) UT Inspection of Drywell Shell in Trench Locations Inside Drywell | 626 Points | 626 Points | 626 Points | UT inspections will continue each outage if trenches are not restored. | | | | | | | | |
| 6) Inspection for Water in Trenches | Yes | Yes | Yes | If water is not observed in trenches for 2 consecutive outages, trenches will be restored and no further inspections will be required. | | | | | | | | |
| **General Monitoring** | | | | | | | | | | | | |
| 1) Structures Monitoring – Visual Inspection of Concrete Floor, Trough & Shell Inside Drywell | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| 2) Structures Monitoring – Visual Inspection of Sump | Yes | | Yes | | Yes | | Yes | | Yes | | Yes | |
| 3) Appendix J Test – Pressure Test and Visual Inspection of Accessible Int. and Ext. Shell Surfaces | | | Test | | | | | Test | Perform Test Within Ten Years of Previous Test | | | |
| 4) Drywell Service Level 1 Coating Inspection Inside Drywell | Yes | | Yes | | Yes | | Yes | | Yes | | Yes | |
| 5) Structures Monitoring – Visual Inspection of Moisture Barrier between Drywell Shell and Concrete Curb Inside Drywell | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

# Interior Surface of the Embedded Drywell Shell

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## Subcommittee Issue # 5:

The trenches in the drywell floor should not be restored to the design configuration until sufficient monitoring is completed to verify corrective actions to eliminate water on the interior drywell shell have been effective.

## Background:

The water source has been identified and corrective actions have been implemented. Corrosion of steel embedded in concrete is mitigated by the high pH of the water and by the passive, protective film on the steel surface.

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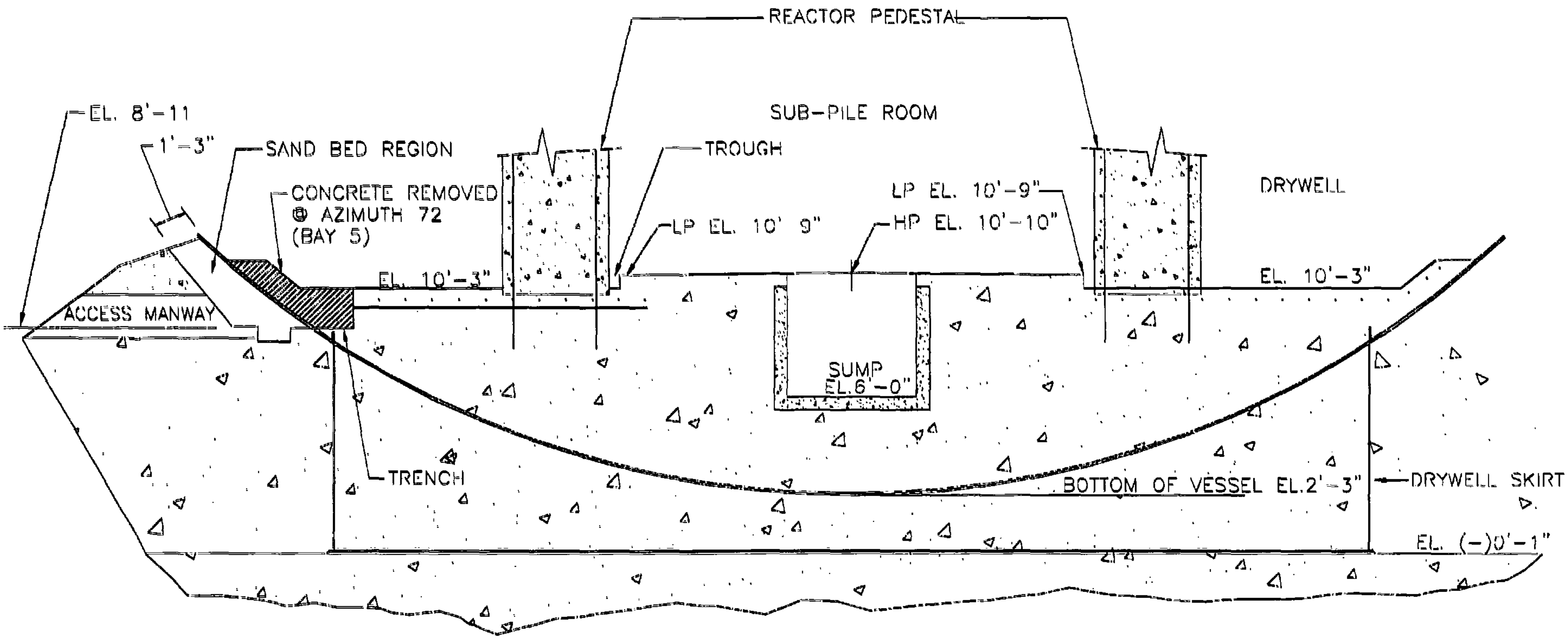
# LOWER DRYWELL- SANDBED, TRENCH & SUMP




ELEVATION LOOKING WEST

# Interior Surface of the Embedded Drywell shell

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## Response to Issue # 5:

The trenches in the drywell interior floor

- Inspect during refueling outages for water.
- Visual/UT exams of shell within trenches.
- After confirming in 2 consecutive refueling outages there is no water in the trenches, restore the trenches to their original design condition.

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# License Renewal Application Summary

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# Description of Oyster Creek

- Located in Lacey Township, Ocean County, New Jersey
- Barnegat Bay is Ultimate Heat Sink
- GE BWR 2 with Mark I Containment
- Licensed thermal power 1930 MWth
- Design electrical rating 650 MWe
- Interim Spent Fuel Storage established onsite
- Overall CDF
  - Internal events: 1.1E-05/year
  - LERF: 5.8E-07/year

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# Current Plant Status

- Operating license expires April 9, 2009
- Operating in 21st cycle
- Transitioned to 24 month cycles in 1991
- Completed 21st refueling outage in November 2006
- Regulatory Oversight Program (ROP) status

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# License Renewal Methodology

- LRA submitted July 22, 2005
- NEI 95-10 Rev. 6 Standard Format
- Prepared using NUREG 1800 (SRP) and NUREG 1801 (GALL) January 2005 draft revisions
- AmerGen prepared a reconciliation document comparing the Oyster Creek LRA to NUREGs 1800 and 1801 Rev. 1.

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# Aging Management Programs

- 50 GALL programs
  - 18 existing
  - 14 existing requiring enhancements
  - 18 new (10 associated with Forked River Combustion Turbines)
- 7 Plant specific programs
  - 2 existing
  - 2 existing requiring enhancements
  - 3 new (1 associated with Forked River Combustion Turbines)

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# Commitment Management

- 65 commitments are listed in Appendix A of the application.
- A commitment tracking number has been issued for these license renewal commitments
- An associated action containing the details was issued for each of the commitments
- Each implementing procedure is annotated to provide linkage to and preserve the details of the commitment
- Process controlled by the commitment management procedure

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# Status of Program Implementation

- 257 new and 111 enhanced implementation activities identified
  - 13% completed in 2006 refueling outage
  - 19% in 2008 refueling outage scope
  - 68% to be performed on-line

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# Summary

- Aging Management Programs are established to ensure safe operation for period of extended operation
- License renewal commitments are tracked and will be implemented as expected
- On track for completing activities prior to entering period of extended operation

Approval Date: March 14, 1995

*See Numeric Index for expiration and any reaffirmation dates.*

**Case N-284-1**
**Metal Containment Shell Buckling Design Methods, Class MC**
**Section III, Division 1**

*Inquiry:* Are there alternatives to the requirements of NE-3222 for determining allowable compressive stresses for Section III, Division 1, Class MC construction?

*Reply:* It is the opinion of the Committee that, for Section III, Division 1, Class MC construction, the provisions of this Case, as follow, may be used as an alternative to the requirements of NE-3222.

# CONTENTS

**Figures**



**Table**

## -1000 METAL CONTAINMENT SHELL BUCKLING DESIGN METHODS

## -1100 INTRODUCTION

### -1110 Scope

The design of a class MC containment vessel against buckling shall be based on the requirements of Subsection NE of the Code. NE-3133 provides specific design rules for unstiffened or ring stiffened cylindrical shells, spherical shells and formed heads under external pressure and unstiffened cylinders under axial compression. NE-3222.1(a) and (c) provide general guidelines for other shell geometries and loading conditions. The purpose of this Case is to provide stability criteria for determining the structural adequacy against buckling of containment shells with more complex shell geometries and loading conditions than those covered by NE-3133. Such effects as symmetrical or unsymmetrical dynamic loading conditions, circumferential and/or meridional stiffening for heads as well as cylindrical shells, combined stress fields, discontinuity stresses and secondary stresses are considered in the stability evaluation.

Acceptable stress analysis procedures and methods for determining stress components to be used in the stability evaluation are given. The buckling capacity of the shell is based on linear bifurcation (classical) analyses reduced by capacity reduction factors which account for the effects of imperfections and nonlinearity in geometry and boundary conditions and by plasticity reduction factors which account for nonlinearity in material properties.

**-1111 Limitations.** The procedures of -1710 and -1720 assume an axisymmetric structure. All containment vessels have penetrations which are nonaxisymmetric with respect to the containment vessel. Studies and experience have shown that penetrations which are fully reinforced according to the Code rules, and which have an inside diameter that is small compared to the vessel diameter, will not reduce the buckling strength of the overall structure. Paragraphs -1710 and -1720 may be used without special consideration of properly reinforced penetrations that have an inside diameter not greater than 10% of the vessel diameter. The effect of larger penetrations shall be considered in the Design Report.

The rules of this Case are applicable to shells with radius-to-thickness ratios of up to 1000 and shell thickness of $\frac{1}{4}$ in. or greater. Any vessel design using less conservative procedures or involving cases not covered by this Case shall be justified in the Design Report.

### -1120 Basic Buckling Design Values

The basic allowable buckling stress values permitted by the Code are specified in NE-3131(b), NE-3133 and NE-3222.

The basic Code buckling rules as well as the rules of this Code Case are based on the fabrication requirements of NE-4222.

The methods of buckling evaluation are given in -1700. The buckling evaluation is made by either of two methods. The first method is contained in -1710 and utilizes formulae and interaction equations which must be satisfied. The alternate method involves checking the adequacy against buckling as computed by computer codes in accordance with -1720 or -1730. The procedures for these methods are outlined below and summarized in -1800.

For both methods the following items are calculated: (1) a set of stress components, $\sigma_i$, from applied loads are computed in accordance with -1300, (2) a factor of safety, $FS$, is determined from -1400, (3) capacity reduction factors, $\alpha_{ij}$, are computed from -1500, and (4) plasticity reduction factors, $\eta_i$, are obtained from -1600.

When using the formulae in -1710, theoretical elastic buckling stresses for special loading cases ($\sigma_{\phi ej}$, $\sigma_{rej}$, $\sigma_{\phi\theta ej}$, and $\sigma_{hej}$) are computed from -1712. The corresponding allowable stresses for elastic and inelastic buckling (e.g., $\sigma_{xa} = \alpha_{\phi j}\ \sigma_{\phi j}/FS$, and $\sigma_{xc} = \eta_{\phi}\ \sigma_{xa}$) are then computed in -1713. The interaction equations of -1713 are then used to determine the adequacy of design for other than the special loading cases.

When the buckling evaluation is by computer codes per -1720 and -1730, sets of amplified stress components $\sigma_{is} = \sigma_i FS/\alpha_{ij}$ and $\sigma_{ip} = \sigma_{is}/\eta_i$ are calculated and compared with the linear bifurcation predictions of the computer codes.

## -1200 NOMENCLATURE

$i = \phi, \theta$, or $\phi\theta$ corresponding to meridional direction or stress component, circumferential direction or stress component, and in-plane shear stress component, respectively

$i = 1$ or $2$ corresponding to $\phi$ or $\theta$ above where 1 corresponds to the larger compression stress and 2 corresponds to the smaller compression stress

$i = x, h, r, \tau$ to denote the special loading cases of axial (or meridional) compression alone, hydrostatic external pressure, radial external pressure, and in-plane shear.

$j = L, S, G$ corresponding to local buckling (buckling of shell plate between stiffeners or boundaries), stringer buckling (buckling between rings of the shell plate and attached meridional stiffeners, and general instability (overall collapse), respectively

$A_i$ = cross-sectional area of stiffener (no effective shell included), sq in. $i = \phi$ for meridional (longitudinal or stringer) stiffeners, $i = \theta$ for circumferential (ring) stiffeners

$C_i$ = elastic buckling coefficients

$= \dfrac{\sigma_{ieL} R}{Et}$

$C_{\theta r}$, $C_{\theta h}$ = elastic buckling coefficients in hoop direction for cylinders under uniform external pressure, $\sigma_\phi = 0$ and $\sigma_\phi = 0.5\sigma_\theta$, respectively

$E$ = modulus of elasticity of the material at Design Temperature, psi.

$FS$ = factor of safety

$G = \dfrac{E}{2(1+\mu)}$

$h_s$ = width or depth of elements of a stiffener, in.

$I_i$ = moment of inertia of stiffener in the $i$ direction, about its centroidal axis, in.$^4$

$I_{Ei}$ = moment of inertia of stiffener plus effective width of shell $\ell_e$ ($\ell_e = \ell_{e\phi}$ for circumferential stiffeners and $\ell_e = \ell_{e\theta}$ for meridional stiffener), about centroidal axis of combined section, in the $i$ direction, in.$^4$

$= I_i + A_i z_i^2 \dfrac{\ell_e t}{A_i + \ell_e t} + \dfrac{\ell_e t^3}{12}$

$I_{FE}$ = value of $I_{E\theta}$ which makes a large stiffener fully effective, that is, equivalent to a bulkhead

$J_i$ = torsional constant of stiffener for general non-circular shapes use $\Sigma(h_s t_s^3/3)$, in.$^4$

$K$ = the ratio of the axial membrane force per unit length to the hoop compressive membrane force per unit length

$= \dfrac{\sigma_\phi}{\sigma_\theta}\dfrac{t_\phi}{t_\theta}$

$K_s = 1 - \left(\dfrac{\sigma_{\phi\theta}}{\sigma_{\tau a}}\right)^2$

$L$ = overall length of cylinder, in.

$L_B$ = length of cylinder between bulkheads or lines of support with sufficient stiffness to act as bulkheads, in. Lines of support which act as bulkheads include end stiffeners which satisfy -1714(b)(2), a circumferential line on an unstiffened head at one-third the depth of the head from the head tangent line, a circumferential line at point of embedment in or anchorage to a concrete foundation, and the cylinder to head junction when the head is designed in accordance with this Case for stiffened heads.

$L_s$ = one-half of the sum of the distances $L_B$ on either side of an end stiffener, in.

$\ell_i$ = distance in $i$ direction between lines of support, in. A line of support includes any intermediate size stiffening ring which satisfies the requirements of this Case in addition to the lines of support included in the definition for $L_B$.

$\ell_{si}$ = one-half of the sum of the distances $\ell_i$ on either side of an intermediate size stiffener, in.

$\ell_{ei}$ = effective width of shell acting with the stiffener in the $i$ direction, in.

$= 1.56\sqrt{Rt}$ unless otherwise noted

$M_i = \ell_i / \sqrt{Rt}$

$M_s = \ell_{si} / \sqrt{Rt}$

$M$ = smaller of $M_\phi$ and $M_\theta$

$m$ = number of half waves into which shell will buckle in the meridional direction

$n$ = number of waves into which shell will buckle in the circumferential direction

$R$ = shell radius, in.

$R_c$ = radius to centroidal axis of the combined stiffener and effective width of shell, in.

$R_1$, $R_2$ = effective stress radius for toroidal and ellipsoidal shells in the $\phi$ and $\theta$ directions, respectively, in. See Fig. -1713.1.3-1

$t$ = shell thickness, in.

$t_s$ = thickness of elements of a stiffener, in.

$t_\phi, t_\theta, t_{\phi\theta} = \dfrac{A_\phi}{\ell_\theta} + t,\ \dfrac{A_\theta}{\ell_\phi} + t,\ 0.5\,(t_\phi + t_\theta)$

$z_i$ = distance from centerline of shell to centroid of stiffener (positive when stiffeners are on outside), in.

$\alpha_{ij}$ = capacity reduction factors to account for the difference between classical theory and predicted instability stresses for fabricated shells ($\alpha_{i\tau} = \alpha_{i\zeta}$)

$\eta_i$ = plasticity reduction factor to account for non-linear material behavior, including effects of residual stress

$\lambda, \bar{\lambda} = \frac{\pi R}{\ell_\phi}, \frac{\pi R}{L_B}$

$\lambda_c$ = the lowest multiples of the prebuckling stress states $\sigma_{is}$ and $\sigma_{ip}$ which cause linear bifurcation buckling

$\mu$ = Poisson's ratio

$\sigma_i$ = calculated membrane stress components due to applied loads, psi

$\sigma_{iej}$ = theoretical elastic instability stresses, psi

$\sigma_{ia}, \sigma_{ic}$ = allowable stresses for elastic and inelastic buckling, respectively, psi

$\sigma_{is}$ = amplified stress components to be used for elastic buckling stress evaluation, psi
$= \sigma_i \cdot FS/\alpha_{ij}$

$\sigma_{ip}$ = amplified stress components to be used for inelastic bifurcation buckling stress evaluations, psi
$= \sigma_{is}/\eta_i$

$\sigma_{rej}, \sigma_{hej}$ = theoretical elastic instability stresses in the hoop direction for cylinders under external pressure, $K = 0$ and $K = 0.5$, respectively, psi

$\sigma_y$ = tabulated yield stress of material at Design Temperature, psi. (Section II, Part D, Subpart 1, Table Y-1)

## -1300 STRESS ANALYSIS PROCEDURES

The governing factor in the buckling analysis of a containment shell is the compressive membrane stress zones in the vessel arising from the static or dynamic response of the vessel to the applied loadings. The procedures of this Case call for static or dynamic linear shell analyses. Geometric nonlinear analysis may be used. The analysis should account for the dynamic effects associated with any dynamically applied loads. The shell analysis may be performed by the axisymmetrical shell of revolution method of -1310 or by alternate methods. The more elaborate, three-dimensional thin shell analysis method of -1320 may be used if the vessel geometry and/or the magnitude of any attached masses are such that axisymmetric shell of revolution analysis is not appropriate. Thermal and other secondary stresses will be treated the same as primary stresses. Fluid-structure interaction should be included in the dynamic analysis.

### -1310 Axisymmetric Shell of Revolution Analysis

Most containment vessels can be adequately modeled as axisymmetric structures for determining their overall response to the applied loads. The mass of local attachments should be smeared around the shell at the applicable elevations. A separate, uncoupled analysis of significant attached masses can be performed, if required. Non-axisymmetric loadings shall be applied by use of an adequate number of Fourier harmonics. Ring stiffeners, if any, can be modeled discretely or an equally accurate representation shall be used and verified in the Design Report. Longitudinal stiffeners on cylinders and radial stiffeners on doubly-curved shells can be modeled as an orthotropic layer, if the stiffener spacing is close enough to make the shell plate between stiffeners fully effective. A method for determining the effective width of shell for longitudinally stiffened cylinders is given in -1712.2.2. This method may also be applied to doubly curved shells when the capacity reduction factors are determined on the basis of an equivalent cylinder.

### -1320 Three-Dimensional Thin Shell Analysis

For those vessels containing major attachments capable of signifcantly altering the overall response of the vessel, the coupling effects of the vessel and the attachment may have to be accounted for. This can be done by the use of a three-dimensional thin shell finite element analysis or an equally valid analysis which shall be verified in the Design Report. The model used for such analysis should be refined enough to adequately account for coupling effects of the vessel and its attachments and to provide an accurate estimate of stresses due to applied static and dynamic loadings. The procedure given in -1310 for modeling stiffeners should be followed.

### -1330 Determination of Stress Components for Buckling Analysis and Design

The internal stress field which controls the buckling of a cylindrical, spherical, toroidal or ellipsoidal shell consists of the longitudinal membrane, circumferential membrane, and in-plane shear stresses. These stresses may exist singly or in combination, depending on the applied loading. Only these three stress components are considered in the buckling analysis.

For the dynamic loading case, the stress results from a dynamic shell analysis are screened for the maximum value of the longitudinal compression, circumferential compression, or in-plane shear stress at each area of interest in the shell. The maximum value thus chosen is taken together with the other two concurrent stress components (here one or both components may be tension) to form a set of quasi-static buckling stress components. For each particular area of interest, three sets of quasi-static buckling stress components corresponding to the three maximum values are used to investigate the buckling capacity of the shell. The analyst should also review the results of the dynamic analysis for additional sets of quasi-static stress components which may represent a more severe condition than those defined above, and include them in the buckling investigation.

When the applied loading causes static or quasi-static stresses which vary in longitudinal and/or circumferential directions within the particular area of interest, each set of stress components along any circumference may be assumed to act uniformly over the entire circumference. For three-dimensional thin shell bifurcation analysis, the actual stress fields may be used.

When combining the effects of different applied loads which act concurrently, each of the three stress components is summed algebraically. If the sum of the longitudinal or circumferential components is tension, then that stress component may be set to zero.

## -1400 FACTORS OF SAFETY

The basic compressive allowable stress values referred to by NE-3222.1 will correspond to a factor of safety of two in this Case. This factor is applied to buckling stress values that are determined by classical (linear) analysis and have been reduced by capacity reduction factors determined from lower bound values of test data.

The stability stress limits referred to by NE-3222.2 will correpsond to the following factors of safety, *FS*, in this Case:

*(a)* For Design Conditions and Level A and B Service Limits, $FS = 2.0$

*(b)* For Level C Service Limits the allowable stress values are 120% of the values of (a). Use $FS = 1.67$.

*(c)* For Level D Service Limits the allowable stress values are 150% of the values of (a). Use $FS = 1.34$.

The factors of safety given above are used in the buckling evaluation of -1700 and are the minimum values required for local buckling. The buckling criteria given in -1700 require that the buckling stresses corresponding to stringer buckling and general stability failures be at least 20% higher than the local buckling stresses.

## -1500 CAPACITY REDUCTION FACTORS

The buckling capacity as determined by linear bifurcation (classical) analysis is not attained for actual shells. The reduction in capacity due to imperfections and nonlinearity in geometry and boundary conditions is provided through the use of capacity reduction factors, $\alpha_{ij}$, given below for shells which meet the tolerances of NE-4220.

Three modes of buckling are considered in this Case. These are: (1) local buckling which is defined as the buckling of the shell plate between stiffeners, (2) stringer buckling which is defined as the buckling between circumferential rings of the shell plate and the attached meridional stiffeners and (3) general instability which is defined as overall collapse of the combined shell and stiffeners. All stiffeners must be proportioned to preclude local buckling of the web or flange of a stiffener. One set of $\alpha_{ij}$ values is given for local buckling and a second set for stringer buckling and general instability.

These capacity reduction factors can be used for both internally or externally stiffened shells as well as unstiffened shells. The influence of internal pressure on a shell structure may reduce the initial imperfections and therefore higher values of capacity reduction factors may be acceptable. Justification for higher values of $\alpha_{ij}$ must be given in the Design Report. This capacity increase may also be applied to the equivalent sphere used in the buckling design of a toroidal or ellipsoidal shell under internal pressure.

### -1510 Local Buckling

In the following paragraphs no increase in buckling stress is recognized for values of $M_i$ less than 1.5.

### -1511 Cylindrical Shells — Stiffened or Unstiffened

*(a) Axial Compression* (See Figs. -1511-1 and -1511-2)

Use the larger of the values determined for $\alpha_{\phi L}$ from (1) and (2).

*(1)* Effect of $R/t$

$$\alpha_{\phi L} = 0.207 \text{ for } R/t \geq 600$$

$$\left.\begin{aligned} \alpha_{\phi L} &= 1.52 - 0.473 \log_{10}(R/t) \\ \alpha_{\phi L} &= \frac{300\sigma_y}{E} - 0.033 \end{aligned}\right\} \text{Use smaller value for } R/t < 600$$

*(2)* Effect of Length

$$\alpha_{\phi L} = 0.627 \text{ if } M_\phi < 1.5$$

$$\alpha_{\phi L} = 0.837 - 0.14M_\phi \text{ if } 1.5 \leq M_\phi < 1.73$$

$$\alpha_{\phi L} = \frac{0.826}{M_\phi^{0.6}} \text{ if } 1.73 \leq M_\phi < 10$$

$$\alpha_{\phi L} = 0.207 \text{ if } M_\phi \geq 10$$

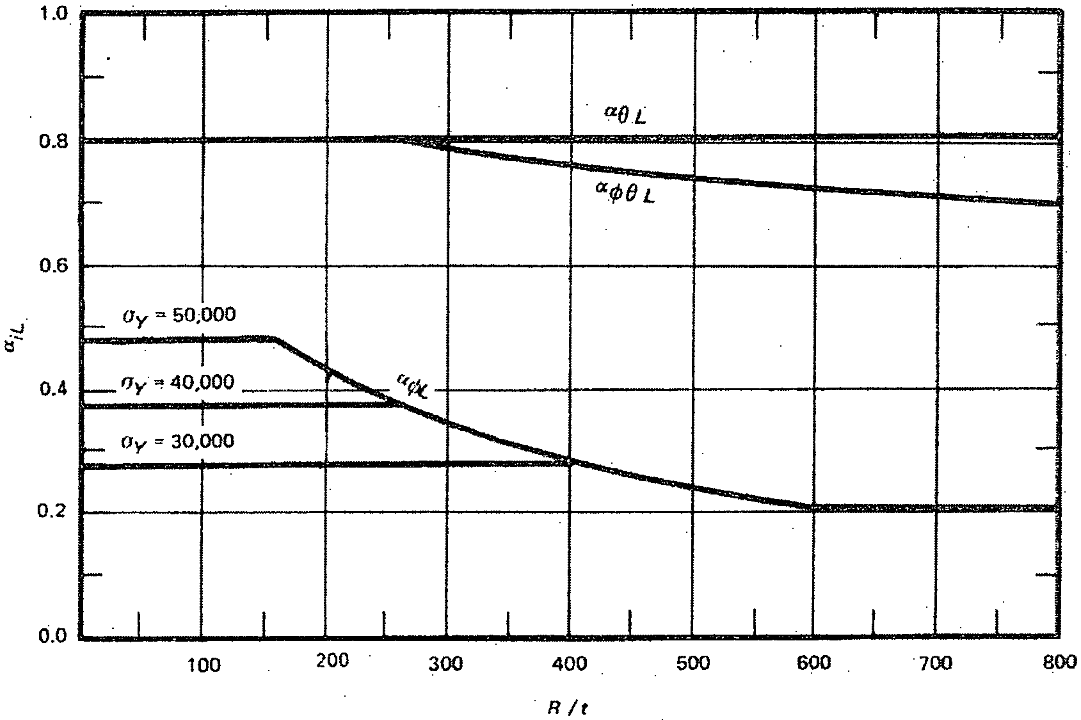



FIG. -1511-1 CAPACITY REDUCTION FACTORS FOR LOCAL BUCKLING OF STIFFENED AND UNSTIFFENED CYLINDRICAL SHELLS (USE LARGER VALUE OF $\alpha_{\phi L}$ FROM FIG. -1511-1 AND FIG. -1511-2)

*(b) Hoop Compression*

$$\alpha_{\theta L} = 0.8$$

*(c) Shear* (See Fig. -1511-1)

$$\alpha_{\phi\theta L} = 0.8 \text{ if } R/t \leq 250$$

$$\alpha_{\phi\theta L} = 1.323 - 0.218 \log_{10} (R/t) \text{ if } 250 < R/t < 1000$$

**-1512 Spherical Shells — Stiffened or Unstiffened.** See Fig. -1512-1 then see -1713.1.2 for method of calculating $M$.

*(a) Uniaxial Compression*

$$\alpha_{\phi L} = \alpha_{\theta L} = \alpha_{1L}$$

$$\alpha_{1L} = \alpha_{2L}/0.6 \qquad \text{(But not to exceed 0.75)}$$

See (b) for $\alpha_{2L}$

*(b) Equal Biaxial Compressive Stresses*

$$\alpha_{\phi L} = \alpha_{\theta L} = \alpha_{2L}$$

$$\alpha_{2L} = 0.627 \qquad \text{if } M < 1.5$$

$$\alpha_{2L} = 0.837 - 0.14M \qquad \text{if } 1.5 \leq M < 1.73$$

$$\alpha_{2L} = \frac{0.826}{M^{0.6}} \qquad \text{if } 1.73 \leq M < 23.6$$

$$\alpha_{2L} = 0.124 \qquad \text{if } M \geq 23.6$$

*(c) Unequal Biaxial Compressive Stresses*
Use $\alpha_{1L}$ and $\alpha_{2L}$ in accordance with -1713.1.2.

*(d) Shear*
Buckling evaluation will be made using principal stresses.

**-1513 Toroidal and Ellipsoidal Shells.** Use the values of $\alpha_{iL}$ given for spherical shells in accordance with -1713.1.3.

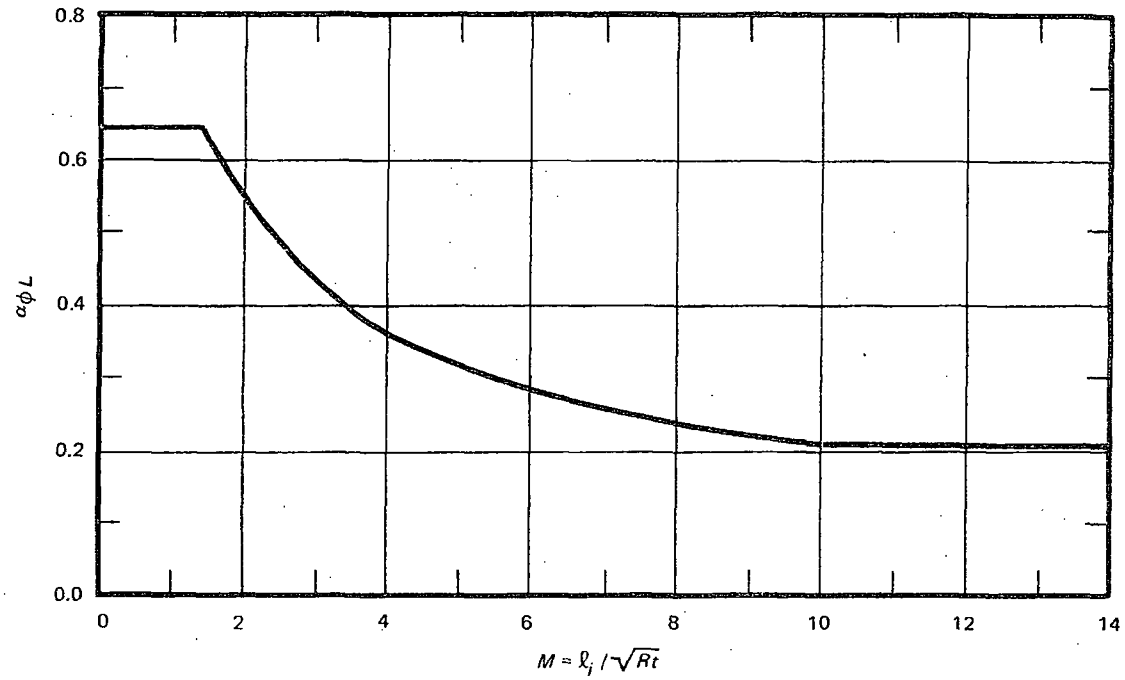



FIG. -1511-2 CAPACITY REDUCTION FACTORS FOR LOCAL BUCKLING OF STIFFENED AND UNSTIFFENED CYLINDRICAL SHELLS (USE LARGER VALUE OF $\alpha_{\phi L}$ FROM FIG. -1511-1 AND -1511-2)

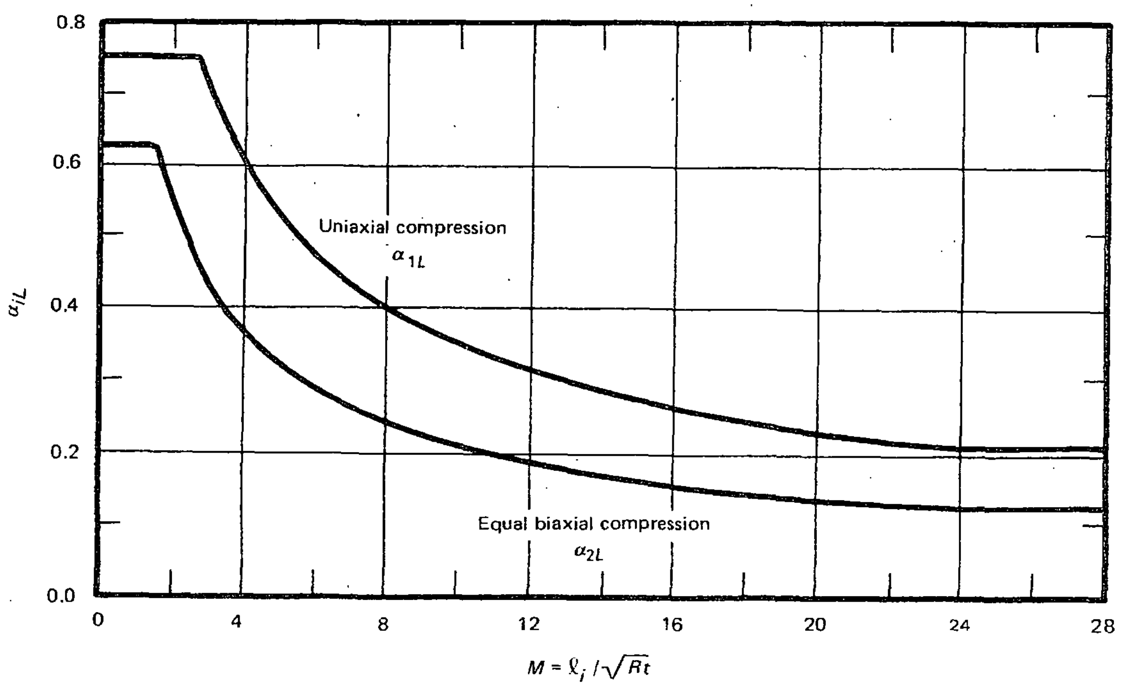



FIG. -1512-1 CAPACITY REDUCTION FACTORS FOR LOCAL BUCKLING OF STIFFENED AND UNSTIFFENED SPHERICAL SHELLS

### -1520 Stringer Buckling and General Instability

### -1521 Cylindrical Shells — Ring and/or Stringer Stiffened

*(a) Axial Compression*

$$\alpha_{\phi C} = 0.72 \qquad \text{if } \bar{A} \geq 0.20$$

$$\alpha_{\phi C} = (3.6 - 5.0\,\alpha_{\phi L})\,\bar{A} + \alpha_{\phi L} \qquad \text{if } 0.06 \leq \bar{A} < 0.20$$

$$\alpha_{\phi C} = \alpha_{\phi L} \qquad \text{if } \bar{A} < 0.06$$

where $\alpha_{\phi L}$ is determined from -1511(a)(1) and $\bar{A}$ is given by the following relationships:

$$\text{For stringers only: } \bar{A} = \frac{A_\phi}{\ell_{s\phi}}$$

$$\text{For rings only: } \bar{A} = \frac{A_\theta}{\ell_{s\theta}}$$

For rings and stringer: $\bar{A}$ = smaller of above values for $\bar{A}$.

Note: Assume that the stiffener is not effective if $\bar{A} < 0.06$.

*(b) Hoop Compression*

$$\alpha_{\theta C} = 0.80$$

*(c) Shear*

$$\alpha_{\phi\theta C} = 0.80 \text{ if } R/t \leq 250$$

$$\alpha_{\phi\theta C} = 1.323 - 0.2181\, log_{10}\,(R/t)$$

$$\text{if } 250 < R/t < 1000$$

### -1522 Spherical Shells — One-Way or Two-Way (Orthogonal) Stiffeners

*(a) Meridional Compression and/or Hoop Compression*

$$\alpha_{\phi C} = \alpha_{\theta C} = 0.1013$$

**-1523 Toroidal and Ellipsoidal Shells — One-Way or Two-Way (Orthogonal) Stiffeners.** Use the value of $\alpha_{iC}$ given for spherical shells.

## -1600 PLASTICITY REDUCTION FACTORS

The elastic buckling stresses for fabricated shells are given by the product of the classical buckling stresses and the capacity reduction factors, i.e., $\sigma_{iej}\,\alpha_{ij}$. When these values exceed the proportional limit of the fabricated material, plasticity reduction factors, $\eta_i$, are used to account for the non-linear material properties. The inelastic buckling stresses for fabricated shells are given by $\eta_i\,\sigma_{iej}\,\alpha_{ij}$.

Two sets of equations are given for determination of the plasticity reduction factors. For buckling evaluation by formulas (see -1710) the factors are expressed in terms of $\alpha_{ij}\,\sigma_{iej}$. For bifurcation buckling analysis with a computer program (see -1720 and -1730) the factors are expressed in terms of $\sigma_i\,FS$ because $\sigma_{iej}$ is an unknown quantity. This approach will always be conservative since $\sigma_i\,FS \leq \eta_i\,\alpha_{ij}\,\sigma_{iej}$.

### -1610 Factors for Buckling Analysis by Formulas (See Fig. -1610-1)

### -1611 Cylindrical Shells

Let

$$\Delta = \frac{\alpha_{ij}\,\sigma_{iej}}{\sigma_y}$$

*(a) Axial Compression*

$$\eta_\phi = 1.0 \qquad \text{if } \Delta \leq 0.55$$

$$\eta_\phi = \frac{0.45}{\Delta} + 0.18 \qquad \text{if } 0.55 < \Delta \leq 1.6$$

$$\eta_\phi = \frac{1.31}{1 + 1.15\Delta} \qquad \text{if } 1.6 < \Delta < 6.25$$

$$\eta_\phi = \frac{1}{\Delta} \qquad \text{if } \Delta \geq 6.25$$

*(b) Hoop Compression*

$$\eta_\theta = 1 \qquad \text{if } \Delta \leq 0.67$$

$$\eta_\theta = \frac{2.53}{1 + 2.29\Delta} \qquad \text{if } 0.67 < \Delta < 4.2$$

$$\eta_\theta = \frac{1}{\Delta} \qquad \text{if } \Delta \geq 4.2$$

*(c) Shear*

$$\eta_{\phi\theta} = 1.0 \qquad \text{if } \Delta \leq 0.48$$

$$\eta_{\phi\theta} = \frac{0.43}{\Delta} + 0.1 \qquad \text{if } 0.48 < \Delta < 1.7$$

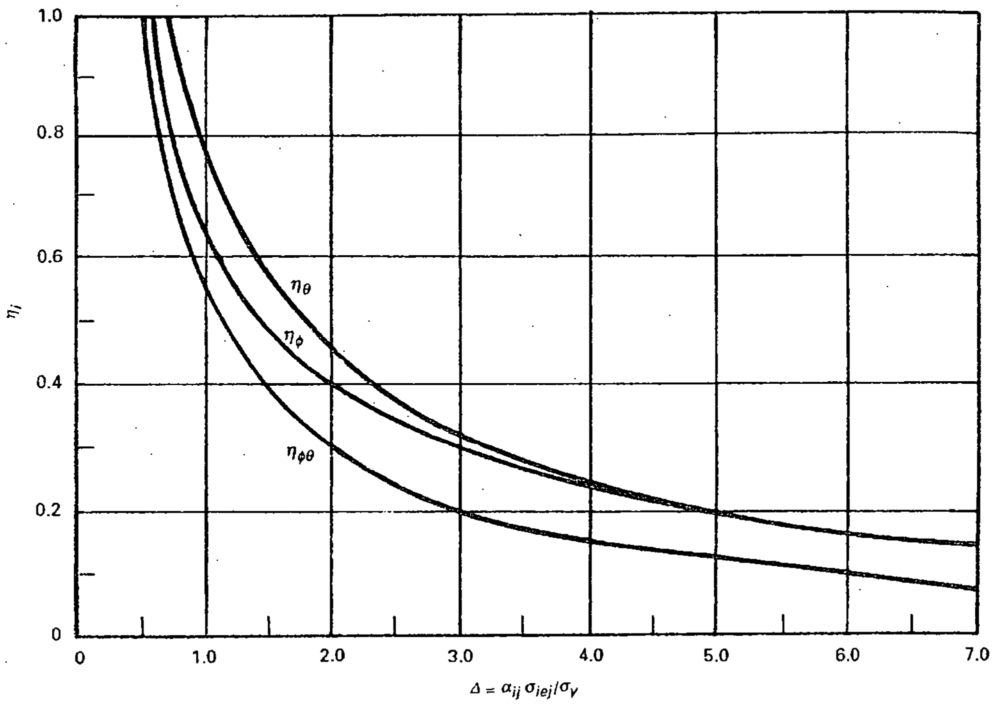



FIG. -1610-1 PLASTIC REDUCTION FACTORS FOR BUCKLING ANALYSIS BY FORMULA

$$\eta_{\phi\theta} = \frac{0.6}{\Delta} \qquad \text{if } \Delta \geq 1.7$$

### -1612 Spherical Shells

*(a) Meridional Compression and/or Hoop Compression*

Use the values given in -1611(a).

### -1613 Toroidal and Ellipsoidal Shells

*(a) Meridional Compression and/or Hoop Compression*

Use the values given in -1611(a).

### -1620 Factors for Bifurcation Buckling Analysis (See Fig. -1620-1)

If the computed values of $\sigma_\phi$ or $\sigma_\theta$ (see -1711 for methods for treatment of discontinuity stresses) exceed $\sigma_y/FS$ or $\sigma_{\phi\theta}$ exceeds 0.6 $\sigma_y/FS$, the design is inadequate and modifications are needed to lower the value of $\sigma_i$.

### -1621 Cylindrical Shells

*(a) Axial Compression*

$$\eta_\phi = 1.0 \qquad \text{if } \frac{\sigma_\phi FS}{\sigma_y} \leq 0.55$$

$$\eta_\phi = \frac{0.18}{1 - \dfrac{0.45\sigma_y}{\sigma_\phi FS}} \qquad \text{if } 0.55 < \frac{\sigma_\phi FS}{\sigma_y} \leq 0.738$$

$$\eta_\phi = 1.31 - 1.15\,\frac{\sigma_\phi FS}{\sigma_y} \qquad \text{if } 0.738 < \frac{\sigma_\phi FS}{\sigma_y} \leq 1.0$$

*(b) Hoop Compression*

$$\eta_\theta = 1 \qquad \text{if } \frac{\sigma_\theta FS}{\sigma_y} \leq 0.67$$

$$\eta_\theta = 2.53 - 2.29\,\frac{\sigma_\theta FS}{\sigma_y} \qquad \text{if } 0.67 < \frac{\sigma_\theta FS}{\sigma_y} \leq 1.0$$

*(c) Shear*

$$\eta_{\phi\theta} = 1.0 \qquad \text{if } \frac{\sigma_{\phi\theta} FS}{\sigma_y} \leq 0.48$$

$$\eta_{\phi\theta} = \frac{0.1}{1 - \dfrac{0.43\sigma_y}{\sigma_{\phi\theta} FS}} \qquad \text{if } 0.48 < \frac{\sigma_{\phi\theta} FS}{\sigma_y} \leq 0.6$$

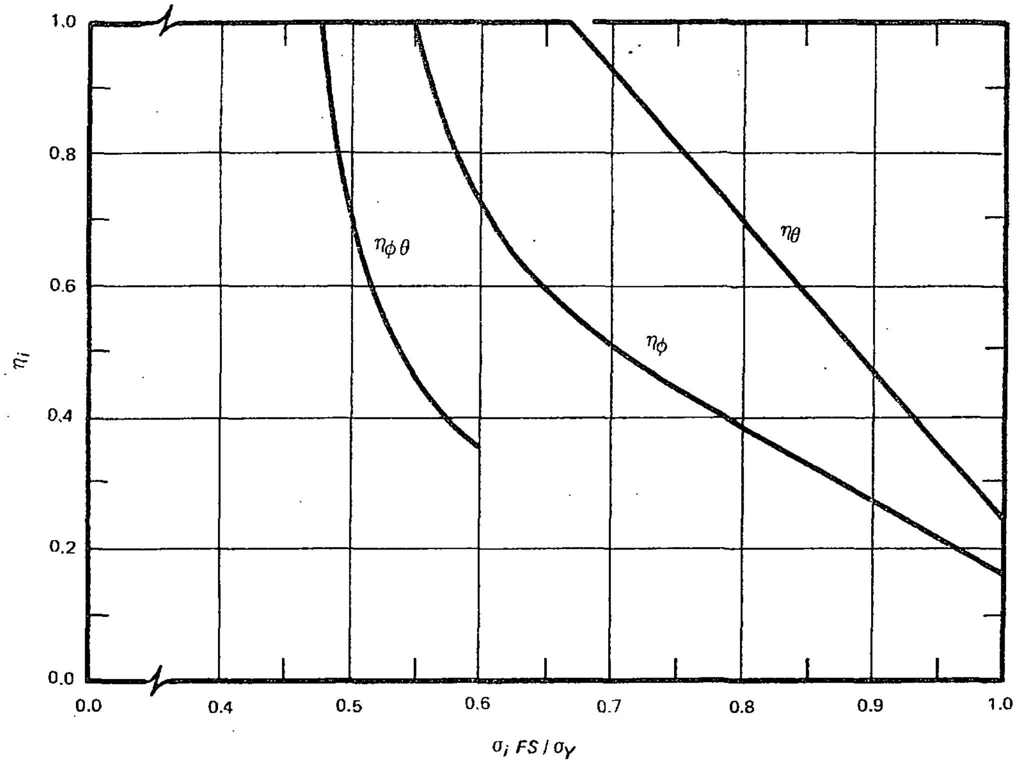



FIG. -1620-1 PLASTICITY REDUCTION FACTORS FOR BIFURCATION BUCKLING ANALYSIS

### -1622 Spherical Shells

*(a) Meridional Compression and/or Hoop Compression*

Use the values given in -1621(a).

### -1623 Toroidal and Ellipsoidal Shells

*(a) Meridional Compression and/or Hoop Compression*

Use the values given in -1621(a).

## -1700 BUCKLING EVALUATION

The buckling evaluation may be performed by one of a number of different approaches. Three acceptable alternative approaches are given in -1710, -1720, and -1730. In -1710 formulas are given for the buckling evaluation. An axisymmetric shell of revolution and a three-dimensional thin shell computer code are used for the buckling evaluations given in -1720 and -1730, respectively. Generally, the same computer program is used for both the linear elastic stress analysis, as described in -1300 and the buckling evaluation.

For each of three approaches it is recommended that a separate buckling evaluation be made for (a) local buckling of the shell plate between stiffening elements (b) buckling between circumferential stiffeners of combined shell plate and attached meridional stiffeners and (c) general instability or overall collapse of the combined shell and stiffening system. For some geometries, the critical load values predicted for the general instability mode may be significantly larger than those for the local buckling mode. This is not necessarily a good indicator of the reserve strength of the design for these geometries since actual failure may occur from excessive deformation before the predicted general instability load can be reached. A static and/or dynamic analysis is performed for each specified loading and the stresses computed in accordance with -1300. The stresses are combined for each specified Service Limit to determine the buckling stress components, $\sigma_i$.

For buckling evaluation by formula, the stress components $\sigma_i$ are inserted in the interaction equations given in -1713. Simple equations are also given in -1712 for determining the classical buckling stresses of shells for the special stress states (load cases) of axial or meridional compression alone, hydrostatic external pressure ($K = 0.5$), radial external pressure ($K = 0$), and inplane shear alone. The allowable stress values for these special stress states are given by $\sigma_{ia} = \alpha_{ij}\ \sigma_{icj}/FS$ for elastic buckling stresses and by $\sigma_{ic} = \eta_i\ \sigma_{ia}$ for inelastic buckling stresses. The allowable buckling stresses for the special stress states are used in the interaction equations in -1713 for determining the allowable stresses for combined stress states.

The classical buckling stresses may also be determined for nonuniform stress fields from the computer codes used for the methods of -1720 and -1730. Therefore, when using the values of -1500 for $\alpha_{ij}$, simply supported edges should be assumed for determination of theoretical values by computer. In this Case, the edge of the shell is assumed to be simply supported if at the edge the radial and circumferential displacements are zero and there is no restraint against rotation or translation in the meridional direction. Also there is no restraint against rotation in the circumferential direction for panels between meridional stiffeners.

For buckling evaluation by use of a computer code, amplified stress components $\sigma_{is}$ and $\sigma_{ip}$ are determined from $\sigma_{is} = \sigma_i\ FS/\alpha_{ij}$ and $\sigma_{ip} = \sigma_{is}/\eta_i$. The method of -1720 is based upon an axisymmetric shell of revolution linear bifurcation analysis. The shell model is assumed to be axisymmetric with simple support boundary conditions and the stress components $\sigma_{is}$ and $\sigma_{ip}$ are assumed to be uniformly distributed around the circumference. Each set of amplified stress components is compared with the classical buckling capacity of the shell model as discussed in -1720. If the classical buckling capacity is equal to or greater than $\lambda_c$ times the stress components, $\sigma_{is}$ and $\sigma_{ip}$, the design is adequate. A value of $\lambda_c = 1.0$ is recommended for local buckling and 1.2 for stringer buckling and general instability modes of failure.

For those cases where significant nonaxisymmetric conditions exist and a three-dimensional stress analysis has been performed, the buckling evaluation approach of -1730 may be used. For such three-dimensional thin shell buckling analysis the calculated state of stress may be used in determining the amplified stress components $\sigma_{is}$ and $\sigma_{ip}$ for input to the program.

For any of the above approaches, the effects of local discontinuities and attached masses, if not included with the general shell buckling analysis, should be investigated. For openings reinforced in accordance with the area replacement rules of Subsection NE, it can be assumed that the reduction in the buckling capacity of the shell is negligible. Stresses in the shell due to penetration loads shall be given consideration, to preclude localized buckling of the shell.

### -1710 By Formulae

**-1711 Discontinuity Stresses.** Application of certain thermal or mechanical loads may result in high local discontinuity membrane stresses. To assume that the maximum value of such localized stresses act uniformly over the entire portion of the shell under study will result in an overly conservative design. An acceptable alternative and conservative method of analysis is to use the average values of the membrane stress components within a meridional distance of $\sqrt{Rt}$ from a point of fixity or 0.5 $\sqrt{Rt}$ on each side of a discontinuity for determination of $\sigma_i$. The average stress values are to be used in calculating total stress components for performing the buckling analyses of -1713.

An acceptable alternative to the averaging method would be to caculate the uniaxial theoretical buckling stress values for the actual meridional stress distribution by use of a computer program. These more accurate values of theoretical buckling stresses can then be used for the buckling evaluation of -1713 in lieu of values calculated per -1712.

**-1712 Theoretical Buckling Values.** The buckling stresses given by the following equations correspond to the minimum values determined from theoretical equations for shells with classical simple support boundary conditions under uniform stress fields. Paragraph -1712.1 gives equations for determining the classical buckling stresses of unstiffened shells or the panels between stiffeners of stiffened shells. Paragraph 1712.2 gives equations for determining the theoretical stringer buckling and general instability stresses for stiffened shells.

Equations are presented for calculating the theoretical classical elastic bifurcation buckling values for the unique loading cases of axial compression, radial pressure, hydrostatic pressure, and shear. In addition to their use in predicting buckling for these conditions, the values are also used in the interaction equations of -1713 for combined loading cases. The subscripts $r$ and $h$ denote radial and hydrostatic loading cases, respectively.

**-1712.1 Local Buckling**

**-1712.1.1 Cylindrical Shells — Unstiffened and Ring Stiffened (See Fig. -1712.1.1-1)**

*(a) Axial Compression*

$$\sigma_{\phi eL} = C_\phi Et/R$$

$$C_\phi = 0.630 \qquad \text{if } M_\phi \le 1.5$$

$$C_\phi = \frac{0.904}{M_\phi^2} + 0.1013M_\phi^2 \qquad \text{if } 1.5 < M_\phi < 1.73$$

$$C_\phi = 0.605 \qquad \text{if } M_\phi \ge 1.73$$

*(b) External Pressure*

*(1)* No End Pressure ($K = 0$)

$$\sigma_{\theta eL} = \sigma_{reL} = C_{\theta r} Et/R$$

$$C_{\theta r} = 1.616 \qquad \text{if } M_\phi \le 1.5$$

$$C_{\theta r} = \frac{2.41}{M_\phi^{1.49} - 0.338} \qquad \text{if } 1.5 < M_\phi < 3.0$$

$$C_{\theta r} = \frac{0.92}{M_\phi - 1.17} \qquad \text{if } 3.0 \le M_\phi < 1.65\frac{R}{t}$$

$$C_{\theta r} = 0.275\frac{t}{R} + \frac{2.1}{M_\phi^4}\left(\frac{R}{t}\right)^3 \qquad \text{if } M_\phi \ge 1.65\frac{R}{t}$$

*(2)* End Pressure Included ($K = 0.5$)

$$\sigma_{\theta eL} = \sigma_{heL} = C_{\theta h} E\frac{t}{R}$$

$$C_{\theta h} = 0.988 \qquad \text{if } M_\phi \le 1.5$$

$$C_{\theta h} = \frac{1.08}{M_\phi^{1.07} - 0.45} \qquad \text{if } 1.5 < M_\phi < 3.5$$

$$C_{\theta h} = \frac{0.92}{M_\phi - 0.636} \qquad \text{if } 3.5 \le M_\phi < 1.65\frac{R}{t}$$

$$C_{\theta h} = 0.275\frac{t}{R} + \frac{2.1}{M_\phi^4}\left(\frac{R}{t}\right)^3 \qquad \text{if } M_\phi \ge 1.65\frac{R}{t}$$

*(c) Shear*

$$\sigma_{\phi\theta eL} = C_{\phi\theta}Et/R$$

$$C_{\phi\theta} = 2.227 \qquad \text{if } M_\phi \le 1.5$$

$$C_{\phi\theta} = \frac{4.82}{M_\phi^2}(1 + 0.0239M_\phi^3)^{1/2} \qquad \text{if } 1.5 < M_\phi < 26$$

$$C_{\phi\theta} = \frac{0.746}{\sqrt{M_\phi}} \qquad \text{if } 26 \le M_\phi < 8.69\frac{R}{t}$$

$$C_{\phi\theta} = 0.253\left(\frac{t}{R}\right)^{1/2} \qquad \text{if } M_\phi \ge 8.69\frac{R}{t}$$

**-1712.1.2 Cylindrical Shells — Stringer Stiffened or Ring and Stringer Stiffened**

*(a) Axial Compression* (See Fig. -1712.1.1-1)

The following equation applies when $M_\theta < 2M_\phi$; otherwise use the equation given in -1712.1.1(a).

$$\sigma_{\phi eL} = C_\phi Et/R$$

$$C_\phi = 1.666 \qquad \text{if } M_\phi \le 1.5$$

$$C_\phi = \frac{3.62}{M_\phi^2} + 0.0253M_\phi^2 \qquad \text{if } 1.5 < M_\phi < 3.46$$

$$C_\phi = 0.605 \qquad \text{if } M_\phi \ge 3.46$$

*(b) External Pressure*

The following equations apply when $M_\theta < 1.15\sqrt{M_\phi}$; otherwise use the equations given in -1712.1.1(b).

$$n^2 = (\pi R/\ell_\theta)^2$$

*(1)* No End Pressure ($K = 0$)

$$\sigma_{\theta eL} = \sigma_{reL} = C_{\theta r} Et/R$$

$$C_{\theta r} = \frac{1}{n^2 - 1}\left[\frac{(n^2 + \lambda^2 - 1)^2}{10.92}\left(\frac{t}{R}\right) + \frac{\lambda^4}{(n^2 + \lambda^2)^2}\left(\frac{R}{t}\right)\right]$$

*(2)* End Pressure Included ($K = 0.5$)

$$\sigma_{\theta eL} = \sigma_{heL} = C_{\theta h} Et/R$$

$$C_{\theta h} = \frac{1}{n^2 + 0.5\,\lambda^2 - 1}\left[\frac{(n^2 + \lambda^2 - 1)^2}{10.92}\left(\frac{t}{R}\right) + \frac{\lambda^4}{(n^2 + \lambda^2)^2}\left(\frac{R}{t}\right)\right]$$

*(c) Shear* (See Fig. -1712.1.2-1

The following equations apply when $M < 26$ and $a/b \le 3.0$, where $a$ = greater of $\ell_\phi$ and $\ell_\theta$ and $b$ = smaller of $\ell_\phi$ and $\ell_\theta$ and $M = b/\sqrt{Rt}$; otherwise use the equations given in -1712.1.1(c).

$$\sigma_{\phi\theta eL} = C_{\phi\theta} Et/R$$

$$C_{\phi\theta} = \frac{1}{M^2}\left[4.82\,(1 + 0.0239M^3)^{1/2} + 3.62\left(\frac{b}{a}\right)^2\right]$$

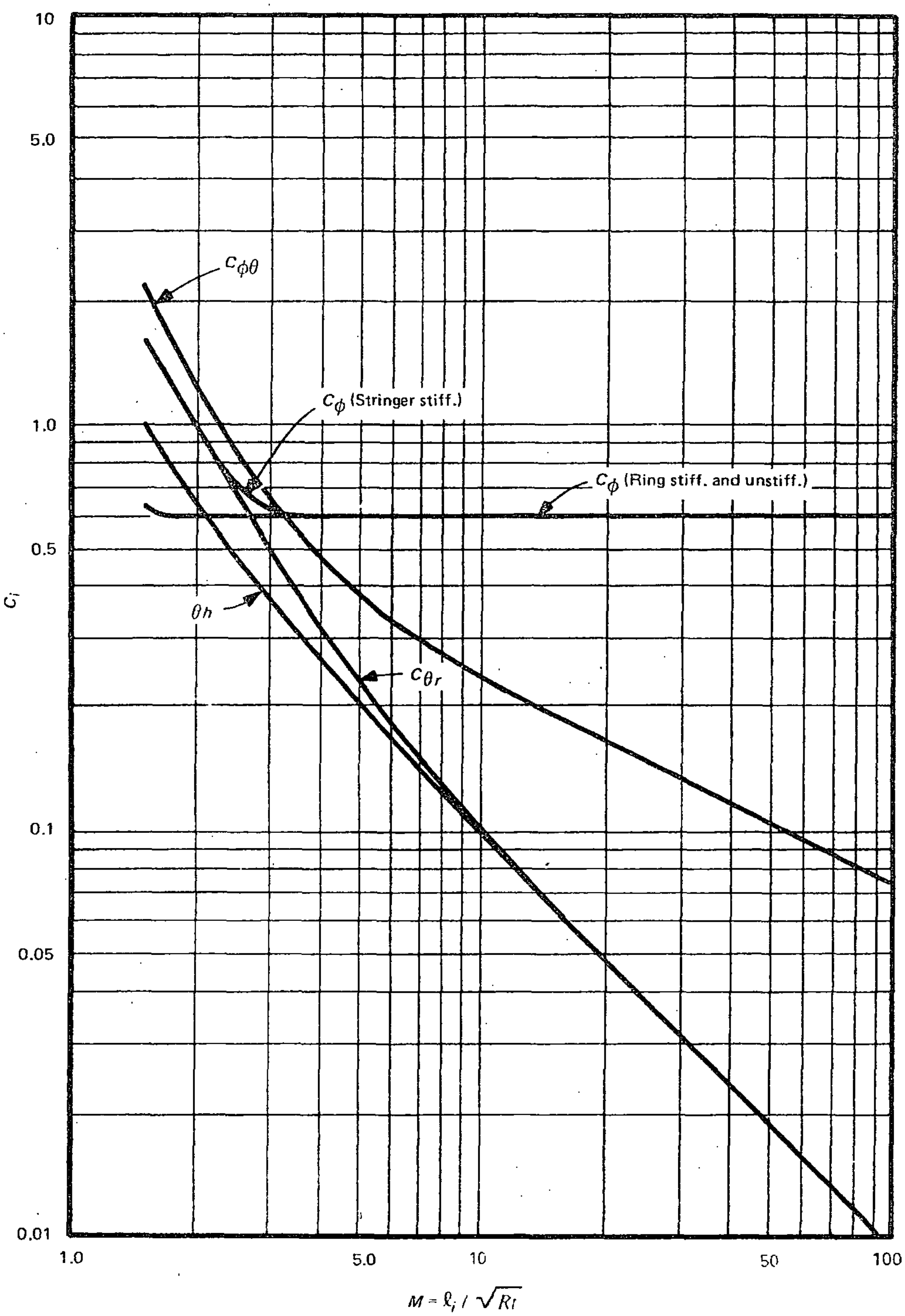



FIG. -1712.1.1-1 THEORETICAL LOCAL BUCKLING STRESS COEFFICIENTS FOR STIFFENED AND UNSTIFFENED CYLINDRICAL SHELLS

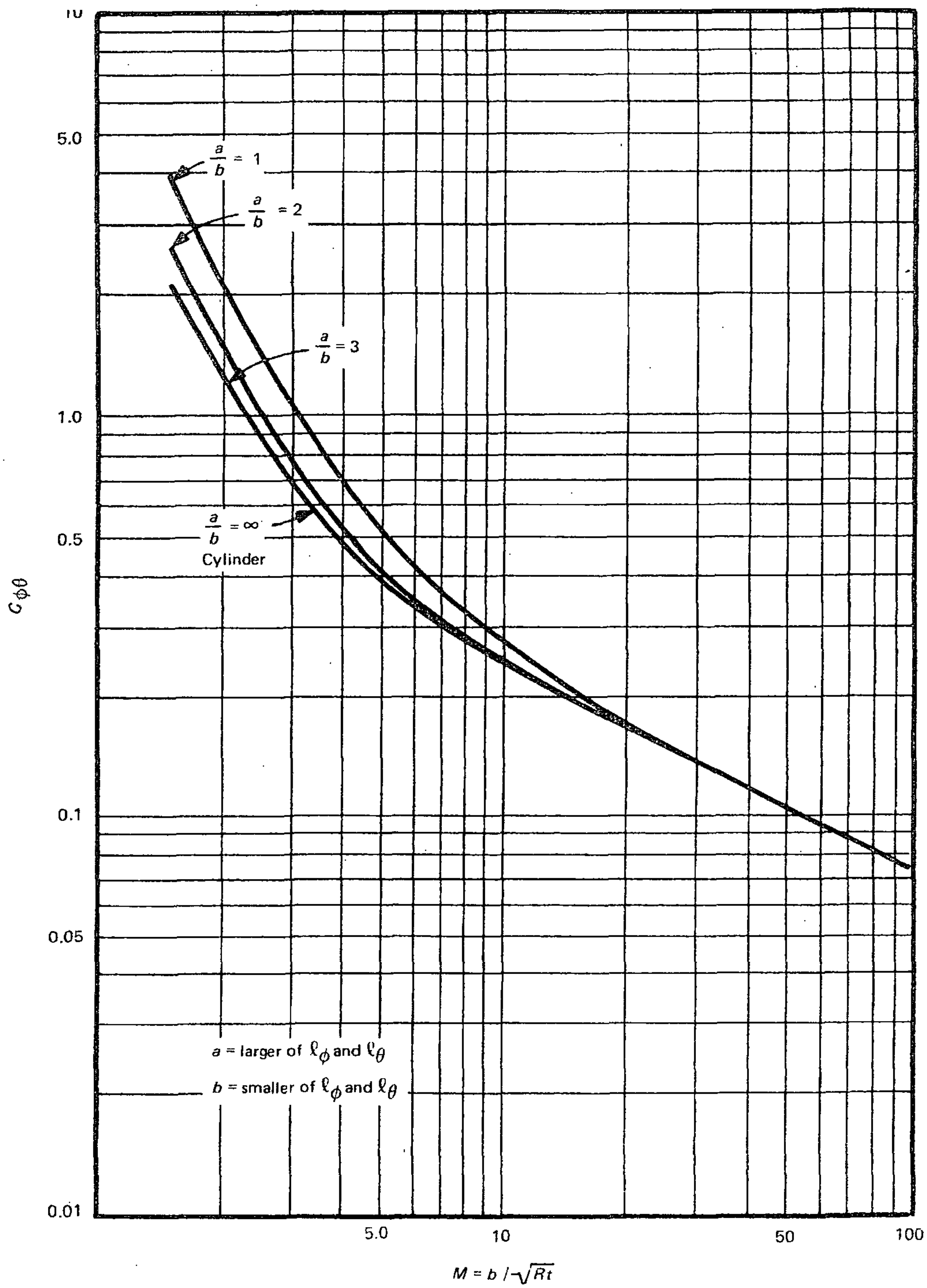



FIG. -1712.1.2-1 THEORETICAL LOCAL BUCKLING STRESS COEFFICIENTS FOR STRINGER STIFFENED CYLINDER SUBJECTED TO IN-PLANE SHEAR

**-1712.1.3 Spherical Shells — Stiffened or Unstiffened**

*(a) Equal Biaxial Compressive Stress*

[Equations are the same as -1712.1.1(a)].

$$\sigma_{\phi eL} = \sigma_{\theta eL} = C\,Et/R$$

$$C = 0.630 \qquad \text{if } M \leq 1.5$$

$$= \frac{0.904}{M^2} + 0.1013M^2 \qquad \text{if } 1.5 < M < 1.73$$

$$C = 0.605 \qquad \text{if } M \geq 1.73$$

*(b) Unequal Biaxial Compressive Stress*

Not used in interaction relationships of -1713.

*(c) Shear*

When shear is present, the principal stresses will be calculated and substituted for $\sigma_\phi$ and $\sigma_\theta$ in the buckling equations.

**-1712.1.4 Toroidal and Ellipsoidal Shells — Stiffened or Unstiffened**

Toroidal and ellipsoidal shells shall be analyzed as equivalent spheres.

**-1712.2 Stringer Buckling and General Instability**

**-1712.2.1 Cylindrical Shells — Ring Stiffened**

*(a) Axial Compression*

$$\sigma_{\phi eG} = 0.605E\,\frac{t}{R}\left(1 + \frac{A_\theta}{\ell_\phi t}\right)^{1/2}$$

*(b) External Pressure*

Determine the value of $n$ which minimizes $\sigma_{\theta eG}$ in the equations which follow.

*(1)* No End Pressure ($K = 0$)

$$\sigma_{\theta eG} = \frac{E\bar{\lambda}^4}{(n^2 - 1)(n^2 + \bar{\lambda}^2)^2} + \frac{EI_{E\theta}\,(n^2 - 1)}{\ell_\phi R_c^2 t}$$

*(2)* End Pressure Included ($K = 0.5$)

$$\sigma_{\theta eG} = \frac{E\bar{\lambda}^4}{(n^2 + 0.5\,\bar{\lambda}^2 - 1)(n^2 + \bar{\lambda}^2)^2} + \frac{EI_{E\theta}\,(n^2 - 1)}{\ell_\phi R_c^2 t}$$

*(c) Shear*

$$\sigma_{\phi\theta eG} = \frac{3.46E}{L_B^{1/2} R^{3/4}}\left(\frac{I_{E\theta}}{\ell_\phi t}\right)^{5/8}$$

**-1712.2.2 Cylindrical Shells — Stringer Stiffened or Ring and Stringer Stiffened**

The theoretical elastic buckling stresses for both stringer buckling and general instability are given by the equations which follow. Stringer buckling is defined as the buckling between rings of the stringer and attached plate and general instability is defined as the buckling mode in which the rings and attached plate deform radially.

The elastic buckling stress is denoted $\sigma_{iej}$ where $i$ is the stress direction and $j$ is the buckling mode; $j = S$ for stringer buckling and $j = G$ for general instability. The stringer buckling stress is determined by letting the cylinder length equal the ring spacing, $L_j = \ell_\phi$ and the general instability stress by letting $L_j = L_B$.

The values of $m$ and $n$ to use in the following equations are those which minimize $\sigma_{iej}$ where $m \geq 1$ and $n > 2$. The following values are to be used for $\ell_{e\phi}$ and $\ell_{e\theta}$. When $\ell_{e\phi} < \ell_\phi$ or $\ell_{e\theta} < \ell_\theta$, set $\mu = 0$.

*(a) Axial Compression*

$$\ell_{e\phi} = \ell_\phi$$

$$\ell_{e\theta} = \ell_\theta \qquad \text{if } \ell_\theta \leq 1.288tQ$$

$$\ell_{e\theta} = 1.9tQ\left(1 - \frac{0.415tQ}{\ell_\theta}\right) \qquad \text{if } \ell_\theta > 1.288tQ\,.$$

where

$$Q = \sqrt{\frac{E}{\sigma_{\phi ej}\,\alpha_{\phi G}}} \geq \sqrt{\frac{E}{\sigma_y}}$$

For stringer buckling:

$$j = S,\ A_\theta = I_\theta = J_\theta = 0,\ t_\theta = t,\ L_j = \ell_\phi$$

For general instability:

$$j = G,\ L_j = L_B$$

See -1521(a) for $\alpha_{\phi G}$ and the equation below for $\sigma_{\phi ej}$. When $\ell_{e\theta} < \ell_\theta$, the values for $\sigma_{\phi ej}$ must be determined by iteration since the effective width is a function of the buckling stress.

$$\sigma_{\phi ej} = \frac{A_{33} + \left(\dfrac{A_{12}A_{23} - A_{13}A_{22}}{A_{11}A_{22} - A_{12}^2}\right)A_{13} + \left(\dfrac{A_{12}A_{13} - A_{11}A_{23}}{A_{11}A_{22} - A_{12}^2}\right)A_{23}}{\left(\dfrac{m\pi}{L_j}\right)^2 t_\phi}$$

where

$$A_{11} = E_\phi \left(\frac{m\pi}{L_j}\right)^2 + G_{\phi\theta}\left(\frac{n}{R}\right)^2$$

$$A_{22} = E_\theta \left(\frac{n}{R}\right)^2 + G_{\phi\theta}\left(\frac{n\pi}{L_j}\right)^2$$

$$A_{33} = D_\phi \left(\frac{m\pi}{L_j}\right)^4 + \overline{D}_{\phi\theta}\left(\frac{m\pi}{L_j}\right)^2\left(\frac{n}{R}\right)^2 + D_\theta\left(\frac{n}{R}\right)^4 +$$

$$\frac{E_\theta}{R^2} + \frac{2C_\theta}{R}\left(\frac{n}{R}\right)^2$$

$$A_{12} = (E_{\phi\theta} + G_{\phi\theta})\left(\frac{m\pi}{L_j}\right)\left(\frac{n}{R}\right)$$

$$A_{23} = \frac{E_\theta}{R}\left(\frac{n}{R}\right) + C_\theta\left(\frac{n}{R}\right)^3$$

$$A_{13} = \frac{E_{\phi\theta}}{R}\left(\frac{m\pi}{L_j}\right) + C_\phi\left(\frac{m\pi}{L_j}\right)^3$$

$$E_\phi = \frac{Et}{1-\mu^2}\left(\frac{\ell_{e\theta}}{\ell_\theta}\right) + \frac{EA_\phi}{\ell_\theta} \quad E_{\phi\theta} = \frac{\mu Et}{1-\mu^2}$$

$$E_\theta = \frac{Et}{1-\mu^2}\left(\frac{\ell_{e\phi}}{\ell_\phi}\right) + \frac{EA_\theta}{\ell_\phi} \quad G_{\phi\theta} = \frac{Gt}{2}\left(\frac{\ell_{e\phi}}{\ell_\phi} + \frac{\ell_{e\theta}}{\ell_\theta}\right)$$

$$D_\phi = \frac{Et^3}{12\,(1-\mu^2)}\left(\frac{\ell_{e\theta}}{\ell_\theta}\right) + \frac{EI_\phi}{\ell_\theta} + \frac{EA_\phi Z_\phi^2}{\ell_\theta}$$

$$D_\theta = \frac{Et^3}{12\,(1-\mu^2)}\left(\frac{\ell_{e\phi}}{\ell_\phi}\right) + \frac{EI_\theta}{\ell_\phi} + \frac{EA_\theta Z_\theta^2}{\ell_\phi}$$

$$\overline{D}_{\phi\theta} = \frac{\mu Et^3}{6\,(1-\mu^2)} + \frac{Gt^3}{6}\left(\frac{\ell_{e\phi}}{\ell_\phi} + \frac{\ell_{e\theta}}{\ell_\theta}\right) + \frac{GJ_\phi}{\ell_\theta} + \frac{GJ_\theta}{\ell_\phi}$$

$$C_\phi = \frac{EA_\phi Z_\phi}{\ell_\theta} \quad C_\theta = \frac{EA_\theta Z_\theta}{\ell_\phi}$$

*(b) External Pressure*

Stringer Buckling ($j = S$)

$$\ell_{e\phi} = 1.56\sqrt{Rt} \text{ but not greater than } \ell_\phi$$

$$\ell_{e\theta} = \ell_\theta$$

$$A_\theta = I_\theta = J_\theta = 0,\ t_\theta = t,\ L_j = \ell_\phi$$

General Instability ($j = G$)

$$\ell_{e\phi} = 1.56\sqrt{Rt} \text{ but not greater than } \ell_\phi$$

$$\ell_{e\theta} = \ell_\theta,\ L_j = L_B$$

$$\sigma_{\theta ej} = \frac{A_{33} + \left(\dfrac{A_{12}A_{23} - A_{13}A_{22}}{A_{11}A_{22} - A_{12}^2}\right)A_{13} + \left(\dfrac{A_{12}A_{13} - A_{11}A_{23}}{A_{11}A_{22} - A_{12}^2}\right)A_{23}}{\left[K\left(\dfrac{m\pi}{L_j}\right)^2 + \left(\dfrac{n}{R}\right)^2\right]t_\theta}$$

where

$A_{xy}$ = values given in (a) above.

*(c) Shear*

$$\sigma_{\phi\theta eG} = \frac{3.46Et_\phi^{3/8}}{L_B^{1/2}R^{3/4}t_{\phi\theta}}\left(\frac{I_{E\theta}}{\ell_{s\phi}}\right)^{5/8}$$

**-1712.2.3 Spherical Shells — One-Way or Two-Way (Orthogonal) Stiffeners**

*(a) Equal Biaxial Compressive Stress*

$$\sigma_{\phi eG} = \sigma_{\theta eG} = \frac{2.00Et_1^{1/4}}{Rt_2^{3/4}}\left(\frac{I_{E1}}{\ell_{s2}}\right)^{1/3}\left(\frac{I_{E2}}{\ell_{s1}}\right)^{1/6}$$

Subscripts 1 and 2 correspond to $\phi$ and $\theta$ where $I_{E1} \geq I_{E2}$ and $t_1 \geq t_2$. For one-way stiffening $I_{E2} = \ell_{s1}\, t^3/12$.

**-1712.2.4 Toroidal and Ellipsoidal Shells — Meridional and/or Circumferential Stiffeners.** Toroidal and ellipsoidal shells may be analyzed as equivalent spheres.

**-1713 Interaction Equations for Local Buckling.** The equations which follow can be used to evaluate the local buckling capacity of the shell. The form of such interaction relationships depends on whether the critical stresses are in the elastic or inelastic range. If any of the uniaxial critical stress values exceed the proportional limit of the fabricated material, the inelastic interaction relationships of -1713.2 should be satisfied in addition to the elastic interaction relationships of -1713.1. If the calculated meridional or hoop stress is tension, it should be assumed zero for the interaction evaluation. An increase in the critical axial compressive stress due to hoop tension may be included in the analysis, if justified in the Design Report. Methods for treatment of discontinuity stresses are given in -1711.

The theoretical buckling values can be determined from -1712.1 or from a computer program by the procedures given in -1700 and -1711. If the relationships of -1713.1 and -1713.2 are satisfied, the design is adequate to prevent local buckling.

The buckling capacities for the stringer buckling and general instability modes can be determined in a similar manner by substituting the capacity reduction factors and theoretical buckling values for these modes into the interaction equations. This Code Case recommends that the buckling capacity for these modes be 20% greater than for the local buckling mode. This is accomplished by changing the right-hand side of the interaction equations to 1.2 rather than 1.0. An acceptable alternative is to determine the stiffener sizes by the equations given in -1714. This method will be more conservative.

**-1713.1 Elastic Buckling.** The relationships in the following paragraphs must be satisfied.

**-1713.1.1 Cylindrical Shells.** The allowable stresses for the special load cases of axial (meridional) compression alone, hydrostatic external pressure, radial external pressue, and in-plane shear alone are given by

$$\sigma_{xa} = \frac{\alpha_{\phi L}\sigma_{\phi eL}}{FS},\ \sigma_{ha} = \frac{\alpha_{\theta L}\sigma_{heL}}{FS},$$

$$\sigma_{ra} = \frac{\alpha_{\theta L}\sigma_{reL}}{FS},\ \text{and}\ \sigma_{\tau a} = \frac{\alpha_{\phi\theta}\sigma_{\phi\theta eL}}{FS}$$

These stresses are used in the interaction equations which follow for combined stress states. The allowable stresses can be determined, if desired, for any stress by letting $\sigma_\phi = \sigma_\theta\ Kt_\theta/t_\phi$. The resulting values for $\sigma_\phi$, $\sigma_\theta$, and $\sigma_{\phi\theta}$ are allowable stress values $\sigma_{\phi a}$, $\sigma_{\theta a}$, and $\sigma_{\phi\theta a}$. The allowable stresses are given by these equations when the expressions on the left are equal to 1.0 for local buckling and 1.2 for stringer buckling and general instability. For further explanation of the interaction equations see Fig. -1713.1-1.

See -1400, -1511, and -1712.1.1 for $FS$, $\alpha_{iL}$, and $\sigma_{ieL}$, respectively. Alternatively, $\sigma_{ieL}$ may be determined by a computer program using the procedure given in -1700 and -1711.

*(a) Axial Compression Plus Hoop Compression* ($K < 0.5$).

No interaction check is required if $\sigma_\theta < \sigma_{ha}$

$$\frac{\sigma_\theta}{\sigma_{ra} - 2\sigma_\phi\left(\dfrac{\sigma_{ra}}{\sigma_{ha}} - 1\right)\dfrac{t_\phi}{t_c}} \le 1.0$$

*(b) Axial Compression Plus Hoop Compression* ($K \ge 0.5$.)

No interaction check is required if $\sigma_\phi \le 0.5\sigma_{ha}\ t_\theta/t_\phi$.

$$\frac{\sigma_\phi - 0.5\ \sigma_{ha}\ t_\theta/t_\phi}{\sigma_{xa} - 0.5\ \sigma_{ha}\ t_\theta/t_\phi} + \left(\frac{\sigma_\theta}{\sigma_{ha}}\right)^2 \le 1.0$$

*(c) Axial Compression Plus Shear*

$$\frac{\sigma_\phi}{\sigma_{xa}} + \left(\frac{\sigma_{\phi\theta}}{\sigma_{\tau a}}\right)^2 \le 1.0$$

*(d) Hoop Compression Plus In-Plane Shear*

$$\frac{\sigma_\theta}{\sigma_{ra}} + \left(\frac{\sigma_{\phi\theta}}{\sigma_{\tau a}}\right)^2 \le 1.0$$

*(e) Axial Compression Plus Hoop Compression Plus In-Plane Shear*

For a given shear ratio ($\sigma_{\phi\theta}/\sigma_{\tau a}$) determine the value for $K_s$ from the following equation:

$$K_s = 1 - \left(\frac{\sigma_{\phi\theta}}{\sigma_{\tau a}}\right)^2$$

and substitute the values of $K_s\ \sigma_{xa}$, $K_s\ \sigma_{ra}$ and $K_s\ \sigma_{ha}$ for $\sigma_{xa}$, $\sigma_{ra}$ and $\sigma_{ha}$, respectively, in the equations given in (a) or (b) above.

**-1713.1.2 Spherical Shells.** The allowable stresses for the special load cases of uniaxial compression and uniform external pressure are given by the equations which follow and are used in the interaction equation for other biaxial compression stress states. If one stress component is in tension, the tensile stress may be set to zero and the shell considered as a uniaxial compression case.

$$\sigma_{1a} = \frac{\alpha_{1L}\sigma_{\phi eL}}{FS}\ \text{and}\ \sigma_{2a} = \frac{\alpha_{2L}\sigma_{\phi eL}}{FS}$$

where

$FS$ = see -1400

$\alpha_{1L}$ = see -1512(a)

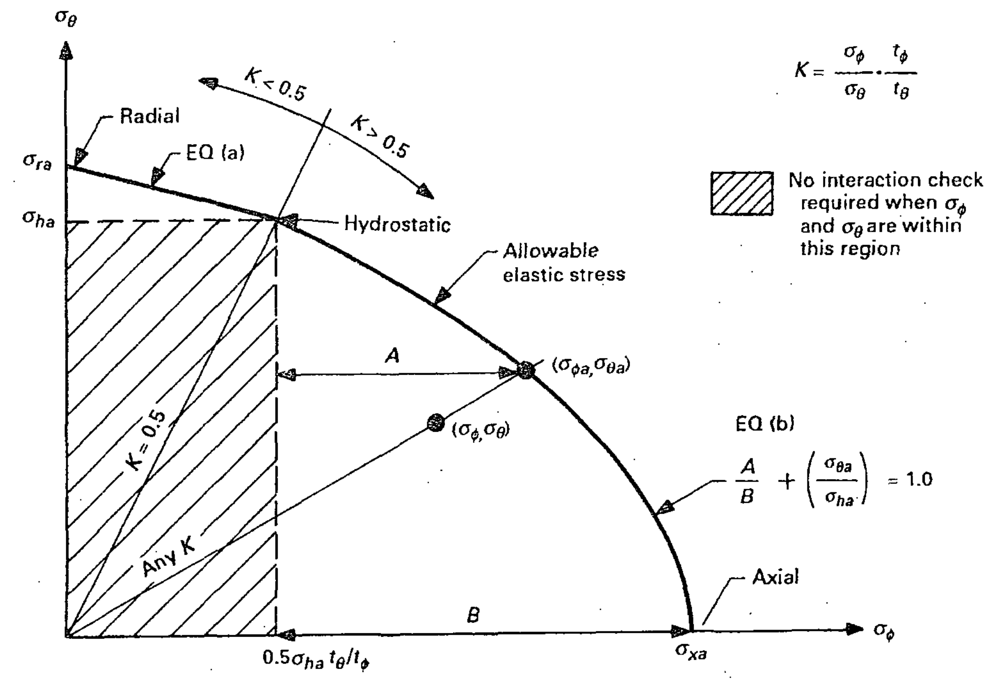
$\alpha_{2L}$ = see -1512(b)

and

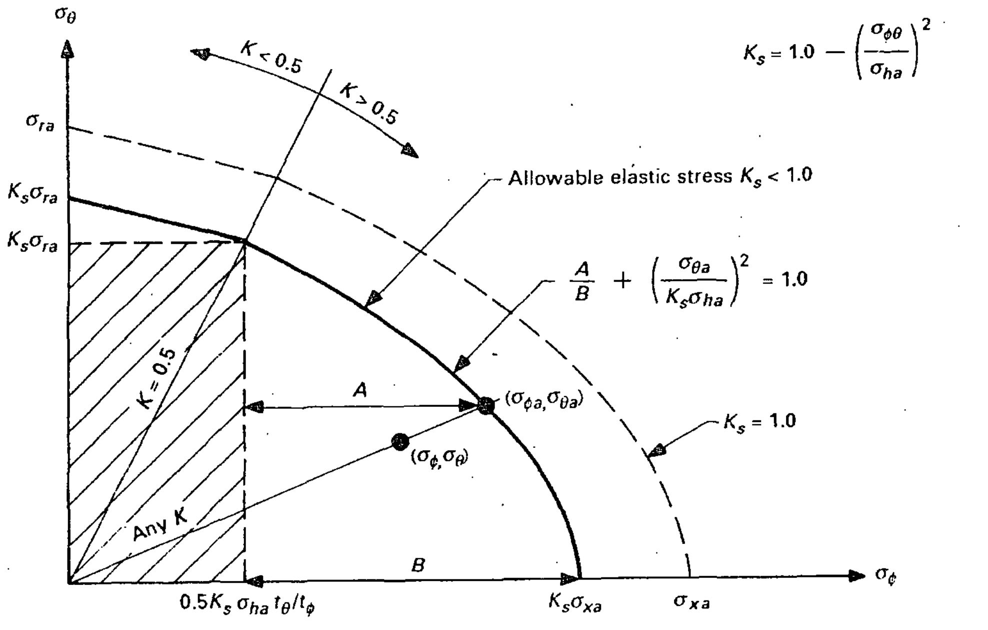
$\sigma_{\phi eL}$ = see -1712.1.3. The length $\ell_\phi$ to use for calculating $M$ is equal to the diameter of the largest circle which can be inscribed within the lines of support. The length is to be measured along the arc.

When $\sigma_{\phi\theta} \neq 0$, determine the principal stresses corresponding to stress components $\sigma_i$ and substitute for $\sigma_\phi$ and $\sigma_\theta$ in the expressions below for $\sigma_1$ and $\sigma_2$.

$\sigma_1$ = larger compression stress of $\sigma_\phi$ and $\sigma_\theta$




(a) Axial Compression Plus Hoop Compression




(b) Axial Compression Plus Hoop Compression Plus In-Plane Shear

FIG. -1713.1-1 INTERACTION CURVES FOR ELASTIC BUCKLING OF CYLINDERS UNDER COMBINED LOADS

$\sigma_2$ = smaller compression stress of $\sigma_\phi$ and $\sigma_\theta$

*(a) Uniaxial Compression*

$$\frac{\sigma_1}{\sigma_{1a}} \le 1.0$$

*(b) Biaxial Compression*

$$\frac{\sigma_1 - \sigma_2}{\sigma_{1a}} + \frac{\sigma_2}{\sigma_{2a}} \le 1.0$$

**-1713.1.3 Toroidal and Ellipsoidal Shells.** The allowable stresses for the special stress states of uniaxial compression and equal biaxial compression are given by the equations which follow and these values are used in the interaction equation for other stress states.

$$\sigma_{1a} = \frac{\alpha_{1L}\sigma_{1eL}}{FS} \text{ and } \sigma_{2a} = \frac{\alpha_{2L}\sigma_{2eL}}{FS}$$

where $FS$, $\alpha_{1L}$, $\alpha_{2L}$, and $\sigma_{\phi eL}$ are defined in -1713.1.2. Calculate $\sigma_{1eL}$, and $\sigma_{2eL}$ from the following procedure. See Fig. -1713.1.3-1 for $R_1$ and $R_2$.

$\sigma_{1eL} = \sigma_{\phi eL}$ = theoretical buckling stress for sphere under equal biaxial stress based on $R$ associated with $\sigma_1$. $R = R_1$ if $\sigma_1 = \sigma_\theta$ and $R = R_2$ if $\sigma_1 = \sigma_\phi$.

$\sigma_{2eL} = \sigma_{\phi eL}$ = theoretical buckling stress for sphere under equal biaxial stress based on $R$ associated with $\sigma_2$. $R = R_1$ of $\sigma_2 = \sigma_\theta$ and $R = R_2$ if $\sigma_2 = \sigma_\phi$.

When $\sigma_{\phi\theta} \ne 0$, determine the principal stresses corresponding to the stress components $\sigma_i$ and substitute for $\sigma_\phi$ and $\sigma_\theta$ in the expressions for $\sigma_1$ and $\sigma_2$ given in -1713.1.2.

Also determine radii $R_1$ and $R_2$ which correspond to the principal stress directions.

*(a) Uniaxial Compression.* See -1713.1.2(a)

*(b) Biaxial Compression.* See -1713.1.2(b)

**-1713.2 Inelastic Buckling.** The relationships in the following paragraphs must also be satisfied when any of the values of $\eta_i < 1$. No interaction equations are given for meridional compression plus hoop compression because it is conservative to ignore interaction of the two stress components when buckling is inelastic. See Fig. -1713.2-1.

**-1713.2.1 Cylindrical Shells.** The allowable stresses for the special stress states of axial compression alone, radial external pressure and inplane shear alone are given by:

$$\sigma_{xc} = \eta_\phi \sigma_{xa}, \ \sigma_{rc} = \eta_\theta \sigma_{ra} \text{ and } \sigma_{\tau c} = \eta_{\phi\theta}\sigma_{\tau a}$$

See -1610 for $\eta_i$ and -1713.1.1 for $\sigma_{ia}$.

*(a) Axial Compression or Hoop Compression*

$$\frac{\sigma_\phi}{\sigma_{xc}} \le 1.0, \ \frac{\sigma_\theta}{\sigma_{rc}} \le 1.0$$

*(b) Axial Compression Plus Shear*

$$\frac{\sigma_\theta}{\sigma_{xc}} + \left(\frac{\sigma_{\phi\theta}}{\sigma_{\tau c}}\right)^2 \le 1.0$$

*(c) Hoop Compression Plus Shear*

$$\frac{\sigma_\theta}{\sigma_{rc}} + \left(\frac{\sigma_{\phi\theta}}{\sigma_{\tau c}}\right)^2 \le 1.0$$

**-1713.2.2 Spherical Shells.** In the equation which follows:

$$\sigma_{1c} = \eta_\phi \sigma_{1a}$$

where $\eta_\phi$ corresponds to stress $\sigma_{1a}$ $FS$. See -1713.1.2 for $\sigma_1$ and $\sigma_{1a}$ and -1612 for $\eta_\phi$.

*(a) Uniaxial or Biaxial Compression*

$$\sigma_1 \le \sigma_{1c}$$

**-1713.2.3 Toroidal and Ellipsoidal Shells.** In the equations which follow:

$$\sigma_{1c} = \eta_1 \sigma_{1a} \text{ and } \sigma_{2c} = \eta_2 \sigma_{2a}$$

where $\eta_1$ corresponds to stress $\sigma_{1a}$ $FS$ and $\eta_2$ corresponds to stress $\sigma_{2a}$ $FS$. See -1713.1.3 for $\sigma_1$, $\sigma_2$, $\sigma_{1a}$, $\sigma_{2a}$ and -1613 for $\eta_1$ and $\eta_2$.

*(a) Uniaxial Compression Plus Shear*

$$\sigma_1 \le \sigma_{1c}$$

*(b) Biaxial Compression Plus Shear*

The following two relationships must be satisfied.

$$\sigma_1 \le \sigma_{1c}$$

$$\sigma_2 \le \sigma_{2c}$$

**-1714 Sizing of Stiffeners.** The size of stiffeners required to prevent stringer buckling and general instability failures can be determined from the interaction equations given in -1713 by using the appropriate values

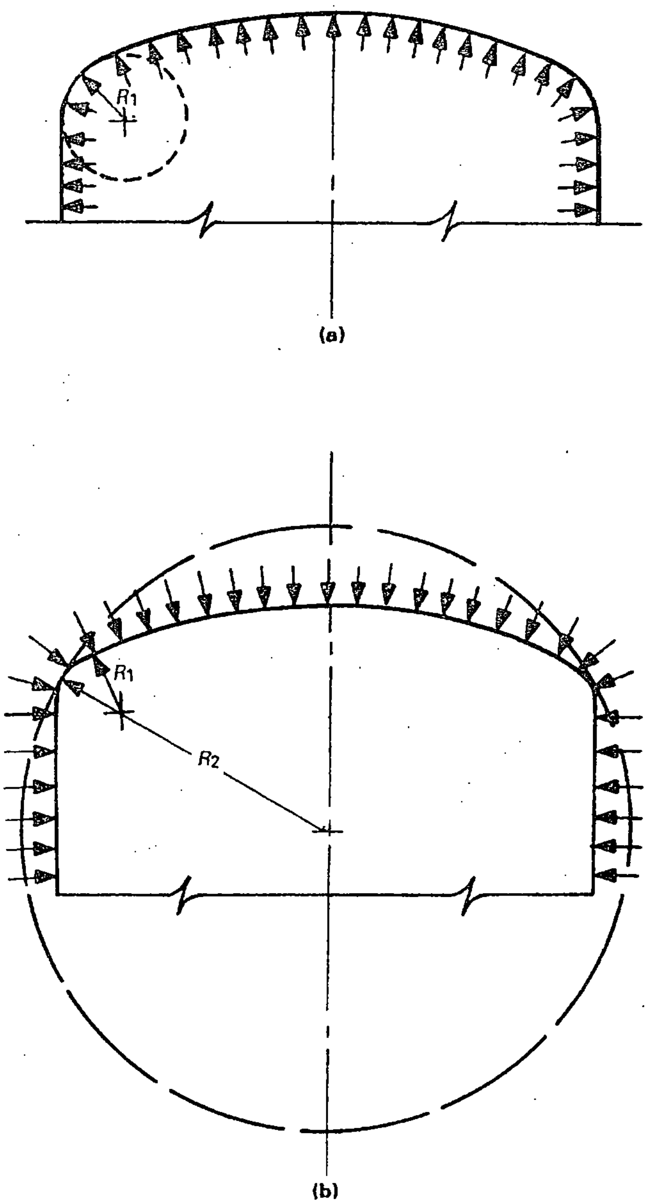
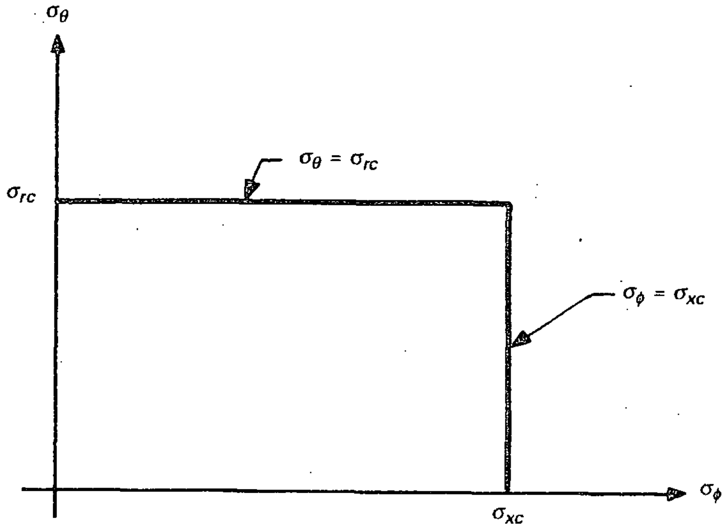
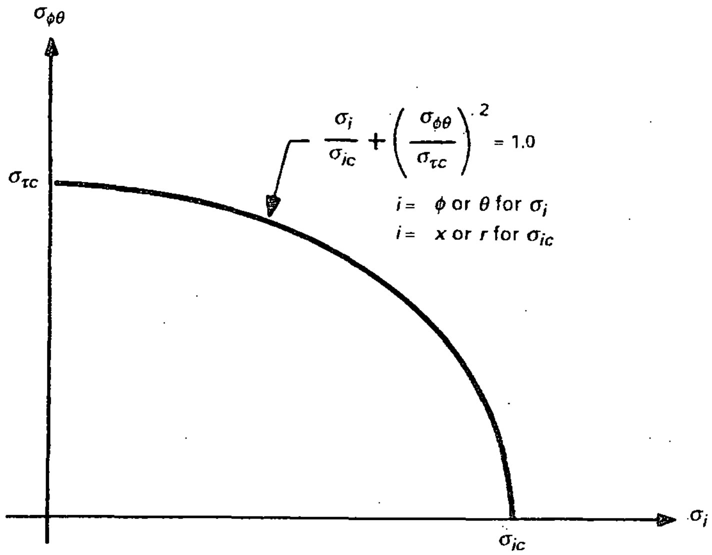



FIG. -1713.1.3-1 RADII $R_1$ AND $R_2$ FOR TOROIDAL AND ELLIPSOIDAL HEAD




**(a) Axial Compression Plus Hoop Compression**




**(b) Axial Compression or Hoop Compression Plus In-Plane Shear**

FIG. -1713.2-1 INTERACTION CURVES FOR INELASTIC BUCKLING OF CYLINDERS UNDER COMBINED LOADS for $\sigma_{iej}$ and $\alpha_{ij}$ and changing the right side of the equalities from 1.0 and 1.2 or by the following equations. These equations are based upon the recommendation that the stringer buckling and general instability stresses be 20% greater than the average of the local shell buckling stresses in the adjacent panels. The method for sizing stiffeners will always be conservative because the stiffener size determined from the following equations will be adequate for each of the uniaxial buckling stress components. For ring stiffened cylinders and stiffened spherical heads simple equations are given for sizing stiffeners. The equations for a stringer stiffened cylinder are more complex and require a computer for solving. The method for sizing stiffeners is based upon the following relationship:

$$\sigma_{iej} = \frac{1.2\sigma_{ieL}\alpha_{iL}}{\alpha_{iG}}$$

The above requirement is conservative under combined stress states and for inelastic buckling as well as elastic buckling. In the case of combined stress states provide a stiffener with the largest value of the moment of inertia calculated for each uniaxial stress state.

**-1714.1 Cylindrical Shells — Ring Stiffened**

*(a) Axial Compression*

$$A_\theta \geq \left(\frac{0.334}{M_s^{0.6}} - 0.063\right) \ell_{s\phi} t \text{ and } A_\theta \geq 0.06\ \ell_{s\phi} t$$

The following equation is based upon the recommendation that the effective stiffener section provides a bending stiffness equal to that of an unstiffened shell having the same buckling stress.

$$I_{E\theta} \geq \frac{5.33\ \ell_{s\phi} t^3}{M_s^{1.8}}$$

*(b) Hoop Compression*

*(1)* Intermediate Size Ring

$$I_{E\theta} \geq \frac{1.2\sigma_{\theta eL}\ \ell_{s\phi} R_c^2 t}{E(n^2 - 1)}$$

$\sigma_{\theta eL}$ = stress determined from -1712.1.1(b) for $M_\phi = M_s$

$$n^2 = \frac{1.875R^{3/2}}{L_B t^{1/2}}$$

*(2)* End Stiffeners — Rings Which Act as Bulkheads

$$I_{FE} = \frac{1.5\sigma_{\theta F} L_s R_c^2 t}{E(n^2 - 1)}$$

where

$I_{FE}$ = the value of $I_{E\theta}$ which makes a large stiffener fully effective, that is, equivalent to a bulkhead. The effective width of shell $\ell_{e\phi} = 1.56\sqrt{Rt}\ A_1/A_2$

$A_1$ = area of large ring plus $\ell_\phi t$, in.$^2$

$A_2$ = area of intermediate size rings plus $\ell_\phi t$, in.$^2$

$\sigma_{\theta F}$ = average value of stress over distance $L_s$ where stress is determined from -1712.2.1(b) for a cylinder with $L = L_B$

$n$ = number of buckling waves determined for $\sigma_{\theta B}$ where $\sigma_{\theta B}$ is the stress determined from -1712.2.1(b) for a cylinder where the large stiffeners are assumed to be the same size as the small stiffeners and $\bar{\lambda} = \pi R/L$

*(c) Shear*

$I_{E\theta} = 0.184\ C_{\phi\theta} M_s^{0.8} t^3 \ell_{s\phi}$

$C_{\phi\theta}$ = value determined from -1712.1(c) for $M_\phi = M_s$

**-1714.2 Cylindrical Shells — Stringer Stiffened or Ring and Stringer Stiffened**

*(c) Axial Compression*

$$\sigma_{\phi eS} \geq \frac{1.2\sigma_{\phi eL}\alpha_{\phi L}}{\alpha_{\phi S}} \text{ and } \sigma_{\phi eG} \geq \frac{1.2\sigma_{\phi eL}\alpha_{\phi L}}{\alpha_{\phi G}}$$

See -1511(a) for $\alpha_{\phi L}$, -1521(a) for $\alpha_{\phi G}$, -1712.1.2(a) for $\sigma_{\phi eL}$ and -1712.2.2(a) for $\sigma_{\phi eS}$ and $\sigma_{\phi eG}$.

*(b) Hoop Compression*

$$\sigma_{\theta eS} \geq 1.2\sigma_{\theta eL}$$

and

$$\sigma_{\theta eG} \geq 1.2\sigma_{\theta eL}$$

See -1712.1.2(b) for $\sigma_{\theta eL}$ and -1712.2.2(b) for $\sigma_{\theta eS}$ and $\sigma_{\theta eG}$. Assume $K = 0$.

*(c) Shear*

$$\sigma_{\phi\theta eG} \geq 1.2\sigma_{\phi\theta eL}$$

See -1712.1.2(c) and -1712.2.2(c) for $\sigma_{\phi\theta eL}$ and $\sigma_{\phi\theta eG}$, respectively.

**-1714.3 Spherical Shells**

*(a)* One-Way Stiffeners

$$I_{E\phi} = \frac{62.4\ \ell_{s\phi} t^3}{M_s^{1.8}}\left(\frac{t}{\ell_{s\phi}}\right)^{2/4}$$

The above equation is for meridional stiffeners. Interchange $\theta$ with $\phi$ for circumferential stiffeners.

(b) Two-Way (Orthogonal) Stiffeners

$$\sigma_{ieG} \geq \frac{5.92Et}{M_s^{0.6}R}$$

The value for $\sigma_{ieG}$ is determined from -1712.2.3 and $M_s$ is the smaller of the values corresponding to the $\theta$ and $\phi$ directions.

**-1714.4 Toroidal or Ellipsoidal Shells.** Toroidal and ellipsoidal shells shall be analyzed as equivalent spheres by substituting $R_2$ for $R$ in the equations of -1714.3. See Fig. -1713.1.3-1 for $R_2$.

## -1720 Axisymmetric Shell of Revolution Bifurcation Analysis

An axisymmetric shell of revolution linear bifurcation analysis may be used for the buckling evaluation of the containment vessel. Two sets of stress components, $\sigma_{is}$ and $\sigma_{ip}$ are calculated by the procedure given in -1700. The stress components $\sigma_{is}$ are elastic whereas the stress components $\sigma_{ip}$ are used for buckling evaluation when one or more of the stress components is in the inelastic range. Independent buckling evaluations are to be made for components $\sigma_{is}$ and $\sigma_{ip}$. If all stress components are elastic, $\sigma_{is} = \sigma_{ip}$ and no evaluation need be made of stress components $\sigma_{ip}$.

The buckling stresses of cylinders under combined loads compare closely with the distortion energy theory when the uniaxial buckling stresses in the meridional and circumferential directions are equal to the yield stress of the material. This state of stress is considered in the stress intensity criteria of NE-3210. When the uniaxial buckling stresses in either the meridional or circumferential directions are in the inelastic range, no interaction effect between these two stress components need be considered. Therefore stress components $\sigma_{\phi p}$ can be set to zero when investigating combinations of $\sigma_{\theta p}$ and $\sigma_{\phi\theta p}$. Similarly, $\sigma_{\theta p}$ may be set to zero when investigating combinations of $\sigma_{\phi p}$ and $\sigma_{\phi\theta p}$.

The stress components $\sigma_{ip}$ are applied as quasistatic prebuckling stress states. The computer code will analyze the selected shell model for linear bifurcation buckling and determine the lowest multiple, $\lambda_c$, of the prebuckling stress state which causes buckling. A minimum value of $\lambda_c = 1.0$ is recommended for the local buckling mode of failure and a value of $\lambda_c = 1.2$ is recommended for the stringer buckling and general instability modes of failure. The design is adequate when the computed values of $\lambda_c$ are equal to or greater than the minimum recommended values.

## -1730 Three-Dimensional Thin-Shell Bifurcation Analysis

This paragraph gives the provisions for buckling evaluations of containment shells by use of three-dimensional computer programs for thin shells. The three-dimensional computer codes are more elaborate than those used for axisymmetric shell of revolution linear bifurcation analysis and are mostly based on finite element principles. The advantages of three-dimensional codes are that circumferential variation of geometry, material properties and loadings which exist due to presence of cutouts, penetrations, stiffeners and other attachments can be considered in the analysis. The choice of computer code should be based upon the type of problem to be solved and the degree of accuracy desired.

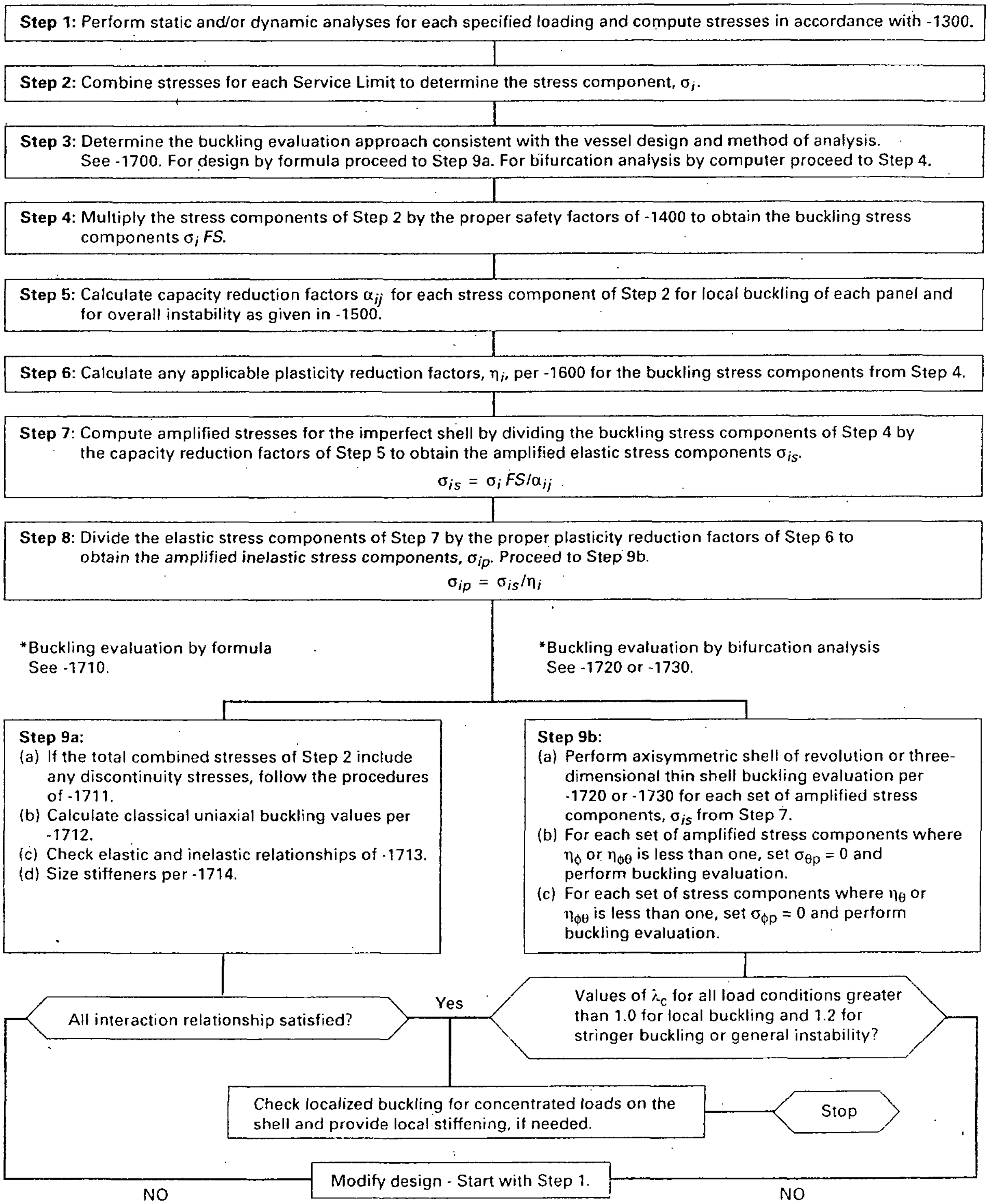
Two sets of stress components, $\sigma_{is}$ and $\sigma_{ip}$ are calculated by the procedure given in -1700. Independent buckling evaluations are to be made for these sets of stress components where $\sigma_{ip} \neq \sigma_{is}$. When considering the stress components $\sigma_{ip}$ it is conservative to assume that there is no interaction between meridional compression and hoop compression (see -1720). Therefore stress components $\sigma_{\phi p}$ can be set to zero when investigating combinations of $\sigma_{\theta p}$ and $\sigma_{\phi\theta p}$. Similarly, $\sigma_{\theta p}$ can be set to zero when investigating combinations of $\sigma_{\phi p}$ and $\sigma_{\phi\theta p}$.

The stress components $\sigma_{is}$ and $\sigma_{ip}$ are applied as quasi-static prebuckling stress states. The computer code will analyze the selected shell model for linear bifurcation buckling and determine the lowest multiple, $\lambda_c$, of the prebuckling stress state which causes buckling. A minimum value of $\lambda_c = 1.0$ is recommended for the local buckling mode of failure and a value of $\lambda_c = 1.2$ is recommended for the stringer buckling and general instability modes of failure. The design is adequate when the computed values of $\lambda_c$ are equal to or greater than the minimum recommended values.

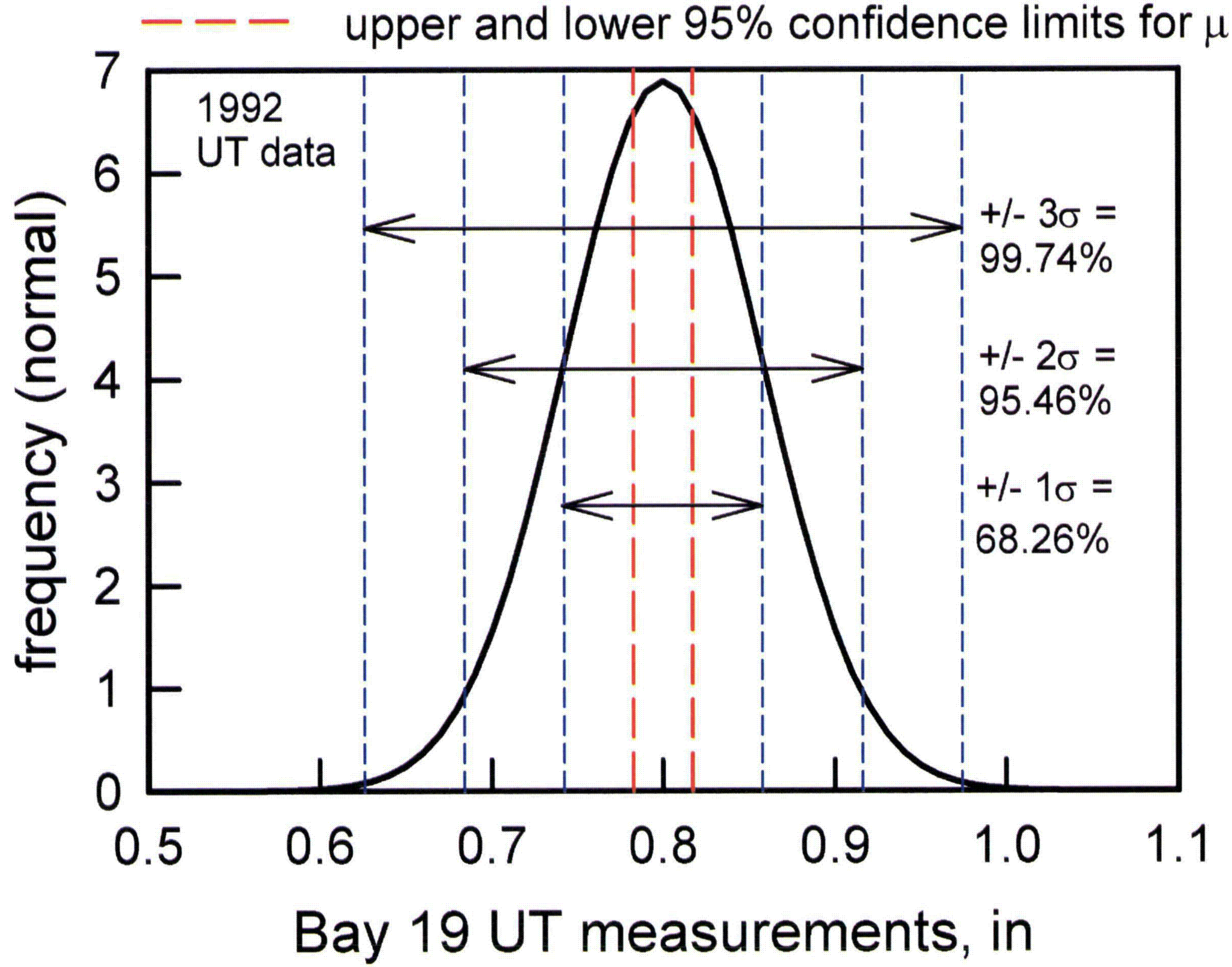
## -1800 SUMMARY

Table 1800-1 summarizes the rules of this Case to aid the designer in using these rules. The containment shell must also satisfy all other applicable Code criteria.

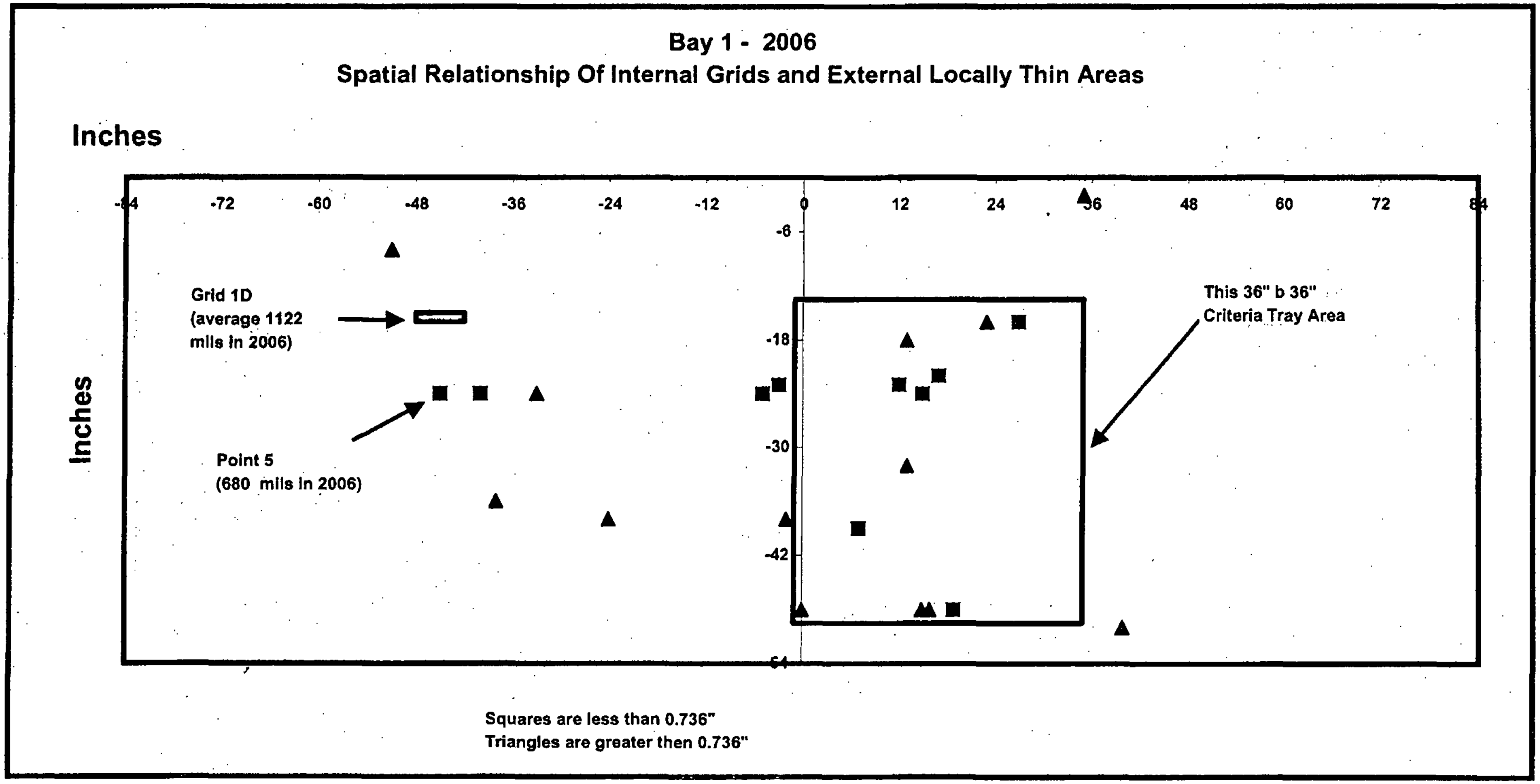
TABLE -1800-1
FLOWCHART

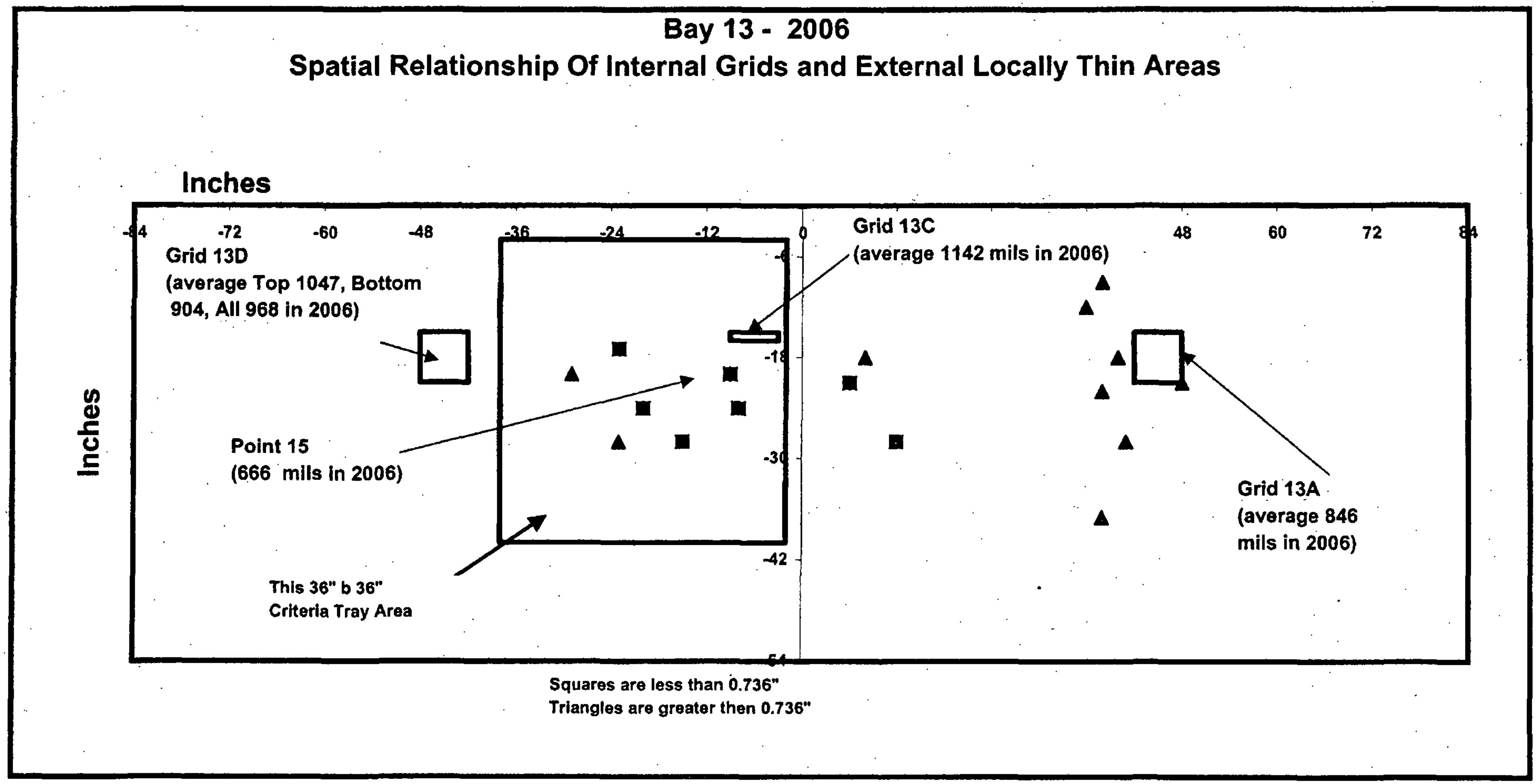


APPLICANT'S EXHIBIT 43

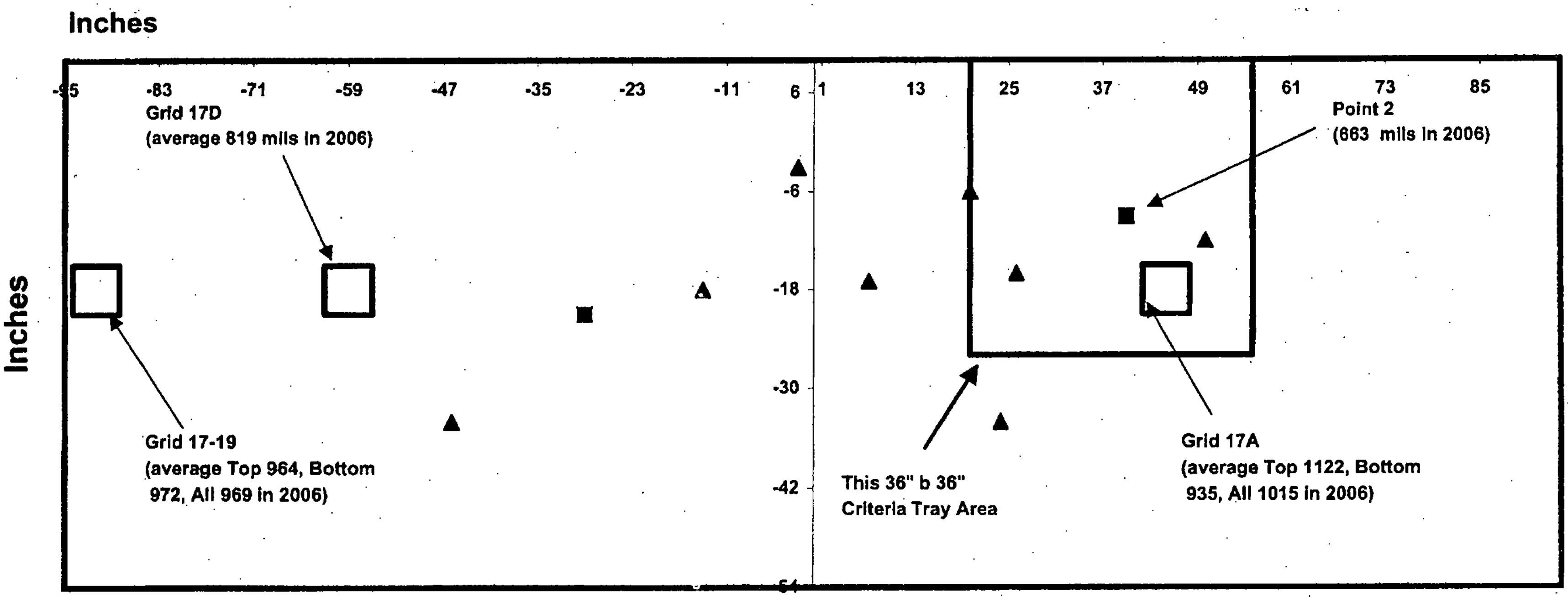


APPLICANT'S EXHIBIT 44




Bay 13 - 2006
Spatial Relationship Of Internal Grids and External Locally Thin Areas
Inches
Inches
-84
-72
-60
-48
-36
-24
-12
0
48
60
72
84
-6
-18
-30
-42
-54
Grid 13D
(average Top 1047, Bottom
904, All 968 in 2006)
Grid 13C
(average 1142 mils in 2006)
Point 15
(666 mils in 2006)
Grid 13A
(average 846
mils in 2006)
This 36" b 36"
Criteria Tray Area
Squares are less than 0.736"
Triangles are greater then 0.736"

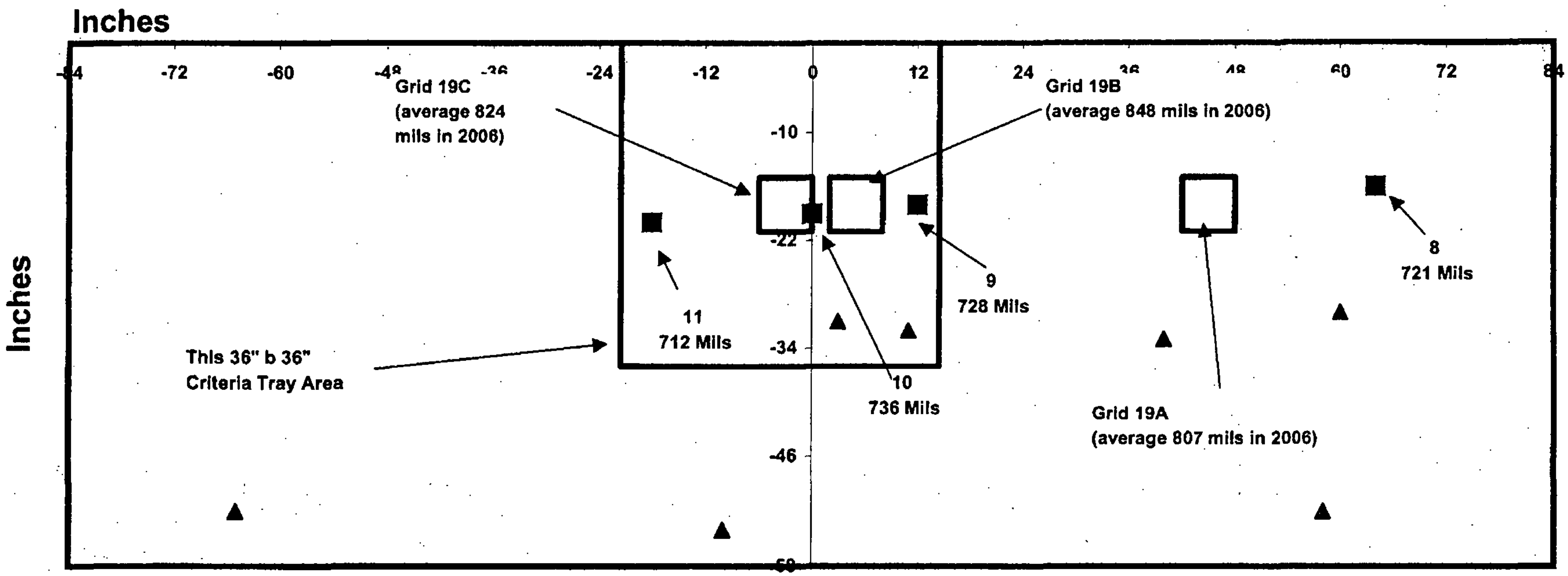
## Bay 17 - 2006
## Spatial Relationship Of Internal Grids and External Locally Thin Areas




Squares are less than 0.736"
Triangles are greater then 0.736"

**Bay 19 - 2006**

**Spatial Relationship Of Internal Grids and External Locally Thin Areas**




Squares are less than 0.736"
Triangles are greater then 0.736"

Approval Date: August 14, 1997

*See Numeric Index for expiration and any reaffirmation dates.*

**Case N-513**
**Evaluation Criteria for Temporary Acceptance of Flaws in Class 3 Piping**
**Section XI, Division 1**

*Inquiry:* What rules may be used for temporary acceptance of flaws, including through-wall flaws, in moderate energy Class 3 piping, without repair or replacement?

*Reply:* It is the opinion of the Committee that the following rules may be used to accept flaws, including through-wall flaws, in moderate energy Class 3 piping, without repair or replacement for a limited time, not exceeding the time to the next scheduled outage.

## 1.0 SCOPE

*(a)* These requirements apply to the ASME Section III, ANSI B31.1, and ANSI B31.7 piping, classified by the Owner as Class 3.

*(b)* The provisions of the Case apply to Class 3 piping whose maximum operating temperature does not exceed 200°F and whose maximum operating pressure does not exceed 275 psig.

*(c)* The following flaw evaluation criteria are permitted for pipe and tube. The flaw evaluation criteria are permitted for adjoining fittings and flanges to a distance of $(R_o t)^{1/2}$ from the weld centerline.

*(d)* The provisions of this Case demonstrate the integrity of the item and not the consequences of leakage. It is the responsibility of the Owner to demonstrate system operability considering effects of leakage.

## 2.0 PROCEDURE

*(a)* The flaw geometry shall be characterized by volumetric inspection methods or by physical measurement. The full pipe circumference at the flaw location shall be inspected to characterize the length and depth of all flaws in the pipe section.

*(b)* Flaw shall be classified as planar or nonplanar.

*(c)* When multiple flaws, including irregular (compound) shape flaws, are detected, the interaction and combined area loss of flaws in a given pipe section shall be accounted for in the flaw evaluation.

*(d)* A flaw evaluation shall be performed to determine the conditions for flaw acceptance. Section 3.0 provides accepted methods for conducting the required analysis.

*(e)* Frequent periodic inspections of no more than 30 day intervals shall be used to determine if flaws are growing and to establish the time at which the detected flaw will reach the allowable size. Alternatively, a flaw growth evaluation may be performed to predict the time at which the detected flaw will grow to the allowable size. When a flaw growth analysis is used to establish the allowable time for temporary operation, periodic examinations of no more than 90 day intervals shall be conducted to verify the flaw growth analysis predictions.

*(f)* For through-wall leaking flaws, leakage shall be observed by daily walkdowns to confirm the analysis conditions used in the evaluation remain valid.

*(g)* If examinations reveal flaw growth rate to be unacceptable, a repair or replacement shall be performed.

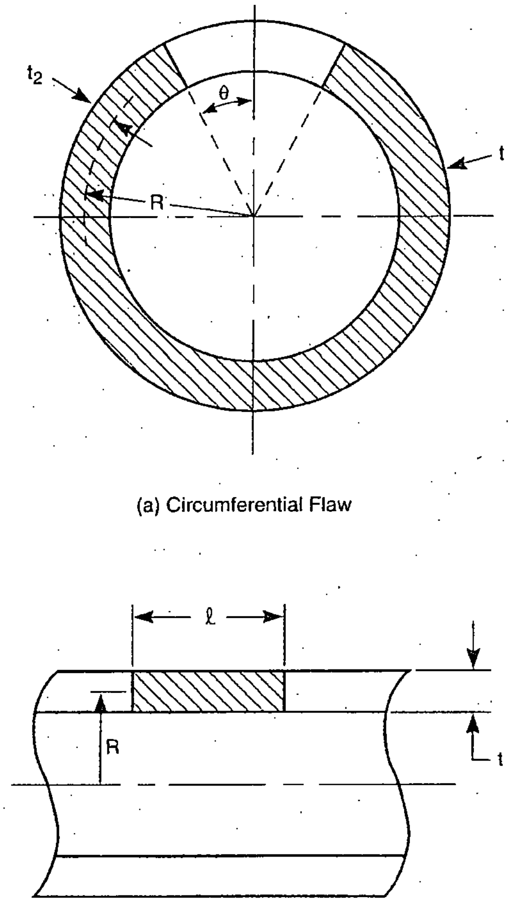
*(h)* Repair or replacement shall be performed no later than when the predicted flaw size from either periodic inspection or by flaw growth analysis exceeds the acceptance criteria of Section 4.0, or the next scheduled outage, whichever occurs first. Repair or replacement shall be in accordance with IWA-4000 or IWA-7000, respectively, in Editions and Addenda prior to the 1991 Addenda; and, in the 1991 Addenda and later, in accordance with IWA-4000.

*(i)* Evaluations and examination shall be documented in accordance with IWA-6300. The Owner shall document the use of this Case on the applicable data report form.

## 3.0 FLAW EVALUATION

*(a)* For planar flaws, the flaw shall be bounded by a rectangular or circumferential planar area in accordance with the methods described in Appendix C or Appendix H. IWA-3300 shall be used to determine when multiple proximate flaws are to be evaluated as a single flaw. The geometry of a through-wall planar flaw is shown in Fig. 1.

*(b)* For planar flaws in austenitic piping, the evaluation procedure in Appendix C of Section XI, Division 1, shall be used. Flaw depths up to 100% of wall




(a) Circumferential Flaw

(b) Axial Flaw

FIG. 1 THROUGH-WALL FLAW GEOMETRY

thickness may be evaluated. When through-wall circumferential flaws are evaluated, the formulas for evaluation given in Articles C-3320 of Appendix C may be used, with the flaw penetration $(a/t)$ equal to unity.

When through-wall axial flaws are evaluated, the allowable flaw length is:

$$\ell_{all} = 1.58\sqrt{Rt}\left[\left(\frac{\sigma_f}{(SF)\sigma_h}\right)^2 - 1\right]^{1/2} \tag{1}$$

$$\sigma_h = pD_o/2t \tag{2}$$

$$\sigma_f = (S_y + S_u)/2 \tag{3}$$

where

$p$ = is pressure for the loading condition
$D_o$ = is pipe outside diameter
$\sigma_f$ = is the flow stress
$S_y$ = is the code yield strength
$S_u$ = is the code tensile strength and
$SF$ = is the safety factor as specified in C-3420 of Appendix C

Material properties at the temperature of interest shall be used.

*(c)* For planar flaws in ferritic piping, the evaluation procedure in Article H-7000 of Appendix H, Section XI, Division 1, shall be used. Flaw depths up to 100% of wall thickness may be evaluated. When through-wall flaws are evaluated, the formulas for evaluation given in Articles H-7300 and H-7400 of Appendix H may be used, but with values for $F_m$, $F_b$, and $F$ applicable to through-wall flaws. Relations for $F_m$, $F_b$, and $F$ that take into account flaw shape and pipe geometry ($R/t$ ratio) shall be used. The appendix to this Code Case provides equations for $F_m$, $F_b$, and $F$ for a selected range of $R/t$. Geometry of a through-wall crack is shown in Fig. 1.

*(d)* For nonplanar flaws, the pipe is acceptable when the remaining pipe thickness $(t_p)$ is greater than or equal to the minimum wall thickness $t_{min}$):

$$t_{min} = \frac{pD_o}{2(S + 0.4p)} \tag{4}$$

where

$p$ = is the maximum operating pressure at flaw location
$S$ = is the allowable stress at operating temperature

Where appropriate, bending load at the flaw location shall be considered in the determination of $t_{min}$. When $t_p$ is less than $t_{min}$, an evaluation shall be performed as given below. The evaluation procedure is a function of the depth and the extent of the affected area as illustrated in Fig. 2.

*(1)* When the width of wall thinning that exceeds $t_{min}$, $W_m$, is less than or equal to 0.5 $(R_o t_{min})^{1/2}$, where $R_o$ is the outside radius and $W_m$ is defined in Fig. 2, the flaw can be classified as a planar flaw and evaluated under para. 3(a) through para. 3(c). When the above requirement is not satisfied, (2) shall be met.

*(2)* When the transverse extent of wall thinning that exceeds $t_{min}$, $L_{m(t)}$, is not greater than $(R_o t_{min})^{1/2}$,

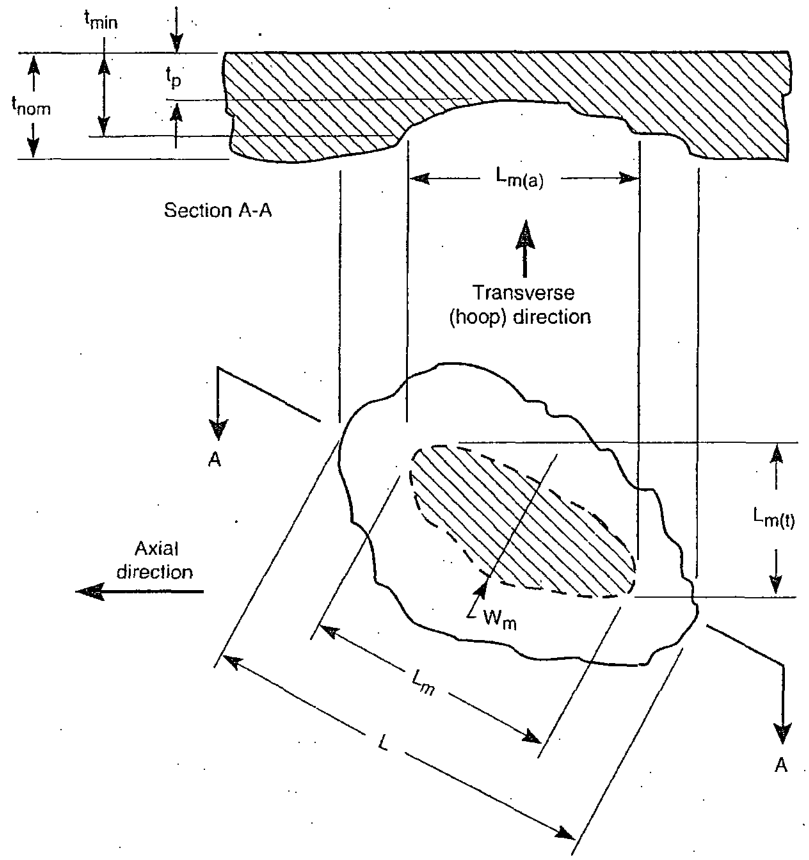



FIG. 2 ILLUSTRATION OF NONPLANAR FLAW DUE TO WALL THINNING

$t_{aloc}$ is determined from Curve 1 of Fig. 3, where $L_{m(t)}$ is defined in Fig. 2. When the above requirement is not satisfied, (3) shall be met.

*(3)* When the maximum extent of wall thinning that exceeds $t_{min}$, $L_m$, is less than or equal to 2.65 $(R_o t_{min})^{1/2}$ and $t_{nom}$ is greater than $1.13 t_{min}$, $t_{aloc}$ is determined by satisfying both of the following equations:

$$\frac{t_{aloc}}{t_{min}} \geq \frac{1.5\sqrt{R_o t_{min}}}{L}\left[1 - \frac{t_{nom}}{t_{min}}\right] + 1.0 \qquad (5)$$

$$\frac{t_{aloc}}{t_{min}} \geq \frac{0.353 L_m}{\sqrt{R_o t_{min}}} \qquad (6)$$

When the above requirements are not satisfied, (4) shall be met.

*(4)* When the requirements of (1), (2) and (3) above are not satisfied, $t_{aloc}$ is determined from Curve 2 of Fig. 3. In addition, $t_{aloc}$ shall satisfy the following equation:

$$\frac{t_{aloc}}{t_{min}} \geq \frac{\left[0.5 + \left(\frac{t_{nom}}{t_{min}}\right)\left(\frac{\sigma_b}{S}\right)\right]}{1.8} \qquad (7)$$

where $\sigma_b$ is the nominal pipe longitudinal bending stress resulting from all primary pipe loadings.

*(e)* For nonferrous materials, nonplanar and planar flaws may be evaluated following the general approach

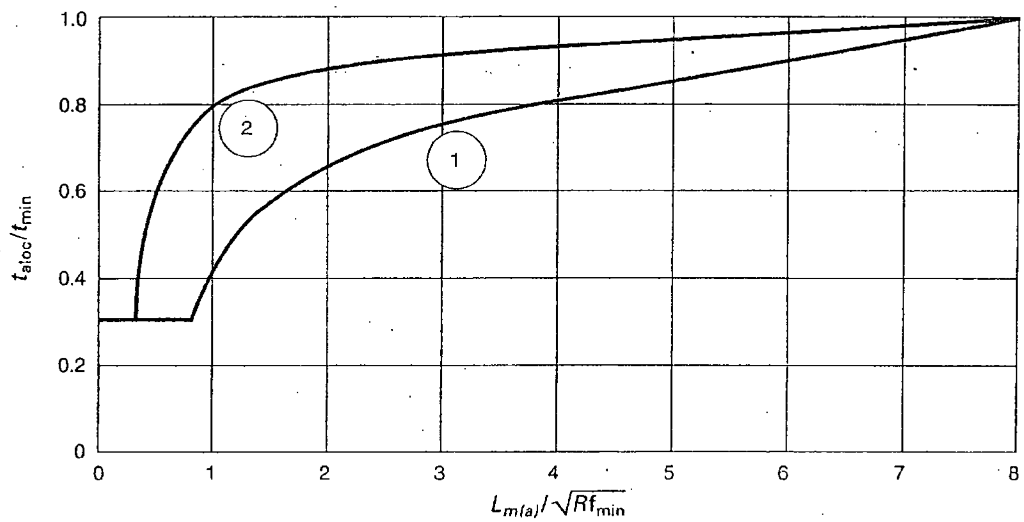



FIG. 3 ALLOWABLE WALL THICKNESS AND LENGTH OF LOCALLY THINNED AREA

of (a) through (d) above. For ductile materials, the approach given in (b) may be used; otherwise, the approach given in (c) and (d) should be applied. Safety factors provided in Section 4.0 shall be used. It is the responsibility of the evaluator to establish conservative estimates of strength and fracture toughness for the piping material.

## 4.0 ACCEPTANCE CRITERIA

The piping containing a circumferential planar flaw is acceptable for continued temporary service when flaw evaluation provides a safety margin, based on load, of a factor of 2.77 for Level A and B and 1.39 for Level C and D service loading conditions. Piping containing a nonplanar flaw is acceptable for continued temporary service if $t_p \geq t_{aloc}$, where $t_{aloc}$ is determined from Section 3(d).

Lower safety factors may be used, provided that a detailed engineering evaluation of continued operation demonstrates that lower safety factors are justified.

## 5.0 AUGMENTED EXAMINATION

An augmented volumetric examination or physical measurement to assess degradation of the affected system shall be performed as follows:

*(a)* From the engineering evaluation, the most susceptible locations shall be identified. A sample size of at least five of the most susceptible and accessible locations, or, if fewer than five, all susceptible and accessible locations shall be examined within 30 days of detecting the flaw.

*(b)* When a flaw is detected, an additional sample of the same size as defined in 5(a) shall be examined.

*(c)* This process shall be repeated within 15 days for each successive sample, until no significant flaw is detected or until 100% of susceptible and accessible locations have been examined.

## 6.0 NOMENCLATURE

$c$ = half crack length
$D_o$ = outside pipe diameter
$F$ = nondimensional stress intensity factor for through-wall axial flaw under hoop stress
$F_b$ = nondimensional stress intensity factor for through-wall circumferential flaw under pipe bending stress
$F_m$ = nondimensional stress intensity factor for through-wall circumferential flaw under membrane stress
$\ell$ = total crack length $= 2c$
$\ell_{all}$ = allowable axial through-wall length

$L$ = maximum extent of a local thinned area with $t < t_{nom}$
$L_m$ = maximum extent of a local thinned area with $t < t_{min}$
$L_{m(a)}$ = axial extent of wall thinning below $t_{min}$
$L_{m(t)}$ = circumferential extent of wall thinning below $t_{min}$
$p$ = maximum operating pressure at flaw location
$R$ = mean pipe radius
$R_o$ = outside pipe radius
$S$ = allowable stress at operating temperature
$S_u$ = code specified ultimate tensile strength
$S_y$ = code specified yield strength
$t$ = wall thickness
$t_{aloc}$ = allowable local thickness for a nonplanar flaw that exceeds $t_{min}$
$t_{min}$ = minimum wall thickness required for pressure loading
$t_{nom}$ = nominal wall thickness
$t_p$ = minimum remaining wall thickness
$W_m$ = maximum extent of a local thinned area perpendicular to $L_m$ with $t < t_{min}$
$\lambda$ = nondimensional half crack length for through-wall axial flaw
$\sigma_f$ = material flow stress
$\sigma_h$ = pipe hoop stress due to pressure
$\sigma_b$ = nominal longitudinal bending stress for primary loading without stress intensification factor
$\Theta$ = half crack angle for through-wall circumferential flaw

# APPENDIX I
# RELATIONS FOR $F_m$, $F_b$, AND $F$ FOR THROUGH-WALL FLAWS

## I-1.0 DEFINITIONS

For through-wall flaws, the crack depth (a) will be replaced with half crack length (c) in the stress intensity factor equations in Articles H-7300 and H-7400 of Section XI, Appendix H. Also, Q will be set equal to unity in Article H-7400.

## I-2.0 CIRCUMFERENTIAL FLAWS

For a range of $R/t$ between 5 and 20, the following equations for $F_m$ and $F_b$ may be used:

$$F_m = 1 + A_m (\Theta/\pi)^{1.5} + B_m (\Theta/\pi)^{2.5} + C_m (\Theta/\pi)^{3.5}$$

$$F_b = 1 + A_b (\Theta/\pi)^{1.5} + B_b (\Theta/\pi)^{2.5} + C_b (\Theta/\pi)^{3.5}$$

where

$\Theta$ = Half crack angle = $c/R$
$R$ = Mean pipe radius
$t$ = Pipe wall thickness

and

$$A_m = -2.02917 + 1.67763\,(R/t) - 0.07987\,(R/t)^2 + 0.00176\,(R/t)^3$$

$$B_m = 7.09987 - 4.42394\,(R/t) + 0.21036\,(R/t)^2 - 0.00463\,(R/t)^3$$

$$C_m = 7.79661 + 5.16676\,(R/t) - 0.24577\,(R/t)^2 + 0.00541\,(R/t)^3$$

$$A_b = -3.26543 + 1.52784\,(R = /t) - 0.072698\,(R/t)^2 + 0.0016011\,(R/t)^3$$

$$B_b = 11.36322 - 3.91412\,(R/t) + 0.18619\,(R/t)^2 - 0.004099\,(R/t)^3$$

$$C_b = -3.18609 + 3.84763\,(R/t) - 0.18304\,(R/t)^2 + 0.00403\,(R/t)^3$$

Equations for $F_m$ and $F_b$ are accurate for $R/t$ between 5 and 20 and become increasingly conservative for $R/t$ greater than 20. Alternative solutions for $F_m$ and $F_b$ may be used when $R/t$ is greater than 20.

## I-3.0 AXIAL FLAWS

For internal pressure loading, the following equation for $F$ may be used:

$$F = 1 + 0.072449\lambda + 0.64856\lambda^2 - 0.2327\lambda^3 + 0.038154\lambda^4 - 0.0023487\lambda^5$$

where

$\lambda = c/(Rt)^{1/2}$
$c$ = half crack length

The equation for $F$ is accurate for $\lambda$ between 0 and 5. Alternative solutions for $F$ may be used when $\lambda$ is greater than 5.

APPLICANT'S EXHIBIT 46

SSINS No.: 6820
OMB No.: 3150-0011
NRCB 87-01

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

July 9, 1987

# NRC BULLETIN NO. 87-01: THINNING OF PIPE WALLS IN NUCLEAR POWER PLANTS

## Addressees:

All licensees for nuclear power plants holding an operating license or a construction permit.

## Purpose:

The purpose of this bulletin is to request that licensees submit information concerning their programs for monitoring the thickness of pipe walls in high-energy single-phase and two-phase carbon steel piping systems.

## Description of Circumstances:

On December 9, 1986, Unit 2 at the Surry Power Station experienced a catastrophic failure of a main feedwater pipe, which resulted in fatal injuries to four workers. This event was reported in IE Information Notice (IN) 86-106, "Feedwater Line Break," on December 16, 1986; IN 86-106, Supplement 1, on February 13, 1987; and IN 86-106, Supplement 2, on March 18, 1987. The licensee submitted Licensee Event Report (LER) 86-020-00 on January 8, 1987; Revision 1, LER 86-020-01, on January 14, 1987; and Revision 2, LER 86-020-02, on March 31, 1987. A comprehensive report entitled "Surry Unit 2 Reactor Trip and Feedwater Pipe Failure Report," was attached to the updated LER, Revisions 1 and 2. The findings of NRC's Augmented Inspection Team were issued on February 10, 1987, in IE Inspection Report Nos. 50-280/86-42 and 50-281/86-42.

Investigation of the accident and examination of data by the licensee, NRC, and others led to the conclusion that failure of the piping was caused by erosion/corrosion of the carbon steel pipe wall. Although erosion/corrosion pipe failures have occurred in other carbon steel systems, particularly in small diameter piping in two-phase systems and in water systems containing suspended solids, there have been few previously reported failures in large diameter systems containing high-purity water. Consistent with general industry practice, the licensee did not have in place an inspection program for examining the thickness of the walls of feedwater and condensate piping.

Main feedwater systems, as well as other power conversion systems, are important to safe operation. Failures of active components in these systems, for example, valves or pumps, or of passive components such as piping, can result in undesirable challenges to plant safety systems required for safe shutdown and accident mitigation. Failure of high-energy piping, such as feedwater

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Concurrence Copy

system piping, can result in complex challenges to operating staff and the plant because of potential systems interactions of high-energy steam and water with other systems, such as electrical distribution, fire protection, and security systems. All licensees have either explicitly or implicitly committed to maintain the functional capability of high-energy piping systems that are a part of the licensing basis for the facility. An important part of this commitment is that piping will be maintained within allowable thickness values.

Actions Requested:

Within 60 days from the receipt of this bulletin, licensees are requested to provide the following information concerning their programs for monitoring the wall thickness of pipes in condensate, feedwater, steam, and connected high-energy piping systems, including all safety-related and non-safety-related piping systems fabricated of carbon steel:

1. Identify the codes or standards to which the piping was designed and fabricated.

2. Describe the scope and extent of your programs for ensuring that pipe wall thicknesses are not reduced below the minimum allowable thickness. Include in the description the criteria that you have established for:

   a. selecting points at which to make thickness measurements
   b. determining how frequently to make thickness measurements
   c. selecting the methods used to make thickness measurements
   d. making replacement/repair decisions

3. For liquid-phase systems, state specifically whether the following factors have been considered in establishing your criteria for selecting points at which to monitor piping thickness (Item 2a):

   a. piping material (e.g., chromium content)
   b. piping configuration (e.g., fittings less than 10 pipe diameters apart)
   c. pH of water in the system (e.g., pH less than 10)
   d. system temperature (e.g., between 190 and 500° F)
   e. fluid bulk velocity (e.g., greater than 10 ft/s)
   f. oxygen content in the system (e.g., oxygen content less than 50 ppb)

4. Chronologically list and summarize the results of all inspections that have been performed, which were specifically conducted for the purpose of identifying pipe wall thinning, whether or not pipe wall thinning was discovered, and any other inspections where pipe wall thinning was discovered even though that was not the purpose of that inspection.

   a. Briefly describe the inspection program and indicate whether it was specifically intended to measure wall thickness or whether wall thickness measurements were an incidental determination.

   b. Describe what piping was examined and how (e.g., describe the inspection instrument(s), test method, reference thickness, locations examined, means for locating measurement point(s) in subsequent inspections).

c. Report thickness measurement results and note those that were identified as unacceptable and why.

d. Describe actions already taken or planned for piping that has been found to have a nonconforming wall thickness. If you have performed a failure analysis, include the results of that analysis. Indicate whether the actions involve repair or replacement, including any change of materials.

5. Describe any plans either for revising the present or for developing new or additional programs for monitoring pipe wall thickness.

The written report shall be submitted to the appropriate Regional Administrator under oath or affirmation under provisions of Section 182a, Atomic Energy Act of 1954, as amended. In addition, the original of the cover letter and a copy of the report shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555 for reproduction and distribution.

This request for information was approved by the Office of Management and Budget under blanket clearance number 3150-0011. Comments on burden and duplication may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, D.C. 20503.

NRC intends to summarize the information collected under this bulletin and study it to help determine if additional actions are required by the staff and/or industry. The information will be analyzed and placed in the PDR.

If you have any questions about this matter, please contact the Regional Administrator of the appropriate NRC regional office or the technical contacts listed below.

Wayne D. Lanning for
Charles E. Rossi, Director
Division of Operational Events Assessment
Office of Nuclear Reactor Regulation

Technical Contacts: Paul Wu, NRR
(301) 492-8987

Conrad McCracken, NRR
(301) 492-7042

Attachment: List of Recently Issued Bulletins

Attachment
IRCB 87-01
July 9, 1987

LIST OF RECENTLY ISSUED
BULLETINS

| Bulletin No. | Subject | Date of Issuance | Issued to |
|---|---|---|---|
| 86-04 | Defective Teletherapy Timer that May Not Terminate Dose | 10/29/86 | All NRC licensees authorized to use cobalt-60 teletherapy units |
| 86-03 | Potential Failure of Multiple ECCS Pumps Due to Single Failure of Air-Operated Valve in Minimum Flow Recirculation Line | 10/8/86 | All facilities holding an OL or CP |
| 86-02 | Static "O" Ring Differential Pressure Switches | 7/18/86 | All power reactor facilities holding an OL or CP |
| 86-01 | Minimum Flow Logic Problems That Could Disable RHR Pumps | 5/23/86 | All GE BWR facilities holding an OL or CP |
| 85-03 | Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings | 11/15/85 | All power reactor facilities holding an OL or CP |
| 85-02 | Undervoltage Trip Attachments of Westinghouse DB-50 Type Reactor Trip Breakers | 11/5/85 | All power reactor facilities holding an OL or CP |
| 85-01 | Steam Binding of Auxiliary Feedwater Pumps | 10/29/85 | Nuclear power facilities and CPs listed in Attachment 1 for action; all other nuclear power facilities for information |

OL = Operating License
CP = Construction Permit

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

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c. Report thickness measurement results and note those that were identified as unacceptable and why.

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Charles E. Rossi, Director
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Attachment: List of Recently Issued Bulletins

*SEE PREVIOUS CONCURRENCES

| | | | | |
|---|---|---|---|---|
| | | | D/DOEA:NRR<br>CERossi<br>08/ /87 | *C/OGCB:DOEA:NRR<br>CHBerlinger<br>07/01/87 |
| *ECEB:DEST:NRR<br>PWu<br>06/29/87 | *AC/ECEB:DEST:NRR<br>CMcCracken<br>06/29/87 | *EAD/DEST:NRR<br>JRichardson<br>06/29/87 | *D/DEST:NRR<br>LShao<br>06/30/87 | *PPMB:ARM<br>TechEd<br>06/29/87 |

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5. Describe any plans either for revising the present or for developing new or additional programs for monitoring pipe wall thickness.

The written report shall be submitted to the appropriate Regional Administrator under oath or affirmation under provisions of Section 182a, Atomic Energy Act of 1954, as amended. In addition, the original of the cover letter and a copy of the report shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555 for reproduction and distribution.

This request for information was approved by the Office of Management and Budget under blanket clearance number 3150-0011. Comments on burden and duplication may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, D.C. 20503.

NRC intends to summarize the information collected under this bulletin and study it to help determine if additional actions are required by the staff and/or industry. The information will be analyzed and placed in the PDR.

If you have any questions about this matter, please contact the Regional Administrator of the appropriate NRC regional office or the technical contact listed below.

Charles E. Rossi, Director
Division of Operational Event Assessment
Office of Nuclear Reactor Regulation

Technical Contacts: Paul Wu, NRR
(301) 492-8987
Conrad McCracken, NRR
(301) 492-7042

Attachments:
1. IE IN 86-106
2. IE IN 86-106, Supplement 1
3. IE IN 86-106, Supplement 2
4. List of Recently Issued IE Bulletins

AK for CHB 7/1/87

*SEE PREVIOUS CONCURRENCES

| | | | | |
|---|---|---|---|---|
| | | | D/DOEA:NRR<br>CERossi<br>06/ /87 | C/OGCB:DOEA:NRR<br>CHBerlinger<br>07/1/87 |
| *ECEB:DEST:NRR<br>PWu<br>06/29/87 | *AC/ECEB:DEST:NRR<br>CMcCracken<br>06/29/87 | *EAD/DEST:NRR<br>JRichardson<br>06/29/87 | *D/DEST:NRR<br>LShao<br>06/30/87 | *PPMB:ARM<br>TechEd<br>06/29/87 |

c. Report thickness measurement results and note those which were identified as unacceptable and why.

d. Describe actions already taken or planned for piping which has been found to have a nonconforming wall thickness. If you have performed a failure analysis, include the results of that analysis. Indicate whether the actions involve repair or replacement, including any change of materials.

5. Describe any plans either for revising the present or for developing new or additional programs for monitoring pipe wall thickness.

The written report shall be submitted to the appropriate Regional Administrator under oath or affirmation under provisions of Section 182a, Atomic Energy Act of 1954, as amended. In addition, the original of the cover letter and a copy of the report shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555 for reproduction and distribution.

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| | | | | |
|---|---|---|---|---|
| | | | D/DOEA:NRR<br>CERossi<br>06/ /87 | C/OGCB:DOEA:NRR<br>CHBerlinger<br>06/ /87 |
| ECEB:DEST:NRR<br>PWu<br>06/29/87 | AC/ECEB:DEST:NRR<br>CMcCracken<br>06/29/87 | EAD/DEST:NRR<br>JRichardson<br>06/29/87 | D/DEST:NRR<br>LShao<br>06/30/87 | PPMB:ARM<br>TechEd<br>06/29/87 |

APPLICANT'S EXHIBIT 47

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

May 2, 1989

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: EROSION/CORROSION-INDUCED PIPE WALL THINNING (GENERIC LETTER 89 - 08)

Pursuant to 10 CFR 50.54(f), the U.S. Nuclear Regulatory Commission (NRC) is requiring information to assess safe operation of reactors when erosion/corrosion significantly degrades piping and components of high-energy carbon steel piping systems. The principal concern is whether the affected plants continue to meet their licensing basis when erosion/corrosion degrades the pressure boundary to below the applicable code design value.

Main feedwater systems, as well as other power conversion systems, are important to safe operation. Failures in these systems of active components such as valves or pumps or of passive components such as piping can result in undesirable challenges to plant safety systems required for safe shutdown and accident mitigation. Failure of high-energy piping, such as feedwater system piping, can result in complex challenges to operating staff and the plant because of potential system interactions of high-energy steam and water with other systems, such as electrical distribution, fire protection, and security. All licensees have committed to adhere to criteria, codes and standards for high-energy piping systems described in licensing documents. Such commitments are a part of the licensing basis for the facility. An important part of this commitment is that piping will be maintained within allowable thickness values.

Our concerns regarding this issue were prompted by incidents at Surry Unit 2 and the Trojan plant. The Surry incident occurred on December 6, 1986, and it was caused by catastrophic failure of feedwater piping. The Trojan incident was discovered in June 1987, which was the first time that pipe wall thinning led to piping replacement in the safety-related portion of the feedwater lines. In addition to these two cases, incidents of pipe wall thinning or rupture because of erosion or erosion/corrosion have been reported at many other nuclear power plants. In many of these cases, the licensees had inspected the two-phase lines for some years, but it was not until the Surry incident that they started to examine some single-phase lines. Many licensees discovered pipe wall thinning in the single-phase lines. Some of the reported incidents are listed below:

1. A pipe rupture at Haddam Neck occurred in March 1985. The pipe ruptured downstream of a normal level control valve for a feedwater heater. The actual rupture was approximately 1/2 inch by 2 1/4 inches, and the failure was caused by flow impingement. The eroded section of pipe was replaced. In addition, corresponding pipes of similar systems were examined.

2. A catastrophic pipe rupture at Surry Unit 2 occurred in December 1986. The break was located in an elbow in the 18-inch line about 1 foot from the 24-inch header. A 2- by 4-foot section of the wall of the suction

IDR-5
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LTR-

line to the A main feedwater pump was blown out. Investigation of the accident and examination of data by the licensee, NRC, and others led to the conclusion that failure of the piping was caused by erosion/corrosion of the carbon steel pipe wall.

3. During the June 1987 outage at the Trojan Nuclear Plant, it was discovered that at least two areas of the straight sections of the main feedwater piping system had experienced wall thinning to an extent that the pipe wall thickness would have reached the minimum thickness required by the design code (ANSI B31.7, "Nuclear Power Piping") during the next refueling cycle. These areas are in safety-related portions of the ASME Class 2 piping inside the containment. In addition, numerous piping components of the nonsafety-related portions of the feedwater lines were also found to have suffered extensive wall thinning.

4. During the September 1988 outage, the licensee for Surry Unit 2 discovered that pipe wall thinning had occurred more rapidly than expected. On the suction side of one of the main feedwater pumps, an elbow installed during the 1987 refueling outage lost 20 percent of its 0.500-inch wall in 1.2 years. In addition, wall thinning is continuing in safety-related main feedwater piping and in other nonsafety-related condensate piping. The exact cause of the accelerated wall thinning is still under investigation by both the licensee and the NRC.

In light of the above experiences, the NRC issued six information notices (86-106 and Supplements 1, 2, and 3; 87-36, and 88-17) and Bulletin 87-01 addressing this problem. The staff review of licensees' responses to the bulletin indicates that the pipe wall thinning problem is widespread for single-phase and two-phase high-energy carbon steel systems. The systems and components reported as having experienced pipe wall thinning are listed in Section 6 of the attachment to this letter. The staff review also showed that wall thinning in single phase feedwater-condensate systems is more prevalent among pressurized-water reactors (PWRs) but also occurs in boiling-water reactors (BWRs).

The staff audited 10 operating plants (7 PWRs and 3 BWRs) in late 1988 to assess implementation of erosion/corrosion monitoring programs by licensees and to ensure that adequate guidance was provided for corrective actions and other activities regarding repair and replacement of degraded piping and components. Detailed audit findings are described in Section 7 of NUREG-1344, which is enclosed with this letter. In general, all licensees have developed and put in place an erosion/corrosion monitoring program that meets the intent of NUMARC guidelines (Appendix A of NUREG-1344). In addition, all licensees have completed their initial examination as recommended by NUMARC. However, the staff found that none of these licensees has implemented formalized procedures or administrative controls to ensure continued long-term implementation of its erosion/corrosion monitoring program for piping and components within the licensing basis. Therefore, you should provide assurances that a program, consisting of systematic measures to ensure that erosion/corrosion does not lead to degradation of single phase and two phase high-energy carbon steel systems has been implemented. The detailed information should not be submitted for NRC review.

Additional insight into the phenomena related to erosion/corrosion of carbon steel components is provided in the enclosure to this letter (NUREG-1344).

You are required to submit your response, signed under oath or affirmation, as specified in 10 CFR 50.54(f), within 60 days of receipt of this letter. Your response will be used to determine whether your license should be modified, suspended, or revoked. Your response should include information on whether or not you have implemented or intend to implement a long term erosion/corrosion monitoring program that provides assurances that procedures or administrative controls are in place to assure that the NUMARC program or another equally effective program is implemented and the structural integrity of all high-energy (two phase as well as single phase) carbon steel systems is maintained. If this program is not yet implemented you should include the scheduled implementation date.

This request is covered by the Office of Management and Budget Clearance Number 3150-0011, which expires December 31, 1989. The estimated average burden is 200 man-hours per addressee response, including assessing the actions to be taken, preparing the necessary plans, and preparing the response. This estimated average burden pertains only to these identified response-related matters and does not include the time for actual implementation of the recommended actions.

Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Records and Reports Management Branch, Division of Information Support Services, Office of Information Resources Management, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555; and to the Paperwork Reduction Project (3150-0011), Office of Management and Budget, Washington, D.C. 20503.

Sincerely,

J. G. Partlow

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. NUREG-1344
2. Listing of Recently Issued
   Generic Letters

ENCLOSURE 2

LIST OF RECENTLY ISSUED GENERIC LETTERS

| Generic Letter No. | Subject | Date of Issuance | Issued To |
|---|---|---|---|
| 89-08 | ISSUANCE OF GENERIC LETTER 89-08: EROSION/CORROSION - INDUCED PIPE WALL THINNING - 10 CFR §50.54(f) | 5/2/89 | LICENSEES TO ALL POWER REACTORS, BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS |
| 89-07 | GENERIC LETTER 89-07, POWER REACTOR SAFEGUARDS CONTINGENCY PLANNING FOR SURFACE VEHICLE BOMBS | 4/28/89 | LICENSEES TO ALL BWRS, PWRS, AND VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS |
| 89-06 | TASK ACTION PLAN ITEM I.D.2 - SAFETY PARAMETER DISPLAY SYSTEM - 10 CFR §50.54(f) | 4/12/89 | LICENSEES OF ALL POWER REACTORS, BWRS, PWRS, HTGR, AND NSSS VENDORS IN ADDITION TO GENERAL CODES APPLICABLE TO GENERIC LETTERS |
| 89-05 | PILOT TESTING OF THE FUNDAMENTALS EXAMINATION | 4/4/89 | LICENSSES OF ALL POWER REACTORS AND APPLICANTS FOR A REACTOR OPERATOR'S LICENSE UNDER 10 CFR PART 55 |
| 89-04 | GUIDANCE ON DEVELOPING ACCEPTABLE INSERVICE TESTING PROGRAMS | 4/3/89 | ALL HOLDERS OF LIGHT WATER REACTOR OPERATING LICENSES AND CONSTRUCTION PERMITS |
| 89-03 | OPERATOR LICENSING NATIONAL EXAMINATION SCHEDULE | 3/24/89 | ALL POWER REACTOR LICENSEES AND APPLICANTS FOR AN OPERATING LICENSE |
| 89-02 | ACTIONS TO IMPROVE THE DETECTION OF COUNTERFEIT AND FRAUDULENTLY MARKETED PRODUCTS | 3/21/89 | ALL HOLDERS OF OPERATING LICENSES AND CONSTRUCTION PERMITS FOR NUCLEAR POWER REACTORS |

1992 Edition w/1992 Addenda

APPLICANT'S EXHIBIT 48

# ARTICLE IWE-1000
# SCOPE AND RESPONSIBILITY

## IWE-1100 SCOPE

This Subsection provides the rules and requirements for inservice inspection, repair, and replacement of Class MC pressure retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments in light-water cooled plants.

## IWE-1200 COMPONENTS SUBJECT TO EXAMINATION

### IWE-1210 EXAMINATION REQUIREMENTS

The examination requirements of this Subsection shall apply to Class MC pressure retaining components and their integral attachments and to metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments. These examinations shall apply to surface areas, including welds and base metal.

### IWE-1220 COMPONENTS EXEMPTED FROM EXAMINATION

The following components (or parts of components) are exempted from the examination requirements of IWE-2000:

*(a)* vessels, parts, and appurtenances that are outside the boundaries of the containment as defined in the Design Specifications;

*(b)* embedded or inaccessible portions of containment vessels, parts, and appurtenances that met the requirements of the original Construction Code;

*(c)* portions of containment vessels, parts, and appurtenances that become embedded or inaccessible as a result of vessel repair or replacement if the conditions of IWE-1232 and IWE-5220 are met;

*(d)* piping, pumps, and valves that are part of the containment system, or which penetrate or are attached to the containment vessel. These components shall be examined in accordance with the rules of IWB or IWC, as appropriate to the classification defined by the Design Specifications.

### IWE-1230 ACCESSIBILITY FOR EXAMINATION

#### IWE-1231 Accessible Surface Areas

*(a)* As a minimum, the following portions of Class MC containment vessels, parts, and appurtenances and Class CC metallic shell and penetration liners shall remain accessible for either direct or remote visual examination, from at least one side of the vessel, for the life of the plant:

*(1)* openings and penetrations;

*(2)* structural discontinuities;

*(3)* single-welded butt joints from the weld side;

*(4)* 80% of the surface area defined in Table IWE-2500-1, Examination Category E-A; and

*(5)* surface areas identified in IWE-1240.

*(b)* The requirements of IWE-1232 shall be met when accessibility for visual examination is not from the outside surface.

#### IWE-1232 Inaccessible Surface Areas

*(a)* Portions of Class MC containment vessels, parts, and appurtenances that are embedded in concrete or otherwise made inaccessible during construction of the vessel or as a result of vessel repair, modification, or replacement are exempted from examination, provided:

*(1)* no openings or penetrations are embedded in the concrete;

*(2)* all welded joints that are inaccessible for examination are double buttwelded and are fully radiographed and, prior to being covered, are tested for leak tightness using a gas medium test, such as Halide Leak Detector Test;

*(3)* all weld joints that are not double butt welded remain accessible for examination from the weld side; and

*(4)* the vessel is leak rate tested after completion of construction, repair, or replacement to the leak rate requirements of the Design Specifications.

*(b)* Portions of Class CC metallic shell and penetration liners that are embedded in concrete or otherwise made inaccessible during construction or as a result of repair or replacement are exempted from examination, provided:

*(1)* all welded joints that are inaccessible for examination are examined in accordance with CC-5520 and, prior to being covered or otherwise obstructed by adjacent structures, components, parts, or appurtenances, are tested for leak tightness in accordance with CC-5536; and

*(2)* the containment is leak rate tested after completion of construction, repair, or replacement to the leak rate requirements of the Design Specifications.

## IWE-1240 SURFACE AREAS REQUIRING AUGMENTED EXAMINATION

### IWE-1241 Examination Surface Areas

Surface areas likely to experience accelerated degradation and aging require the augmented examinations identified in Table IWE-2500-1, Examination Category E-C. Such areas include the following:

*(a)* interior and exterior containment surface areas that are subject to accelerated corrosion with no or minimal corrosion allowance or areas where the absence or repeated loss of protective coatings has resulted in substantial corrosion and pitting. Typical locations of such areas are those exposed to standing water, repeated wetting and drying, persistent leakage, and those with geometries that permit water accumulation, condensation, and microbiological attack. Such areas may include penetration sleeves, surfaces wetted during refueling, concrete-to-steel shell or liner interfaces, embedment zones, leak chase channels, drain areas, or sump liners.

*(b)* interior and exterior containment surface areas that are subject to excessive wear from abrasion or erosion that causes a loss of protective coatings, deformation, or material loss. Typical locations of such areas are those subject to substantial traffic, sliding pads or supports, pins or clevises, shear lugs, seismic restraints, surfaces exposed to water jets from testing operations or safety relief valve discharges, and areas that experience wear from frequent vibrations.

### IWE-1242 Identification of Examination Surface Areas

Surface areas requiring augmented examination shall be determined in accordance with IWE-1241, and shall be identified in the Owner's Inspection Program.

Examination methods shall be in accordance with IWE-2500(c).

# ARTICLE IWE-2000
# EXAMINATION AND INSPECTION

## IWE-2200 PRESERVICE EXAMINATION

*(a)* Examinations listed in Table IWE-2500-1 shall be completed prior to initial plant startup. These preservice examinations shall include the pressure retaining portions of components not exempted by IWE-1220.

*(b)* When visual examinations are required, these examinations shall be performed in accordance with IWE-2600, following the completion of the pressure test required by the Construction Code and after application of protective coatings (e.g., paint) when such coatings are required.

*(c)* When surface examinations are required by Table IWE-2500-1, shop or field examinations in accordance with NE-5000 for Class MC or CC-5500 for Class CC may serve in lieu of the on-site preservice examinations, provided:

*(1)* the examinations are conducted by the same method with equipment and techniques equivalent to those that are expected to be employed for subsequent inservice examinations;

*(2)* the shop or field examination records are, or can be, documented and identified in a form consistent with those required in IWA-6000; and

*(3)* the examinations are performed after the pressure test required by the Construction Code has been completed.

*(d)* When a vessel, liner, or a portion thereof is repaired or replaced during the service lifetime of a plant, the preservice examination requirements for the vessel repair or replacement shall be met.

*(1)* When the repair or replacement is performed while the plant is not in service, the preservice examination shall be performed prior to the resumption of service.

*(2)* When the repair or replacement is performed while the plant is in service, the preservice examination may be deferred to the next scheduled plant outage, provided nondestructive examination in accordance with the approved repair program is performed.

*(3)* When a system leakage test is required by IWE-5220, the preservice examination may be performed either prior to or following the test.

*(e)* Welds made as part of a repair or a replacement program shall be examined in accordance with the requirements of IWA-4000, except that for welds joining Class MC or Class CC components to items designed, constructed, and installed to the requirements of Section III, Class 1, 2, or 3, the examination requirements of IWB-2000, IWC-2000, or IWD-2000, as applicable, shall apply.

*(f)* Preservice examination for a repair or replacement may be conducted prior to installation provided:

*(1)* the examination is performed after the pressure test required by the Construction Code has been completed;

*(2)* the examination is conducted under conditions and with equipment and techniques equivalent to those that are expected to be employed for subsequent inservice examinations; and

*(3)* the shop or field examination records are, or can be, documented and identified in a form consistent with that required by IWA-6000.

*(g)* When paint or coatings are reapplied, the condition of the new paint or coating shall be documented in the preservice examination records.

## IWE-2400 INSPECTION SCHEDULE

### IWE-2410 INSPECTION PROGRAM

Inservice examinations and system pressure tests may be performed during plant outages such as refueling shutdowns or maintenance shutdowns. The requirements of either Inspection Program A or Inspection Program B shall be met.

#### IWE-2411 Inspection Program A

*(a)* With the exception of the examinations that may be deferred until the end of an inspection interval, as

TABLE IWE-2411-1
INSPECTION PROGRAM A

| Inspection Interval | Inspection Period, Calendar Years of Plant Service | Minimum Examinations Completed, % | Maximum Examinations Credited, % |
|---|---|---|---|
| 1st | 3 | 100 | 100 |
| 2nd | 7 | 33 | 67 |
| | 10 | 100 | 100 |
| 3rd | 13 | 16 | 34 |
| | 17 | 40 | 50 |
| | 20 | 66 | 75 |
| | 23 | 100 | 100 |
| 4th | 27 | 8 | 16 |
| | 30 | 25 | 34 |
| | 33 | 50 | 67 |
| | 37 | 75 | 100 |
| | 40 | 100 | . . . |

TABLE IWE-2412-1
INSPECTION PROGRAM B

| Inspection Interval | Inspection Period, Calendar Years of Plant Service, Within the Interval | Minimum Examinations Completed, % | Maximum Examinations Credited, % |
|---|---|---|---|
| 1st | 3 | 16 | 34 |
| | 7 | 50 | 67 |
| | 10 | 100 | 100 |
| Successive | 3 | 16 | 34 |
| | 7 | 50 | 67 |
| | 10 | 100 | 100 |

specified in Table IWE-2500-1, the required examinations shall be completed during each successive inspection interval, in accordance with Table IWE-2411-1. Following completion of Program A after 40 years, successive inspection intervals shall follow the 10 year inspection interval of Program B.

*(b)* The inspection period specified in IWE-2411(a) may be decreased or extended by as much as 1 year to enable an inspection to coincide with a plant outage, within the limitations of IWA-2430(c).

### IWE-2412 Inspection Program B

*(a)* With the exception of the examinations that may be deferred until the end of an inspection interval, as specified in Table IWE-2500-1, the required examinations shall be completed during each successive inspection interval, in accordance with Table IWE-2412-1.

*(b)* The inspection period specified in IWE-2412(a) may be decreased or extended by as much as 1 year to enable an inspection to coincide with a plant outage, within the limitations of IWA-2430(d).

## IWE-2420 SUCCESSIVE INSPECTIONS

*(a)* The sequence of component examinations established during the first inspection interval shall be repeated during each successive inspection interval, to the extent practical.

*(b)* When component examination results require evaluation of flaws, areas of degradation, or repairs in accordance with IWE-3000, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period listed in the schedule of the inspection program of IWE-2411 or IWE-2412, in accordance with Table IWE-2500-1, Examination Category E-C.

*(c)* When the reexaminations required by IWE-2420(b) reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, the areas containing such flaws, degradation, or repairs no longer require augmented examination in accordance with Table IWE-2500-1, Examination Category E-C.

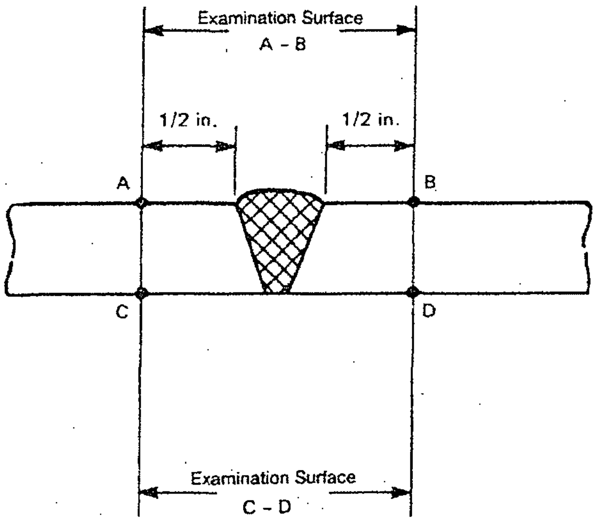
## IWE-2430 ADDITIONAL EXAMINATIONS

*(a)* Examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards of Table IWE-3410-1 shall be extended to include an additional number of examinations within the same category approximately equal to the initial number of examinations during the inspection.

*(b)* When additional flaws or areas of degradation that exceed the acceptance standards of Table IWE-3410-1 are revealed, all of the remaining examinations within the same category shall be performed to the extent specified in Table IWE-2500-1 for the inspection interval.

## IWE-2500 EXAMINATION AND PRESSURE TEST REQUIREMENTS

*(a)* The method of examination for the components, parts, and items (e.g., seals, gaskets, and bolts) of the pressure retaining boundaries shall comply with those




Surface Areas A - B and C - D

FIG. IWE-2500-1 DISSIMILAR METAL WELDS

tabulated in Table IWE-2500-1, except where alternate examination methods are used that meet the requirements of IWA-2240.

*(b)* When paint or coatings are to be removed, the paint or coatings shall be visually examined in accordance with Table IWE-2500-1 prior to removal.

*(c)* Examination methods for surface areas for augmented examination in IWE-1242 shall comply with the following criteria.

*(1)* Surface areas accessible from both sides shall be visually examined using a VT-1 visual examination method.

*(2)* Surface areas accessible from one side only shall be examined for wall thinning using an ultrasonic thickness measurement method in accordance with Section V, T-544.

*(3)* When ultrasonic thickness measurements are performed, one foot square grids shall be used. The number and location of the grids shall be determined by the Owner.

*(4)* Ultrasonic measurements shall be used to determine the minimum wall thickness within each grid. The location of the minimum wall thickness shall be marked such that periodic reexamination of that location can be performed in accordance with the requirements of Table IWE-2500-1, Examination Category E-C.

## IWE-2600 CONDITION OF SURFACE TO BE EXAMINED

*(a)* When a containment vessel or liner is painted or coated to protect surfaces from corrosion, preservice and inservice visual examinations shall be performed without the removal of the paint or coating.

*(b)* When removal of paint or coating is required, it shall be removed in a manner that will not reduce the base metal or weld thickness below the design thickness. Reapplied paint and coating systems shall be compatible with the existing system, and shall be examined in accordance with IWE-2200(g).

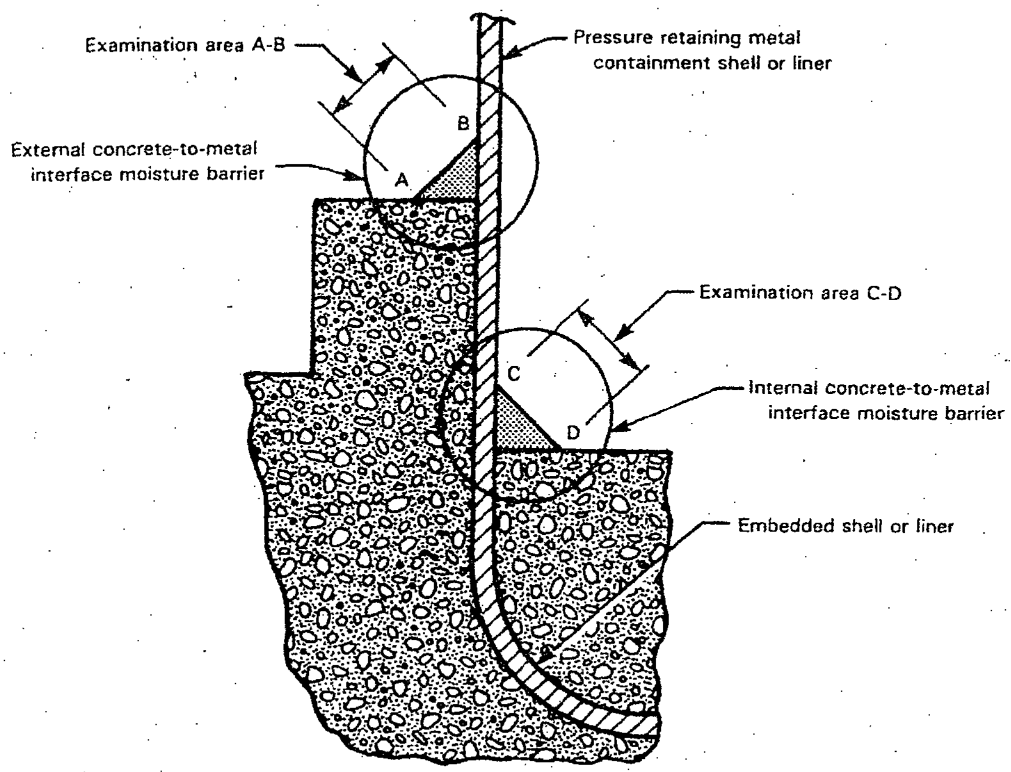



FIG. IWE-2500-2 EXAMINATION AREAS FOR MOISTURE BARRIERS

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

| EXAMINATION CATEGORY E-A, CONTAINMENT SURFACES | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | Extent and Frequency of Examination | | |
| Item No. | Parts Examined | Examination[1] Requirements/ Fig. No. | Examination Method | Acceptance Standard | 1st Inspection Interval | Successive Inspection Intervals | Deferral of Inspection to End of Interval[9] |
| E1.10 | Containment Vessel<br>Pressure Retaining Boundary | | | | ONCE EACH PERIOD PER 10CFR50.55a(b)(2)(ix)(E) | | |
| E1.11 | Accessible Surface Areas[2,3,5] | IWE-3510.1 | General Visual[7] | IWE-3510.1 | 100%<br>Prior to each Type A test[8] | 100%<br>Prior to each Type A test[8] | Not permissible |
| E1.12 | Accessible Surface Areas[2,4,5] | IWE-3510.2<br>IWE-3510.3 | Visual, VT-3 | IWE-3510.2<br>IWE-3510.3 | 100%<br>End of interval | 100%<br>End of interval | N/A |
| E1.20 | Vent System<br>Accessible Surface Areas[2,4,5,6] | IWE-3510.2<br>IWE-3510.3 | Visual, VT-3 | IWE-3510.2<br>IWE-3510.3 | 100%<br>End of interval | 100%<br>End of interval | N/A |

NOTES:
(1) Examination may be made from either the inside or outside surface.
(2) Examination shall include structures that are parts of reinforcing structure, such as stiffening rings, manhole frames, and reinforcement around openings.
(3) Not including surface areas that are submerged or insulated.
(4) Including the wetted surfaces of submerged areas and the portions of insulated surface areas that are necessary to meet the requirements of IWE-1231(a)(4).
(5) Examination shall include the attachment welds between structural attachments and the pressure retaining boundary or reinforcing structure, except for nonstructural and temporary attachments as defined in NE-4435 and minor permanent attachments as defined in CC-4543.4. Examination shall include the weld metal and the base metal for ½ in. beyond the edge of the weld.
(6) Includes flow channeling devices within containment vessels.
(7) Refer to IWE-3510.1 for General Visual examination method requirements.
(8) Refer to IWE-5220 for test requirements.
(9) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

NOT REQUIRED BY RULE

EXAMINATION CATEGORY E-B, PRESSURE RETAINING WELDS

| Item No. | Parts Examined | Examination Requirements/ Fig. No. | Examination Method | Acceptance Standard | Extent and Frequency of Examination: 1st Inspection Interval | Extent and Frequency of Examination: Successive Inspection Intervals[4] | Deferral of Inspection to End of Interval[7] |
|---|---|---|---|---|---|---|---|
| E3.10 | Containment Penetration Welds[3,5] | | Visual, VT-1 | IWE-3511 | 25% of the total number of welds[1,2] | 25% of the total number of welds[1,2] | Permissible |
| E3.11 | Longitudinal | | | | | | |
| E3.12 | Circumferential | | | | | | |
| E3.13 | Flued Head and Bellows Seal Circumferential Welds Joined to the Penetration | | | | | | |
| E3.20 | Flange Welds (Category C)[6] | | Visual, VT-1 | IWE-3511 | 25% of the total number of welds[1,2] | 25% of the total number of welds[1,2] | Permissible |
| E3.30 | Nozzle-to-Shell Welds (Category D)[6] | | Visual, VT-1 | IWE-3511 | 25% of the total number of welds[1,2] | 25% of the total number of welds[1,2] | Permissible |

NOTES:
(1) Examination shall include the weld metal and the base metal for ½ in. beyond the edge of the weld.
(2) Welds shall be randomly selected throughout the containment and representative of the type of welds described by each item number.
(3) Examination shall include welds made in accordance with Section III, Class MC, including those Class MC welds shown in Figs. NE-1120-1 and NE-1132-1.
(4) Different welds shall be selected for examination each inspection interval.
(5) Includes only those welds subject to cyclic loads and thermal stress during normal plant operation.
(6) Welded joint categories are as defined in NE-3351 for Class MC and CC-3840 for Class CC.
(7) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

| EXAMINATION CATEGORY E-C, CONTAINMENT SURFACES REQUIRING AUGMENTED EXAMINATION | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | Extent and Frequency of Examination | | |
| Item No. | Parts Examined | Examination Requirements/ Fig. No. | Examination Method | Acceptance Standard | 1st Inspection Interval | Successive Inspection Intervals | Deferral of Inspection to End of Interval[3] |
| E4.10 | Containment Surface Areas | | | | | | |
| E4.11 | Visible Surfaces | | Visual, VT-1 | IWE-3512.1<br>IWE-3512.2 | 100% of Surface Areas Identified by IWE-1242[1] | 100% of Surface Areas Identified by IWE-1242[2] | Not Permissible |
| E4.12 | Surface Area Grid, Minimum Wall Thickness Location | | Volumetric | IWE-3512.3 | 100% of Minimum Wall Thickness Locations during each Inspection Period, established in accordance with IWE-2500(c)(3)[2] and IWE-2500(c)(4)[2] | 100% of Minimum Wall Thickness Locations during each Inspection Period, established in accordance with IWE-2500(c)(3)[2] and IWE-2500(c)(4)[2] | Not Permissible |

NOTES:
(1) Containment surface areas requiring augmented examination are those identified in IWE-1240.
(2) The extent of examination shall be 100% for each inspection period until the areas examined remain essentially unchanged for three consecutive inspection periods. Such areas no longer require augmented examination in accordance with IWE-2420(c).
(3) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

4) Add Components as needed per IWE-2420

Notes
Link @ Draft Plan Category EC Notes 5 & 6

## TABLE IWE-2500-1 (CONT'D)
## EXAMINATION CATEGORIES

### EXAMINATION CATEGORY E-D, SEALS, GASKETS, AND MOISTURE BARRIERS

| Item No. | Parts Examined[1] | Examination Requirements/ Fig. No. | Examination Method | Acceptance Standard | Extent and Frequency of Examination: 1st Inspection Interval | Extent and Frequency of Examination: Successive Inspection Intervals | Deferral of Inspection to End of Interval[5] |
|---|---|---|---|---|---|---|---|
| E5.10 | Seals[1] | | Visual, VT-3 | IWE-3513 | 100% of each item | 100% of each item | Not permissible |
| E5.20 | Gaskets[1] | | Visual, VT-3 | IWE-3513 | 100% of each item | 100% of each item | Not permissible |
| E5.30 | Moisture Barriers[2,3,4] | IWE-2500-2 | Visual, VT-3 | IWE-3513 | 100% of each item | 100% of each item | Not permissible |

NOTE:
(1) Examination shall include seals and gaskets on airlocks, hatches, and other devices that are required to assure containment leak-tight integrity.
(2) Examination shall include internal and external containment moisture barrier materials at concrete-to-metal interfaces intended to prevent intrusion of moisture against the pressure retaining metal containment shell or liner.
(3) Containment moisture barrier materials include caulking, flashing, and other sealants used for this application.
(4) Examination shall include all accessible surfaces of internal and external containment moisture barriers.
(5) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

| EXAMINATION CATEGORY E-F, PRESSURE RETAINING DISSIMILAR METAL WELDS | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | Extent and Frequency of Examination | | |
| Item No. | Parts Examined[3,5] | Examination Requirements/ Fig. No. | Examination Method | Acceptance Standard | 1st Inspection Interval | Successive Inspection Intervals[4] | Deferral of Inspection to End of Interval[6] |
| E7.10 | Dissimilar Metal Welds | IWE-2500-1 | Surface | IWE-3514 | 50% of the total number of welds[1,2] | 50% of the total number of welds[1,2] | Permissible |

NOTES:

(1) Examination shall include the weld metal and the base metal for ½ in. beyond the edge of the weld.

(2) Welds shall be randomly selected throughout the containment and representative of the type of welds described by each item number.

(3) Includes dissimilar metal welds between the following combinations:

(a) carbon or low alloy steels to high alloy steels

(b) carbon or low alloy steels to high nickel alloys

(c) high alloy steels to high nickel alloys

(4) Different welds shall be selected for examination each inspection interval.

(5) Includes only those welds subject to cyclic loads and thermal stress during normal plant operation.

(6) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

**EXAMINATION CATEGORY E-G, PRESSURE RETAINING BOLTING**

| Item No. | Parts Examined | Examination Requirements/ Fig. No. | Examination Method | Acceptance Standard | Extent and Frequency of Examination: 1st Inspection Interval | Extent and Frequency of Examination: Successive Inspection Intervals | Deferral of Inspection to End of Interval[6] |
|---|---|---|---|---|---|---|---|
| E8.10 | Bolted Connections[1] | Surfaces | Visual, VT-1 | IWE-3515 | 100% of each bolted connection[2,4] | 100% of each bolted connection[2,4] | Permissible[3] |
| E8.20 | Bolted Connections | | Bolt torque or tension test[5] | IWE-3515 | 100% of bolts | 100% of bolts | Permissible |

NOTES:
(1) Examination shall include bolts, studs, nuts, bushings, washers, and threads in base material and flange ligaments between threaded stud holes.
(2) Examination of bushings, threads, and ligaments in base material of flanges is required only when the connection is disassembled.
(3) Examination shall not be deferred when the connection is disassembled or when the bolting is removed.
(4) All visible surfaces shall be examined. Bolting may remain in place under tension when disassembly is not otherwise required.
(5) Bolt torque or tension test is required only for bolted connections that have not been disassembled and reassembled during the inspection interval.
(6) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1
EXAMINATION CATEGORIES

| EXAMINATION CATEGORY E-P, ALL PRESSURE RETAINING COMPONENTS | | | | | | | |
|---|---|---|---|---|---|---|---|
| Item No. | Parts Examined | Examination/ Test Requirements | Examination Method | Acceptance Standard | Extent and Frequency of Examination: 1st Inspection Interval | Extent and Frequency of Examination: Successive Inspection Intervals | Deferral of Inspection to End of Interval |
| E9.10 | Containment Vessel Pressure Retaining Boundary[2] | System leakage test | 10 CFR 50, Appendix J | 10 CFR 50, App. J | Each repair, modification, or replacement | Each repair, modification, or replacement | Not permissible[1] |
| E9.20 | Containment Penetration Bellows | 10 CFR 50, Appendix J (Type B test) | 10 CFR 50, Appendix J | 10 CFR 50, App. J | 10 CFR 50, Appendix J | 10 CFR 50, Appendix J | Not permissible[1] |
| E9.30 | Airlocks | 10 CFR 50, Appendix J (Type B test) | 10 CFR 50, Appendix J | 10 CFR 50, App. J | 10 CFR 50, Appendix J | 10 CFR 50, Appendix J | Not permissible[1] |
| E9.40 | Seals and Gaskets | 10 CFR 50, Appendix J (Type B test) | 10 CFR 50, Appendix J | 10 CFR 50, App. J | 10 CFR 50, Appendix J | 10 CFR 50, Appendix J | Not permissible |

NOTES:
(1) Leakage tests may be deferred until the next scheduled leakage test, if allowed by IWE-5222.
(2) If leak chase channels are utilized, they shall be unplugged or tested in accordance with 10 CFR 50, Appendix J, Type B test.

# ARTICLE IWE-3000
# ACCEPTANCE STANDARDS

## IWE-3100 EVALUATION OF NONDESTRUCTIVE EXAMINATION RESULTS

### IWE-3110 PRESERVICE EXAMINATIONS

#### IWE-3111 General

The preservice examination required by IWE-2200 and performed in accordance with the procedures of IWA-2200 shall be evaluated by the acceptance standards specified in Table IWE-3410-1. Acceptance of components for service shall be in accordance with IWE-3112, IWE-3114, and IWE-3115.

#### IWE-3112 Acceptance

*(a)* Components whose examination either confirms the absence of or reveals flaws or areas of degradation that do not exceed the acceptance standards of Table IWE-3410-1 shall be acceptable for service, provided the flaws or areas of degradation are recorded in accordance with the requirements of IWA-1400(h) and IWA-6220 in terms of location, size, shape, orientation, and distribution within the component.

*(b)* Components whose examination reveals flaws or areas of degradation that do not meet the acceptance standards of Table IWE-3410-1 shall be unacceptable for service unless such flaws or areas of degradation are removed or repaired, to the extent necessary to meet the acceptance standards, prior to placement of the component in service.

#### IWE-3114 Repairs and Reexaminations

Repairs and reexaminations shall comply with the requirements of IWA-4000. Reexamination shall be conducted in accordance with the requirements of IWA-2200; the recorded results shall demonstrate that the repair meets the acceptance standards specified in Table IWE-3410-1.

#### IWE-3115 Review by Authorities

*(a)* The repair program and the examination results shall be subject to review by the enforcement authorities having jurisdiction at the plant site.

*(b)* Evaluation of examination results may be subject to review by the regulatory authority having jurisdiction at the plant site.

### IWE-3120 INSERVICE NONDESTRUCTIVE EXAMINATIONS

#### IWE-3121 General

Inservice nondestructive examination results shall be compared with recorded results of the preservice examination and prior inservice examinations. Acceptance of the components for continued service shall be in accordance with IWE-3122, IWE-3124, and IWE-3125.

#### IWE-3122 Acceptance

**IWE-3122.1 Acceptance by Examination.** Components whose examination results meet the acceptance standards listed in Table IWE-2500-1 shall be acceptable for continued service. Verified changes of flaws or areas of degradation from prior examinations shall be recorded in accordance with IWA-1400(h) and IWA-6220. Components that do not meet the acceptance standards of IWE-3000 shall be corrected in accordance with the provisions shown in IWE-3122.2, IWE-3122.3, or IWE-3122.4.

**IWE-3122.2 Acceptance by Repair.** Components whose examination results reveal flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-2500-1 shall be unacceptable for continued service until the additional examination requirements of IWE-2430 are satisfied, and the flaw or area of degradation is either removed by mechanical methods or the component repaired to the extent necessary to meet the acceptance standards of IWE-3000.

**IWE-3122.3 Acceptance by Replacement.** As an alternative to the repair requirement of IWE-3122.2, the component or the portion of the component containing the flaw or area of degradation shall be replaced in accordance with IWE-7000.

**IWE-3122.4 Acceptance by Evaluation**

*(a)* Components whose examination results reveal flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-3410-1 shall be acceptable for service without the removal or repair of the flaw or area of degradation or replacement if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. When supplemental examinations of IWE-3200 are required, if either the thickness of the base metal is reduced by no more than 10% of the nominal plate thickness or the reduced thickness can be shown by analysis to satisfy the requirements of the Design Specifications, the component shall be acceptable by evaluation.

*(b)* When flaws or areas of degradation are accepted by engineering evaluation, the area containing the flaw or degradation shall be reexamined in accordance with IWE-2420(b) and (c).

*(c)* When portions of later editions of the Construction Code or Section III are used, all related portions shall be met. The engineering evaluation shall be subject to review by the enforcement and regulatory authorities having jurisdiction at the plant site.

### IWE-3124 Repairs and Reexaminations

Repairs and reexaminations shall comply with the requirements of IWA-4000. Reexaminations shall be conducted in accordance with the requirements of IWA-2200 and the recorded results shall demonstrate that the repair meets the acceptance standards of Table IWE-3410-1.

### IWE-3125 Review by Authorities

The repair program and the reexamination results shall be subject to review by the enforcement authorities having jurisdiction at the plant site.

## IWE-3130 INSERVICE VISUAL EXAMINATIONS

Components, whose visual examination as specified in Table IWE-2500-1 reveals areas that are suspect, shall be unacceptable for continued service unless, following verification of the suspect areas by the supplemental examination as required by IWE-3200, the requirements of IWE-3120 are satisfied.

## IWE-3200 SUPPLEMENTAL EXAMINATIONS

Examinations that detect flaws or evidence of degradation that require evaluation in accordance with the requirements of IWE-3100 may be supplemented by other examination methods and techniques (IWA-2240) to determine the character of the flaw (i.e., size, shape, and orientation) or degradation. Visual examinations that detect surface flaws or areas that are suspect shall be supplemented by either surface or volumetric examination.

## IWE-3400 STANDARDS

### IWE-3410 ACCEPTANCE STANDARDS

The acceptance standards of Table IWE-3410-1 shall be applied to evaluate the acceptability of the component for service following the preservice examination and each inservice examination.

### IWE-3430 ACCEPTABILITY

Flaws or areas of degradation that do not exceed the allowable acceptance standards of IWE-3500 for the respective examination category shall be acceptable.

## IWE-3500 ACCEPTANCE STANDARDS

### IWE-3510 STANDARDS FOR EXAMINATION CATEGORY E-A, CONTAINMENT SURFACES

**IWE-3510.1 Visual Examinations — General**

*(a)* The General Visual Examination shall be performed by, or under the direction of, a Registered Professional Engineer or other individual, knowledgeable in the requirements for design, inservice inspection, and testing of Class MC and metallic liners of Class CC components. The examination shall be performed either directly or remotely, by an examiner with visual acuity sufficient to detect evidence of degradation that may affect either the containment structural integrity or leak tightness.

*(b)* Prior to proceeding with a Type A test, conditions that may affect containment structural integrity or

TABLE IWE-3410-1
ACCEPTANCE STANDARDS

| Examination Category | Component and Part Examined | Acceptance Standard |
|---|---|---|
| E-A | Containment surfaces | IWE-3510 |
| E-B | Pressure retaining welds | IWE-3511 |
| E-C | Containment surfaces requiring augmented examination | IWE-3512 |
| E-D | Seals, gaskets, and moisture barriers | IWE-3513 |
| E-F | Pressure retaining dissimilar metal welds | IWE-3514 |
| E-G | Pressure retaining bolting | IWE-3515 |
| E-P | All pressure retaining components | 10 CFR 50, Appendix J |

leak tightness shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

**IWE-3510.2 VT-3 Visual Examinations on Coated Areas.** The inspected area, when painted or coated, shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

**IWE-3510.3 VT-3 Visual Examinations on Noncoated Areas.** The inspected area shall be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

## IWE-3511 Standards for Examination Category E-B, Pressure Retaining Welds

**IWE-3511.1 VT-1 Visual Examinations on Coated Areas.** The inspected area, when painted or coated, shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

**IWE-3511.2 VT-1 Visual Examinations on Noncoated Areas.** The inspected area shall be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

## IWE-3512 Standards for Examination Category E-C, Containment Surfaces Requiring Augmented Examination

**IWE-3512.1 VT-1 Visual Examinations on Coated Areas.** The inspected area, when painted or coated, shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

**IWE-3512.2 VT-1 Visual Examinations on Noncoated Areas.** The inspected area shall be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

**IWE-3512.3 Ultrasonic Examination.** Containment vessel examinations that reveal material loss exceeding 10% of the nominal containment wall thickness, or material loss that is projected to exceed 10% of the nominal containment wall thickness prior to the next examination, shall be documented. Such areas shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

## IWE-3513 Standards for Examination Category E-D, Seals, Gaskets, and Moisture Barriers

**IWE-3513.1 VT-3 Visual Examinations.** Seals, gaskets, and moisture barriers shall be examined for wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity. Defective items shall be repaired or replaced.

## IWE-3514 Standards for Examination Category E-F, Pressure Retaining Dissimilar Metal Welds

**IWE-3514.1 Surface Examinations.** The acceptance standards of IWB-3514 shall apply within the examination boundary of Fig. IWE-2500-1.

## IWE-3515 Standards for Examination Category E-G, Pressure Retaining Bolting

**IWE-3515.1 Visual Examinations.** Bolting materials shall be examined in accordance with the material specification for defects which may cause the bolted connection to violate either the leak-tight or structural integrity. Defective items shall be replaced.

**IWE-3515.2 Bolt Torque or Bolt Tension.** Either bolt torque or bolt tension shall be within the limits specified for the original design. If no limits have been specified, acceptable bolt torque or bolt tension limits shall be determined and utilized.

# ARTICLE IWE-4000
# REPAIR PROCEDURES

## IWE-4100 SCOPE

The rules of IWA-4000 apply.

# ARTICLE IWE-5000
# SYSTEM PRESSURE TESTS

## IWE-5200 SYSTEM TEST REQUIREMENTS

### IWE-5210 GENERAL

Except as noted in IWE-5240, the requirements of IWA-5000 are not applicable to Class MC or Class CC components.

### IWE-5220 TESTS FOLLOWING REPAIR, MODIFICATION, OR REPLACEMENT

#### IWE-5221 Leakage Test

Except as noted in IWE-5222, repairs or modifications to the pressure retaining boundary or replacement of Class MC or Class CC components shall be subjected to a pneumatic leakage test in accordance with the provisions of Title 10, Part 50 of the Code of Federal Regulations, Appendix J, Paragraph IV.A, which states:

"Any major modification, replacement of a component which is part of the primary reactor containment boundary, or resealing a seal-welded door, performed after the preoperational leakage rate test shall be followed by either a Type A, Type B, or Type C test, as applicable for the area affected by the modification. The measured leakage from this test shall be included in the report to the Commission, required by V.A. The acceptance criteria of III.A.5.(b), III.B.3., or III.C.3., as appropriate, shall be met. Minor modifications, replacements, or resealing of seal-welded doors, performed directly prior to the conduct of a scheduled Type A test do not require a separate test."

#### IWE-5222 Deferral of Leakage Tests

Leakage tests for the following minor repairs or modifications to the pressure retaining boundary may be deferred until the next scheduled leakage test, provided nondestructive examination is performed in accordance with the approved repair program:

*(a)* welds of attachments to the surface of the pressure retaining boundary;

*(b)* repair cavities, the depth of which does not penetrate the required design wall by more than 10%; and

*(c)* welds attaching penetrations that are NPS 1 or smaller.

### IWE-5240 VISUAL EXAMINATION

The requirements of IWA-5246 for visual examinations are applicable.

### IWE-5250 CORRECTIVE MEASURES

If the leakage test requirements of IWE-5221 cannot be satisfied, the source of leakage shall be located and the area shall be examined to the extent necessary to establish the requirements for corrective action. Repairs shall be performed in accordance with the rules of IWE-4000 and leakage testing shall be reperformed as required by IWE-5220, prior to returning the component to service.

# ARTICLE IWE-7000
# REPLACEMENTS

## IWE-7100 GENERAL REQUIREMENTS

The rules of IWA-4000 apply.

APPLICANT'S EXHIBIT 49

# Tank Inspection, Repair, Alteration, and Reconstruction

**Refining Department**

API STANDARD 653
FIRST EDITION, JANUARY 1991

INCORPORATES SUPPLEMENT 1, JANUARY 1992



American
Petroleum
Institute

# SECTION 4—INSPECTION

## 4.1 General

Periodic in-service inspection of tanks shall be performed by an Authorized Inspector as defined herein (see 4.10), unless otherwise noted.

## 4.2 Inspection Frequency Considerations

**4.2.1** Several factors must be considered to determine inspection intervals for storage tanks. These include (but are not limited to) the following:

a. The nature of the product stored.
b. The results of visual maintenance checks.
c. Corrosion allowances and corrosion rates.
d. Corrosion prevention systems.
e. Conditions at previous inspections.
f. The methods and materials of construction and repair.
g. The location of tanks, such as those in isolated or high risk areas.
h. The potential risk of air or water pollution.
i. Leak detection systems.
j. Change in operating mode (for example: frequency of fill cycling, frequent grounding of floating roof support legs).
k. Jurisdictional requirements.

**4.2.2** The interval between inspections of a tank (both internal and external) should be determined by its service history unless special reasons indicate that an earlier inspection must be made. A history of the service of a given tank or a tank in similar service (preferably at the same site) should be available so that complete inspections can be scheduled with a frequency commensurate with the corrosion rate of the tank. On-stream, nondestructive methods of inspection shall be considered when establishing inspection frequencies.

**4.2.3** Jurisdictional regulations, in some cases, control the frequency and interval of the inspections. These regulations may include vapor loss requirements, seal condition, leakage, proper diking, and repair procedures. Knowledge of such regulations is necessary to insure compliance with scheduling and inspection requirements.

## 4.3 External Inspection

### 4.3.1 ROUTINE IN-SERVICE INSPECTIONS

**4.3.1.1** The external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This inspection may be done by owner/operator personnel, and can be done by other than inspectors described in 4.10. Personnel performing this inspection should be knowledgable of the storage facility operations, the tank, and the characteristics of the product stored.

**4.3.1.2** The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month.

**4.3.1.3** This routine in-service inspection shall include a visual inspection of the tank's exterior surface checking for: leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems and appurtenances.

### 4.3.2 SCHEDULED INSPECTIONS

**4.3.2.1** All tanks shall be given a formal visual external inspection by an inspector qualified in accordance with 4.10. at least every 5 years or at the quarter corrosion-rate life of the shell, whichever is less. Tanks may be in operation during this inspection.

**4.3.2.2** Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof.

**4.3.2.3** Where exterior tank bottom corrosion is controlled by a cathodic protection system, periodic surveys of the system shall be conducted in accordance with API RP 651.

**4.3.2.4** Tank grounding system components such as shunts or mechanical connections of cables shall be visually checked. Recommended practices dealing with the prevention of hydrocarbon ignition are covered by API RP 2003.

### 4.3.3 IN-SERVICE ULTRASONIC THICKNESS MEASUREMENTS OF THE SHELL

**4.3.3.1** External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator.

**4.3.3.2** When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following:

a. Five years after commissioning new tanks.
b. At five year intervals for existing tanks where the corrosion rate is not known.
c. When the corrosion rate is known, the maximum interval shall be the smaller of *RCA*/2*N* years (where *RCA*

is the remaining corrosion allowance in mils and $N$ is the shell corrosion rate in mils per year) or 15 years.

**4.3.3.3** Internal inspection of the tank shell, when the tank is out of service, can be substituted for a program of external ultrasonic thickness measurements (made on the shell while the tank is in service).

## 4.4 Internal Inspection

### 4.4.1 GENERAL

Internal inspection is primarily required to:

a. Ensure that the bottom is not severely corroded and leaking.
b. Gather the data necessary for the minimum bottom and shell thickness assessments detailed in Section 2. As applicable, these data shall also take into account external ultrasonic thickness measurements made during in-service inspections (see 4.3.3).
c. Identify and evaluate any tank bottom settlement.

### 4.4.2 INSPECTION INTERVALS

**4.4.2.1** Intervals between internal inspections shall be determined by the corrosion rates measured during previous inspections or anticipated based on experience with tanks in similar service. Normally, bottom corrosion rates will control and the inspection interval will be governed by the measured or anticipated corrosion rates and the calculations for minimum required thickness of tank bottoms (see 2.4.7). The actual inspection interval shall be set to ensure that the bottom plate minimum thicknesses at the next inspection are not less than the values listed in Table 4-1. In no case, however, shall the internal inspection interval exceed 20 years.

**4.4.2.2** When corrosion rates are not known and similar service experience is not available to determine the bottom plate minimum thickness at the next inspection, the actual bottom thickness shall be determined by inspection(s) within the next 10 years of tank operation to establish corrosion rates.

Table 4-1—Bottom Plate Minimum Thickness

| Minimum Bottom Plate Thickness (see 2.4.7) at Next Inspection (inches) | Tank Bottom/Foundation Design |
|---|---|
| 0.10 | Tank bottom/foundation design with no means for detection and containment of a bottom leak |
| 0.05 | Tank bottom/foundation design with means to provide detection and containment of a bottom leak |
| 0.05 | Applied tank bottom reinforced lining, > 0.05 inch thick, in accordance with API RP 652. |

### 4.4.3 ALTERNATIVE INTERNAL INSPECTION INTERVAL

For unique combinations of service, environment and construction, the owner/operator may establish the internal inspection interval using an alternative procedure. This alternative procedure shall include method for determining bottom plate thickness, consideration of environmental risk, consideration of quality of inspection and analysis of corrosion measurements. This alternative procedure shall be documented and made part of the permanent record of the tank.

## 4.5 Alternative to Internal Inspection to Determine Bottom Thickness

In cases where construction, size or other aspects allow external access to the tank bottom to determine bottom thickness, an external inspection in lieu of an internal inspection is allowed to meet the data requirements of Table 4-1. However, in these cases, consideration of other maintenance items may dictate internal inspection intervals. This alternative approach shall be documented and made part of the permanent record of the tank.

## 4.6 Preparatory Work for Internal Inspection

Specific work procedures shall be prepared and followed when conducting inspections that will assure personnel safety and health and prevent property damage in the workplace (see 1.4).

## 4.7 Inspection Checklists

Appendix C provides sample checklists of items for consideration when conducting in-service and out-of-service inspections (see Tables C-1 and C-2).

## 4.8 Records

### 4.8.1 GENERAL

Inspection records form the basis of a scheduled inspection/maintenance program. (It is recognized that records may not exist for older tanks and judgements must be based on experience with tanks in similar services.) The owner/operator shall maintain a complete record file consisting of three types of records, namely: construction records, inspection history, and repair/alteration history.

#### 4.8.2 CONSTRUCTION RECORDS

Construction records may include nameplate information, drawings, specifications, construction completion report and any results of material tests and analyses.

#### 4.8.3 INSPECTION HISTORY

The inspection history includes all measurements taken, the condition of all parts inspected, and a record of all examinations and tests. A complete description of any unusual conditions with recommendations for correction or details which caused the conditions shall also be included. This file will also contain corrosion rate and inspection interval calculations.

#### 4.8.4 REPAIR/ALTERATION HISTORY

The repair/alteration history includes all data accumulated on a tank from the time of its construction with regard to repairs, alterations, replacements, and service changes (recorded with service conditions such as stored product temperature and pressure). These records should include the results of any experiences with coatings and linings.

### 4.9 Reports

**4.9.1** Reports recommending repairs shall include reasons for the repairs, and sketches showing location and extent.

**4.9.2** General inspection reports shall include metal thickness measurements, conditions found, repairs, any settlement measurements, and recommendations.

### 4.10 Inspector Qualifications

**4.10.1** Qualified inspectors shall have education and experience equal to at least one of the following:

a. A degree in engineering plus 1 year of experience in inspection of tanks, pressure vessels or piping.
b. A 2-year certificate in engineering or technology from a technical college, and 2 years of experience in construction, repair, operation or inspection, of which one year must be in inspection of tanks, pressure vessels or piping.
c. The equivalent of a high school education, and 3 years of experience in construction, repair, operation or inspection, of which one year must be in inspection of tanks, pressure vessels or piping.
d. Five years of experience in the inspection of aboveground storage tanks in the petroleum or chemical industries.

**4.10.2** An owner/operator of tanks may designate tank inspectors qualified in accordance with 4.10.1. Such inspectors shall have the necessary authority and organizational freedom to perform their duties. Authorized Inspectors shall be certified by an agency as provided in this standard, in accordance with Appendix D. This requirement will become effective eighteen (18) months after the date of issuance of the requirement.

**4.10.3** Qualification requirements for personnel performing nondestructive examinations are identified in 10.1.1.2.

RECURRING TASK WORK ORDER

NUMBER : R2091019 ACT
PRIORITY : 5
STATUS : HISTRY 17OCT06
NBR OF ACTS: 01
LAST UPDATE: 17OCT06
PRINT DATE : 10SEP07

APPLICANT'S EXHIBIT 50

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 03

AR NUMBER : A2148837 RESPONSIBLE ORG : OPO

APPROVED BY : RITCHIE AR TYPE/SUBTYPE : RT ACT

RESP FOREMAN : SSV5 OC OPS SHIFT SUPV MUC : C

MAINT UNIT FEG : OC 1 187 000 ATTACHMENTS: N

M/U COMPONENT ID : OC 1 187 F MISC 187

MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

EQUIP REQD MODES : A QA CLASS : Q

PROCEDURE NUMBER : EQ : Y

COMPONENT UPDATE : N SAFE S/D : * ASME SECTION XI : Y

BOM/PART UPDATE : N POST MAINT TEST : N

MOD NUMBER : REPEAT/ PEP NBR : N

NEXT DUE DATE : 31OCT06 TASK FREQUENCY : 0091
TECH SPEC DATE : 22NOV06 UNIT : D

=============================== ACCOUNTING DATA ===============================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05310

OPERATING UNIT: 83

================COMMENTS - SPECIAL PROCESS/EQUIPMENT/SAFETY================

ALSO NOTE IN CREM IF WATER IS NOT PRESENT IN BOTTLE INSPECTED 25AUG06

RECURRING TASK WORK ORDER

NUMBER : R2091019 ACT
PRIORITY : 5
STATUS : HISTRY 17OCT06
NBR OF ACTS: 01
LAST UPDATE: 17OCT06
PRINT DATE : 10SEP07

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 04

===========================WORK ORDER COMPONENTS===========================

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI QQQ ASME SECTION XI: Y

QA CLASS : Q EQ : Y

============================COMPLETION VERIFICATION============================
PKG ASSMBLED : OTHER :

RESP FOREMAN : BUSK, THOMAS J REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: N COMPLETE DATE: 26AUG06
============================HISTORY VERIFICATION============================
COMPNT UPDATE : N BLIP NBR BOX: 0000
BILL OF MATLS : N FILE LOCATION:
REPEAT REQD : A/R NBR :
COMPLETED BY : BUSK, THOMAS J COMPLETE DATE: 26AUG06
CLOSED BY : GUERRAZZI, GINAMARIE HISTORY DATE : 17OCT06
CAUSE CODE : CN REPAIR CODE : NF
============================COMPLETION REMARKS============================
REPEAT MAINT: N PEP NBR: ========

**WORK PERFORMED:**

NO WATER OBSERVED IN ANY OF THE BOTTLES 26AUG06

RECURRING TASK ACTIVITY

W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT

PAGE: 01

=====DESCRIPTION=====

W/O DESCRIPTION : INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN
ACT DESCRIPTION : INSPECT POLY BOTTLES IN TORUS ROOM
PERFORMING ORG : OPO RECURRING TASK NBR: PM18705M PRI: 5
COMPONENT ID : OC 1 187 F MISC 187
EQUIPMENT LOCATION: MULTI QQQ
CLR NUMBER : QA CLASS: Q EQ: Y
WO RESP ORG : OPO FEG : OC 1 187 000
DATE/SHIFT : 26AUG06 X
FOREMAN : OC OPS SHIFT SUPV CHARGING WORK CENTER: 05310
SSV AUTH : TJB4 DATE : 25AUG06
ORG-INSP/HOLD :

ACT TYPE : C SUPPORT DATES: N/A N/A
PREPARED BY : RITCHIE DATE : 25MAY06
HOLDS : MODE N PARTS N CHEM + RAD CLR PLAN SCH

=====SAFETY/PLANT IMPACT CONSIDERATIONS=====

BARRIER PERMIT RQD: N CHEMICAL HAZARD : N CSP REQ : N
FIRE PROTECTION : N SECURITY : N FSI REQ : N
HAZARD BARRIER : N /

=====CHEM AND RAD DATA=====

SYSTEM BREACH : N INSULATION REQUIRED: N
HWP REQ : N SCAFFOLDING REQD : N TECH SPEC: N
MULTIPLE WORK LOC : MAP NBR:
HP REQD : N NO HP ASSISTANCE REQUIRED

=====SCHEDULING DATA=====

PREMIS ID : SCHED ID/WIN : 0645 187
START DATE : 07NOV06 EST DUR (HRS) : 3 POST MAINT TEST:
CLEARANCE REQD : N DUE DATE : 31OCT06 TECH SPEC: 22NOV06
DOSE ESTIMATE : 0002 mR

=====INITIAL REVIEWS=====

ASME/ISI REVIEW : BUSK ASME XI R&R: DATE: 25AUG06
QC PLAN REVIEW : BARAN NQCR - DATE: 25AUG06
APPROVED BY : BUSK DATE:

PRINT NAME AND WRITE INITIALS OF ALL PERSONNEL WHO INITIALED THIS ACTIVITY

RECURRING TASK ACTIVITY

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W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT



========================ACTIVITY PROCEDURE LIST========================

======================== HP SPECIAL INSTRUCTIONS ========================

4 RWP OC-1-06-00052 OPS AND CHEMISTRY
* THIS RWP IS NOT VALID FOR VHRA,DW OR CB/SJAE RM AT POWER.
* KNOWLEDGE OF THE RADIOLOGICAL CONDITIONS IS REQUIRED PRIOR TO ENTERING THE RCA UNLESS ESCORTED BY AN RP TECH.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* CHEMISTRY TECHNICIANS REQUIRE A DOSE RATE METER FOR ALL SYSTEM SAMPLING, EXCEPT "CLEAN" SYSTEMS,UNLESS AN AM-2 IS IN SAMPLING AREA. SAMPLES 2MR/HR OR GREATER REQUIRE RP FOR SURVEYING AND LABELING PRIOR TO TRANSPORTING.
* OPERATORS SHALL NOTIFY RP BEFORE PERFORMING ANY ACTIVITES THAT COULD RESULT IN CHANGING AREA DOSE RATES. EXAMPLES INCLUDE DRAINING SYSTEM OR COMPONENT THAT CONTAINS RADIOACTIVITY (TANKS, FILTERS, PIPING, ETC.)

RECURRING TASK ACTIVITY

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W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT



====================== ACTIVITY FOLLOWER DESCRIPTION ======================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | 1. PURPOSE: | | |
| | A. THE PURPOSE OF THIS ACTIVITY IS INSPECT THE POLY BOTTLES IN THE TORUS ROOM FOR THE PRESENCE OF WATER. | | |
| | . | | |
| | 2. CLEARANCE REQUIREMENTS: | | |
| | A. NONE | | |
| | . | | |
| | 3. OPS IMPACT STATEMENT: | | |
| | A. NONE. | | |
| | . | | |
| | 4. PRECAUTIONS | | |
| | A. USE EXTREME CAUTION WHEN WORKING ON OR NEAR ROTATING EQUIPMENT. REFERENCE THE MID-ATLANTIC ROG SAFETY AND HEALTH GUIDE AND PROCEDURE EN-OC-301 FOR CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS WORK. | | |
| | B. BE SURE A PRE-JOB BRIEF IS PERFORMED AND ALL CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS ACTIVITY ARE PROPERLY ADDRESSED AND ANY AND ALL CONCERNS AND QUESTIONS | | |

RECURRING TASK ACTIVITY

W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT



==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|

HAVE BEEN RESOLVED BEFORE STARTING WORK.

.

5. SUPPORT INFORMATION

. A. NONE

.

6. JOB SCOPE

A. INSPECTION OF POLY BOTTLES INSIDE THE TORUS ROOM. THERE ARE 5 POLY BOTTLES LOCATED AROUND THE OUTER PERIMETER OF THE TORUS. THE INSPECTION SHALL INCLUDE CHECKING FOR THE PRESENCE OF WATER IN THE BOTTLES. DOCUMENT IN THE CREM IF WATER IS PRESENT, AND IF SO, WHAT IS THE LEVEL IN THE BOTTLE AND THE LOCATION OF THE BOTTLE (BY BAY NUMBER).

B. IF BOTTLE IS OVER 3/4 FULL, NOTE LEVEL AND DUMP BOTTLE INTO NEAREST FLOOR DRAIN.

RECURRING TASK ACTIVITY

W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT

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==============================SUMMARY COMMENTS:==============================

CAUSE CODE: __ __ __ REPAIR CODE: __ __ __

ADDITIONAL PAGES ATTACHED ? ___ ETT REMOVED ? ___

======================MEASUREMENT AND TEST EQUIPMENT======================

| ID NUMBER | DATE USED | DESCRIPTION | ADDITIONAL PAGES ATTACHED ? ___ |
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==============================FINAL REVIEWS==============================

MAINT ______________________ DATE : ______________

QC ______________________ DATE : ______________

OTHER ______________________ DATE : ______________

RECURRING TASK ACTIVITY

W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT

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## MEASUREMENT AND TEST EQUIPMENT

| ACTIVITY | ID NUMBER | DATE USED | DESCRIPTION |
|---|---|---|---|
| 01 | NONE | N/A | |

RECURRING TASK ACTIVITY

W/O NBR : R2091019 01
A/R NBR : A2148837
W/O STATUS : HISTRY 17OCT06
ACT STATUS : HISTRY 17OCT06
TYPE : ACT

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RECURRING TASK WORK ORDER

NUMBER : R2091083 ACT
PRIORITY : 5
STATUS : HISTRY 29NOV06
NBR OF ACTS: 01
LAST UPDATE: 29NOV06
PRINT DATE : 10SEP07

APPLICANT'S EXHIBIT 51

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 03

AR NUMBER : A2148940 RESPONSIBLE ORG : OPO

APPROVED BY : RITCHIE AR TYPE/SUBTYPE : RT ACT

RESP FOREMAN : SSV5 OC OPS SHIFT SUPV MUC : C

MAINT UNIT FEG : OC 1 187 000 ATTACHMENTS: N

M/U COMPONENT ID : OC 1 187 F MISC 187

MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

EQUIP REQD MODES : A QA CLASS : Q

PROCEDURE NUMBER : EQ : Y

COMPONENT UPDATE : N SAFE S/D : * ASME SECTION XI : Y

BOM/PART UPDATE : N POST MAINT TEST : N

MOD NUMBER : REPEAT/ PEP NBR : N

NEXT DUE DATE : 25NOV06 TASK FREQUENCY : 0091
TECH SPEC DATE : 17DEC06 UNIT : D

================================ ACCOUNTING DATA ================================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05310

OPERATING UNIT: 83

================================================================================

RECURRING TASK WORK ORDER

NUMBER : R2091083 ACT
PRIORITY : 5
STATUS : HISTRY 29NOV06
NBR OF ACTS: 01
LAST UPDATE: 29NOV06
PRINT DATE : 10SEP07

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 04

=====WORK ORDER COMPONENTS=====

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI OOO ASME SECTION XI: Y

QA CLASS : Q EQ : Y

=====COMPLETION VERIFICATION=====

PKG ASSMBLED : HGT0 TRITT, HERBERT G OTHER :

RESP FOREMAN : TRITT, HERBERT G REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: N COMPLETE DATE: 25NOV06

=====HISTORY VERIFICATION=====

COMPNT UPDATE : N BLIP NBR BOX: 0000
BILL OF MATLS : N FILE LOCATION:
REPEAT REQD : A/R NBR :
COMPLETED BY : TRITT, HERBERT G COMPLETE DATE: 25NOV06
CLOSED BY : GUERRAZZI, GINAMARIE HISTORY DATE : 29NOV06
CAUSE CODE : CN REPAIR CODE : PM

=====COMPLETION REMARKS=====

REPEAT MAINT: N PEP NBR: ========

**WORK PERFORMED:**

A01---ALL POLY BOTTLES WERE FOUND WITH NO WATER IN THEM 25NOV06

RECURRING TASK ACTIVITY

W/O NBR : R2091083 01
A/R NBR : A2148940
W/O STATUS : HISTRY 29NOV06
ACT STATUS : HISTRY 29NOV06
TYPE : ACT



## DESCRIPTION

W/O DESCRIPTION : INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN
ACT DESCRIPTION : INSPECT POLY BOTTLES IN TORUS ROOM
PERFORMING ORG : OPO RECURRING TASK NBR: PM18705M PRI: 5
COMPONENT ID : OC 1 187 F MISC 187
EQUIPMENT LOCATION: MULTI QQQ
CLR NUMBER : QA CLASS: Q EQ: Y
WO RESP ORG : OPO FEG : OC 1 187 000
DATE/SHIFT : 25NOV06 X
FOREMAN : OC OPS SHIFT SUPV CHARGING WORK CENTER: 05310
SSV AUTH : CRW1 DATE : 13NOV06
ORG-INSP/HOLD :

ACT TYPE : C SUPPORT DATES: N/A N/A
PREPARED BY : RITCHIE DATE : 25MAY06
HOLDS : MODE N PARTS N CHEM + RAD CLR PLAN SCH

## SAFETY/PLANT IMPACT CONSIDERATIONS

BARRIER PERMIT RQD: N CHEMICAL HAZARD : N CSP REQ : N
FIRE PROTECTION : N SECURITY : N FSI REQ : N
HAZARD BARRIER : N /

## CHEM AND RAD DATA

SYSTEM BREACH : N INSULATION REQUIRED: N
HWP REQ : N SCAFFOLDING REQD : N TECH SPEC: N
MULTIPLE WORK LOC : MAP NBR:
HP REQD : N NO HP ASSISTANCE REQUIRED

## SCHEDULING DATA

PREMIS ID : 0646 187 SCHED ID/WIN : 0646 187
START DATE : 25NOV06 EST DUR (HRS) : 3 POST MAINT TEST:
CLEARANCE REQD : N DUE DATE : 25NOV06 TECH SPEC: 17DEC06
DOSE ESTIMATE : 0002 mR

## INITIAL REVIEWS

ASME/ISI REVIEW : RITCHIE ASME XI R&R: DATE: 06OCT06
QC PLAN REVIEW : BARAN NQCR - DATE: 24JUL06
APPROVED BY : RITCHIE, J DATE:

PRINT NAME AND WRITE INITIALS OF ALL PERSONNEL WHO INITIALED THIS ACTIVITY

RECURRING TASK ACTIVITY

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W/O NBR : R2091083 01
A/R NBR : A2148940
W/O STATUS : HISTRY 29NOV06
ACT STATUS : HISTRY 29NOV06
TYPE : ACT



=========================ACTIVITY PROCEDURE LIST=============================

========================= HP SPECIAL INSTRUCTIONS ==========================

4 RWP OC-1-06-00052 OPS AND CHEMISTRY

* THIS RWP IS NOT VALID FOR VHRA,DW OR CB/SJAE RM AT POWER.
* KNOWLEDGE OF THE RADIOLOGICAL CONDITIONS IS REQUIRED PRIOR TO ENTERING THE RCA UNLESS ESCORTED BY AN RP TECH.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* CHEMISTRY TECHNICIANS REQUIRE A DOSE RATE METER FOR ALL SYSTEM SAMPLING, EXCEPT "CLEAN" SYSTEMS,UNLESS AN AM-2 IS IN SAMPLING AREA. SAMPLES 2MR/HR OR GREATER REQUIRE RP FOR SURVEYING AND LABELING PRIOR TO TRANSPORTING.
* OPERATORS SHALL NOTIFY RP BEFORE PERFORMING ANY ACTIVITES THAT COULD RESULT IN CHANGING AREA DOSE RATES. EXAMPLES INCLUDE DRAINING SYSTEM OR COMPONENT THAT CONTAINS RADIOACTIVITY (TANKS, FILTERS, PIPING, ETC.)

RECURRING TASK ACTIVITY

W/O NBR : R2091083 01
A/R NBR : A2148940
W/O STATUS : HISTRY 29NOV06
ACT STATUS : HISTRY 29NOV06
TYPE : ACT



==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|

1. PURPOSE:

   A. THE PURPOSE OF THIS ACTIVITY IS INSPECT THE POLY BOTTLES IN THE TORUS ROOM FOR THE PRESENCE OF WATER.

.

2. CLEARANCE REQUIREMENTS:

   A. NONE

.

3. OPS IMPACT STATEMENT:

   A. NONE.

.

4. PRECAUTIONS

   A. USE EXTREME CAUTION WHEN WORKING ON OR NEAR ROTATING EQUIPMENT. REFERENCE THE MID-ATLANTIC ROG SAFETY AND HEALTH GUIDE AND PROCEDURE EN-OC-301 FOR CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS WORK.

   B. BE SURE A PRE-JOB BRIEF IS PERFORMED AND ALL CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS ACTIVITY ARE PROPERLY ADDRESSED AND ANY AND ALL CONCERNS AND QUESTIONS

RECURRING TASK ACTIVITY

W/O NBR : R2091083 01
A/R NBR : A2148940
W/O STATUS : HISTRY 29NOV06
ACT STATUS : HISTRY 29NOV06
TYPE : ACT



==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | HAVE BEEN RESOLVED BEFORE STARTING WORK. | | |
| | . | | |
| | 5. SUPPORT INFORMATION | | |
| | . A. NONE | | |
| | . | | |
| | 6. JOB SCOPE | | |
| | A. INSPECTION OF POLY BOTTLES INSIDE THE TORUS | | |
| | ROOM. THERE ARE 5 POLY BOTTLES LOCATED | | |
| | AROUND THE OUTER PERIMETER OF THE TORUS. | | |
| | THE INSPECTION SHALL INCLUDE CHECKING FOR | | |
| | THE PRESENCE OF WATER IN THE BOTTLES. | | |
| | DOCUMENT IN THE CREM IF WATER IS PRESENT, | | |
| | AND IF SO, WHAT IS THE LEVEL IN THE BOTTLE | | |
| | AND THE LOCATION OF THE BOTTLE (BY BAY | | |
| | NUMBER). | | |
| | B. IF BOTTLE IS OVER 3/4 FULL, NOTE LEVEL | | |
| | AND DUMP BOTTLE INTO NEAREST FLOOR DRAIN. | | |

RECURRING TASK ACTIVITY

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W/O NBR : R2091083 01
A/R NBR : A2148940
W/O STATUS : HISTRY 29NOV06
ACT STATUS : HISTRY 29NOV06
TYPE : ACT

PAGE: 05

==============================SUMMARY COMMENTS:==============================

CAUSE CODE: ___ ___ ___ REPAIR CODE: ___ ___ ___

ADDITIONAL PAGES ATTACHED ? ___ ETT REMOVED ? ___

======================MEASUREMENT AND TEST EQUIPMENT======================

| ID NUMBER | DATE USED | DESCRIPTION | ADDITIONAL PAGES ATTACHED ? ___ |
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==============================FINAL REVIEWS==============================

MAINT ______________________ DATE : ______________

QC ______________________ DATE : ______________

OTHER ______________________ DATE : ______________

RECURRING TASK WORK ORDER

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NUMBER : R2095404 ACT
PRIORITY : 5
STATUS : HISTRY 20FEB07
NBR OF ACTS: 01
LAST UPDATE: 20FEB07
PRINT DATE : 10SEP07

APPLICANT'S EXHIBIT 52

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 03

| | |
|---|---|
| AR NUMBER : A2155763 | RESPONSIBLE ORG : OPO |
| APPROVED BY : RITCHIE | AR TYPE/SUBTYPE : RT ACT |
| RESP FOREMAN : SSV5 OC OPS SHIFT SUPV | MUC : C |
| MAINT UNIT FEG : OC 1 187 000 | ATTACHMENTS: N |
| M/U COMPONENT ID : OC 1 187 F MISC 187 | |
| MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL) | |
| EQUIP REQD MODES : A | QA CLASS : Q |
| PROCEDURE NUMBER : | EQ : Y |
| COMPONENT UPDATE : N SAFE S/D : * | ASME SECTION XI : Y |
| BOM/PART UPDATE : N | POST MAINT TEST : N |
| MOD NUMBER : | REPEAT/ PEP NBR : N |
| NEXT DUE DATE : 24FEB07 | TASK FREQUENCY : 0091 |
| TECH SPEC DATE : 18MAR07 | UNIT : D |

===================== ACCOUNTING DATA =====================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05310

OPERATING UNIT: 83

==========================================================

RECURRING TASK WORK ORDER

NUMBER : R2095404 ACT
PRIORITY : 5
STATUS : HISTRY 20FEB07
NBR OF ACTS: 01
LAST UPDATE: 20FEB07
PRINT DATE : 10SEP07

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 04

===========================WORK ORDER COMPONENTS============================

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI QQQ ASME SECTION XI: Y

QA CLASS : Q EQ : Y

============================COMPLETION VERIFICATION===========================

PKG ASSMBLED : OTHER :

RESP FOREMAN : SISAK, JOSHUA V REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: N COMPLETE DATE: 13FEB07

===========================HISTORY VERIFICATION==============================

COMPNT UPDATE : N BLIP NBR BOX: 0000
BILL OF MATLS : N FILE LOCATION:
REPEAT REQD : A/R NBR :
COMPLETED BY : SISAK, JOSHUA V COMPLETE DATE: 13FEB07
CLOSED BY : GUERRAZZI, GINAMARIE HISTORY DATE : 20FEB07
CAUSE CODE : CN REPAIR CODE : NF

===========================COMPLETION REMARKS================================

REPEAT MAINT: N PEP NBR: ========

**WORK PERFORMED:**

A01 INSPECTED POLY BOTTLES FOR WATER. NO WATER PRESENT. JVS3 13FEB07

RECURRING TASK ACTIVITY

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W/O NBR : R2095404 01
A/R NBR : A2155763
W/O STATUS : HISTRY 20FEB07
ACT STATUS : HISTRY 20FEB07
TYPE : ACT

RWP ACCESS CODE: OC-1-07-00052 PAGE: 01

=====DESCRIPTION=====

W/O DESCRIPTION : INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN
ACT DESCRIPTION : INSPECT POLY BOTTLES IN TORUS ROOM
PERFORMING ORG : OPO RECURRING TASK NBR: PM18705M PRI: 5
COMPONENT ID : OC 1 187 F MISC 187
EQUIPMENT LOCATION: MULTI QQQ
CLR NUMBER : ____ QA CLASS: Q EQ: Y
WO RESP ORG : OPO FEG : OC 1 187 000
DATE/SHIFT : 13FEB07 X
FOREMAN : OC OPS SHIFT SUPV CHARGING WORK CENTER: 05310
SSV AUTH : PXG1 DATE : 12FEB07
ORG-INSP/HOLD :

ACT TYPE : C SUPPORT DATES: N/A N/A
PREPARED BY : RITCHIE DATE : 25MAY06
HOLDS : MODE N PARTS N CHEM + RAD ___ CLR ___ PLAN ___ SCH ___

=====SAFETY/PLANT IMPACT CONSIDERATIONS=====

BARRIER PERMIT RQD: N CHEMICAL HAZARD : N CSP REQ : N
FIRE PROTECTION : N SECURITY : N FSI REQ : N
HAZARD BARRIER : N / ____

=====CHEM AND RAD DATA=====

SYSTEM BREACH : N INSULATION REQUIRED: N
HWP REQ : N SCAFFOLDING REQD : N TECH SPEC: N
MULTIPLE WORK LOC : ___ MAP NBR: ____
HP REQD : N NO HP ASSISTANCE REQUIRED

=====SCHEDULING DATA=====

PREMIS ID : 0707 187 SCHED ID/WIN : 0707 187
START DATE : 13FEB07 EST DUR (HRS) : 3 POST MAINT TEST: ___
CLEARANCE REQD : N DUE DATE : 24FEB07 TECH SPEC: 18MAR07
DOSE ESTIMATE : 0002 mR

=====INITIAL REVIEWS=====

ASME/ISI REVIEW : VOISHNIS, G ASME XI R&R: ___ DATE: 09FEB07
QC PLAN REVIEW : VOISHNIS, G NQCR ___ - ___ DATE: 09FEB07
APPROVED BY : VOISHNIS, G DATE: ____

PRINT NAME AND WRITE INITIALS OF ALL PERSONNEL WHO INITIALED THIS ACTIVITY

RECURRING TASK ACTIVITY

W/O NBR : R2095404 01
A/R NBR : A2155763
W/O STATUS : HISTRY 20FEB07
ACT STATUS : HISTRY 20FEB07
TYPE : ACT



==========================ACTIVITY PROCEDURE LIST==========================

======================= RAD PROTECTION REQUIREMENTS =======================

ALARMING DOSIMETER: Y

ED SETPOINT: 0032 MREM or 0300 MREM/HR

HP COVERAGE: INTERMITTENT

RWP ACCESS CODE: OC-1-07-00052

======================== HP SPECIAL INSTRUCTIONS ========================

* OPERATIONS.
* THIS RWP IS NOT VALID FOR VHRA,DW OR CB/SJAE RM AT POWER.
* KNOWLEDGE OF RAD CONDITIONS REQ'D PRIOR TO ENTRY TO RCA W/OUT RPT ESCORT.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* OPERATORS SHALL NOTIFY RP BEFORE PERFORMING ANY ACTIVITES THAT COULD RESULT IN CHANGING AREA DOSE RATES. EXAMPLES INCLUDE DRAINING SYSTEM OR COMPONENT THAT CONTAINS RADIOACTIVITY (TANKS, FILTERS, PIPING, ETC.)

OPEX:
\- CLEARANCE AND TAGGING ACTIVITIES-FAILURE TO ADHERE TO OR INADEQUATE TAGOUT INSTRUCTIONS HAVE CONTRIBUTED TO LOSSES IN GENERATION AND HAZARDOUS WORKING CONDITIONS.OE #S:OE20012,OE20535,OE19214.

RECURRING TASK ACTIVITY

W/O NBR : R2095404 01
A/R NBR : A2155763
W/O STATUS : HISTRY 20FEB07
ACT STATUS : HISTRY 20FEB07
TYPE : ACT



==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|

NOTE:

WHEN THE PM IS PERFORMED IN WEEK 0707 CURRENTLY SCHEDULED FOR 2/13/2007, ENSURE TIM RAUSCH AND PETE TAMBURRO GO ALONG.

****

****

1. PURPOSE:

A. THE PURPOSE OF THIS ACTIVITY IS INSPECT THE POLY BOTTLES IN THE TORUS ROOM FOR THE PRESENCE OF WATER.

.

2. CLEARANCE REQUIREMENTS:

A. NONE

.

3. OPS IMPACT STATEMENT:

A. NONE.

.

4. PRECAUTIONS

A. USE EXTREME CAUTION WHEN WORKING ON OR NEAR ROTATING EQUIPMENT. REFERENCE THE MID-ATLANTIC ROG SAFETY AND HEALTH GUIDE AND PROCEDURE EN-OC-301 FOR

==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS WORK. | | |
| | B. BE SURE A PRE-JOB BRIEF IS PERFORMED AND ALL CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS ACTIVITY ARE PROPERLY ADDRESSED AND ANY AND ALL CONCERNS AND QUESTIONS HAVE BEEN RESOLVED BEFORE STARTING WORK. | | |
| | . | | |
| | 5. SUPPORT INFORMATION | | |
| | . A. NONE | | |
| | . | | |
| | 6. JOB SCOPE | | |
| | A. INSPECTION OF POLY BOTTLES INSIDE THE TORUS ROOM. THERE ARE 5 POLY BOTTLES LOCATED AROUND THE OUTER PERIMETER OF THE TORUS. THE INSPECTION SHALL INCLUDE CHECKING FOR THE PRESENCE OF WATER IN THE BOTTLES. DOCUMENT IN THE CREM IF WATER IS PRESENT, AND IF SO, WHAT IS THE LEVEL IN THE BOTTLE AND THE LOCATION OF THE BOTTLE (BY BAY NUMBER). | | |
| | . | | |

===================== ACTIVITY FOLLOWER DESCRIPTION =====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | B. IF WATER IS FOUND IN ANY OF THE POLY BOTTLES, PERFORM THE FOLLOWING: | | |
| | - INVESTIGATE AND FIND THE SOURCE. | | |
| | - REQUEST A CHEMISTRY SAMPLE. DO NOT EMPTY ANY BOTTLES UNTIL A SAMPLE HAS BEEN TAKEN. | | |
| | - ISSUE IR | | |
| | - IDENTIFY BY BAY NUMBER WHICH BOTTLES HAVE WATER AND INDICATE THE LEVEL IN THE BOTTLE. | | |
| | C. EMPTY BOTTLE AS DIRECTED BY ENGINEERING | | |

RECURRING TASK ACTIVITY

W/O NBR : R2095404 01
A/R NBR : A2155763
W/O STATUS : HISTRY 20FEB07
ACT STATUS : HISTRY 20FEB07
TYPE : ACT

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==============================SUMMARY COMMENTS:==============================

CAUSE CODE: __ __ __ REPAIR CODE: __ __ __

ADDITIONAL PAGES ATTACHED ? ____ ETT REMOVED ? ____

=====================MEASUREMENT AND TEST EQUIPMENT=====================

| ID NUMBER | DATE USED | DESCRIPTION | ADDITIONAL PAGES ATTACHED ? ___ |
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=============================FINAL REVIEWS=============================

MAINT ____________________ DATE : ____________

QC ____________________ DATE : ____________

OTHER ____________________ DATE : ____________

RECURRING TASK ACTIVITY

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W/O NBR : R2095404 01
A/R NBR : A2155763
W/O STATUS : HISTRY 20FEB07
ACT STATUS : HISTRY 20FEB07
TYPE : ACT



MEASUREMENT AND TEST EQUIPMENT

| ACTIVITY | ID NUMBER | DATE USED | DESCRIPTION |
|---|---|---|---|
| 01 | NONE | N/A | |

RECURRING TASK ACTIVITY

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W/O NBR : R2095404 01
A/R NBR : A2155763
W/O STATUS : HISTRY 20FEB07
ACT STATUS : HISTRY 20FEB07
TYPE : ACT

RECURRING TASK WORK ORDER

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  **      **********   **        **
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NUMBER : R2099351 ACT
PRIORITY : 5
STATUS : HISTRY 22JUN07
NBR OF ACTS: 01
LAST UPDATE: 22JUN07
PRINT DATE : 10SEP07

APPLICANT'S EXHIBIT 53

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 03

AR NUMBER : A2161370 RESPONSIBLE ORG : OPO

APPROVED BY : RITCHIE AR TYPE/SUBTYPE : RT ACT

RESP FOREMAN : GJV0 VOISHNIS JR., GEORGE MUC : C

MAINT UNIT FEG : OC 1 187 000 ATTACHMENTS: N

M/U COMPONENT ID : OC 1 187 F MISC 187

MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

EQUIP REQD MODES : A QA CLASS : Q

PROCEDURE NUMBER : EQ : Y

COMPONENT UPDATE : N SAFE S/D : * ASME SECTION XI : Y

BOM/PART UPDATE : N POST MAINT TEST : N

MOD NUMBER : REPEAT/ PEP NBR : N

NEXT DUE DATE : 15MAY07 TASK FREQUENCY : 0091
TECH SPEC DATE : 06JUN07 UNIT : D

=============================== ACCOUNTING DATA ===============================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05310

OPERATING UNIT: 83

==============================================================================

RECURRING TASK WORK ORDER

NUMBER : R2099351 ACT
PRIORITY : 5
STATUS : HISTRY 22JUN07
NBR OF ACTS: 01
LAST UPDATE: 22JUN07
PRINT DATE : 10SEP07

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 04

==========================WORK ORDER COMPONENTS==========================

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI OOO ASME SECTION XI: Y

QA CLASS : Q EQ : Y

==========================COMPLETION VERIFICATION==========================

PKG ASSMBLED : JCR0 RUMBIN, JAMES C OTHER :

RESP FOREMAN : RUMBIN, JAMES C REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: N COMPLETE DATE: 22MAY07

==========================HISTORY VERIFICATION==========================

COMPNT UPDATE : N BLIP NBR BOX: 0000
BILL OF MATLS : N FILE LOCATION:
REPEAT REQD : A/R NBR :
COMPLETED BY : RUMBIN, JAMES C COMPLETE DATE: 22MAY07
CLOSED BY : ROSANIO, CLAIRE M HISTORY DATE : 22JUN07
CAUSE CODE : CN REPAIR CODE : PM

==========================COMPLETION REMARKS==========================

REPEAT MAINT: N PEP NBR: ========

**WORK PERFORMED:**

NO WATER IN ANY OF THE 5 BOTTLES-----JIM RUMBIN 22MAY07

RECURRING TASK ACTIVITY

W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT

RWP ACCESS CODE: OC-1-07-00052 PAGE: 01

==============================DESCRIPTION==============================

W/O DESCRIPTION : INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN
ACT DESCRIPTION : INSPECT POLY BOTTLES IN TORUS ROOM
PERFORMING ORG : OPO RECURRING TASK NBR: PM18705M PRI: 5
COMPONENT ID : OC 1 187 F MISC 187
EQUIPMENT LOCATION: MULTI QQQ
CLR NUMBER : QA CLASS: Q EQ: Y
WO RESP ORG : OPO FEG : OC 1 187 000
DATE/SHIFT : 22MAY07 X
FOREMAN : OC OPS SHIFT SUPV CHARGING WORK CENTER: 05310
SSV AUTH : RFS0 DATE : 21MAY07
ORG-INSP/HOLD :

ACT TYPE : C SUPPORT DATES: N/A N/A
PREPARED BY : RITCHIE DATE : 25MAY06
HOLDS : MODE N PARTS N CHEM + RAD CLR PLAN SCH

==================SAFETY/PLANT IMPACT CONSIDERATIONS==================

BARRIER PERMIT RQD: N CHEMICAL HAZARD : N CSP REQ : N
FIRE PROTECTION : N SECURITY : N FSI REQ : N
HAZARD BARRIER : N /

==========================CHEM AND RAD DATA==========================

SYSTEM BREACH : N INSULATION REQUIRED: N
HWP REQ : N SCAFFOLDING REQD : N TECH SPEC: N
MULTIPLE WORK LOC : MAP NBR:
HP REQD : N NO HP ASSISTANCE REQUIRED

===========================SCHEDULING DATA===========================

PREMIS ID : 0721 187 SCHED ID/WIN : 0721 187
START DATE : 22MAY07 EST DUR (HRS) : 3 POST MAINT TEST:
CLEARANCE REQD : N DUE DATE : 15MAY07 TECH SPEC: 06JUN07
DOSE ESTIMATE : 0002 mR

===========================INITIAL REVIEWS===========================

ASME/ISI REVIEW : VOISHNIS, G ASME XI R&R: DATE: 24APR07
QC PLAN REVIEW : VOISHNIS, G NQCR - DATE: 24APR07
APPROVED BY : VOISHNIS, G DATE:

=====================================================================

PRINT NAME AND WRITE INITIALS OF ALL PERSONNEL WHO INITIALED THIS ACTIVITY

RECURRING TASK ACTIVITY

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W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT



========================ACTIVITY PROCEDURE LIST============================

====================== RAD PROTECTION REQUIREMENTS ======================

ALARMING DOSIMETER: Y

ED SETPOINT: 0032 MREM or 0300 MREM/HR

HP COVERAGE: INTERMITTENT

RWP ACCESS CODE: OC-1-07-00052

======================== HP SPECIAL INSTRUCTIONS ========================

* OPERATIONS.
* THIS RWP IS NOT VALID FOR VHRA,DW OR CB/SJAE RM AT POWER.
* KNOWLEDGE OF RAD CONDITIONS REQ'D PRIOR TO ENTRY TO RCA W/OUT RPT ESCORT.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* OPERATORS SHALL NOTIFY RP BEFORE PERFORMING ANY ACTIVITES THAT COULD RESULT IN CHANGING AREA DOSE RATES. EXAMPLES INCLUDE DRAINING SYSTEM OR COMPONENT THAT CONTAINS RADIOACTIVITY (TANKS, FILTERS, PIPING, ETC.)

OPEX:

- CLEARANCE AND TAGGING ACTIVITIES-FAILURE TO ADHERE TO OR INADEQUATE TAGOUT INSTRUCTIONS HAVE CONTRIBUTED TO LOSSES IN GENERATION AND HAZARDOUS WORKING CONDITIONS.OE #S:OE20012,OE20535,OE19214.

RECURRING TASK ACTIVITY

W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT



==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INITIAL/DATE INSP |
|---|---|---|---|

1. PURPOSE:

   A. THE PURPOSE OF THIS ACTIVITY IS INSPECT THE POLY BOTTLES IN THE TORUS ROOM FOR THE PRESENCE OF WATER.

   .

2. CLEARANCE REQUIREMENTS:

   A. NONE

   .

3. OPS IMPACT STATEMENT:

   A. NONE.

   .

4. PRECAUTIONS

   A. USE EXTREME CAUTION WHEN WORKING ON OR NEAR ROTATING EQUIPMENT. REFERENCE THE MID-ATLANTIC ROG SAFETY AND HEALTH GUIDE AND PROCEDURE EN-OC-301 FOR CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS WORK.

   B. BE SURE A PRE-JOB BRIEF IS PERFORMED AND ALL CAUTIONS AND PRECAUTIONS ASSOCIATED WITH THIS ACTIVITY ARE PROPERLY ADDRESSED AND ANY AND ALL CONCERNS AND QUESTIONS

RECURRING TASK ACTIVITY

W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT



==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|

HAVE BEEN RESOLVED BEFORE STARTING WORK.

.

5. SUPPORT INFORMATION

. A. NONE

.

6. JOB SCOPE

A. INSPECTION OF POLY BOTTLES INSIDE THE TORUS ROOM. THERE ARE 5 POLY BOTTLES LOCATED AROUND THE OUTER PERIMETER OF THE TORUS. THE INSPECTION SHALL INCLUDE CHECKING FOR THE PRESENCE OF WATER IN THE BOTTLES. DOCUMENT IN THE CREM IF WATER IS PRESENT, AND IF SO, WHAT IS THE LEVEL IN THE BOTTLE AND THE LOCATION OF THE BOTTLE (BY BAY NUMBER).

.

B. IF WATER IS FOUND IN ANY OF THE POLY BOTTLES, PERFORM THE FOLLOWING:

- INVESTIGATE AND FIND THE SOURCE.
- REQUEST A CHEMISTRY SAMPLE. DO NOT EMPTY ANY BOTTLES UNTIL A SAMPLE HAS BEEN TAKEN.

RECURRING TASK ACTIVITY

W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT



===================== ACTIVITY FOLLOWER DESCRIPTION =====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | - ISSUE IR | | |
| | - IDENTIFY BY BAY NUMBER WHICH BOTTLES HAVE WATER AND INDICATE THE LEVEL IN THE BOTTLE. | | |
| | C. EMPTY BOTTLE AS DIRECTED BY ENGINEERING | | |

RECURRING TASK ACTIVITY

W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT



==============================SUMMARY COMMENTS:==============================

CAUSE CODE: ___ ___ ___ REPAIR CODE: ___ ___ ___

ADDITIONAL PAGES ATTACHED ? ____ ETT REMOVED ? ____

======================MEASUREMENT AND TEST EQUIPMENT======================

| ID NUMBER | DATE USED | DESCRIPTION | ADDITIONAL PAGES ATTACHED ? ___ |
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==============================FINAL REVIEWS==============================

MAINT ____________________ DATE : ____________

QC ____________________ DATE : ____________

OTHER ____________________ DATE : ____________

RECURRING TASK ACTIVITY

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W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT



## MEASUREMENT AND TEST EQUIPMENT

| ACTIVITY | ID NUMBER | DATE USED | DESCRIPTION |
|---|---|---|---|
| 01 | NONE | N/A | |

RECURRING TASK ACTIVITY

W/O NBR : R2099351 01
A/R NBR : A2161370
W/O STATUS : HISTRY 22JUN07
ACT STATUS : HISTRY 22JUN07
TYPE : ACT

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RECURRING TASK WORK ORDER

NUMBER : R2104033 ACT
PRIORITY : 5
STATUS : HISTRY 29AUG07
NBR OF ACTS: 01
LAST UPDATE: 29AUG07
PRINT DATE : 10SEP07

APPLICANT'S EXHIBIT 54

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 03

AR NUMBER : A2168200 RESPONSIBLE ORG : OPO

APPROVED BY : RITCHIE AR TYPE/SUBTYPE : RT ACT

RESP FOREMAN : SSV5 OC OPS SHIFT SUPV MUC : C

MAINT UNIT FEG : OC 1 187 000 ATTACHMENTS: N

M/U COMPONENT ID : OC 1 187 F MISC 187

MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

EQUIP REQD MODES : A QA CLASS : Q

PROCEDURE NUMBER : EQ : Y

COMPONENT UPDATE : N SAFE S/D : * ASME SECTION XI : Y

BOM/PART UPDATE : N POST MAINT TEST : N

MOD NUMBER : REPEAT/ PEP NBR : N

NEXT DUE DATE : 21AUG07 TASK FREQUENCY : 0091
TECH SPEC DATE : 12SEP07 UNIT : D

=============================== ACCOUNTING DATA ============================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05310

OPERATING UNIT: 83

=============================================================================

RECURRING TASK WORK ORDER

NUMBER : R2104033 ACT
PRIORITY : 5
STATUS : HISTRY 29AUG07
NBR OF ACTS: 01
LAST UPDATE: 29AUG07
PRINT DATE : 10SEP07

W/O DESC INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN PAGE: 04

==========================WORK ORDER COMPONENTS==========================

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI OOO ASME SECTION XI: Y

QA CLASS : Q EQ : Y

==========================COMPLETION VERIFICATION==========================

PKG ASSMBLED : OTHER :

RESP FOREMAN : SISAK, JOSHUA V REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: N COMPLETE DATE: 28AUG07

==========================HISTORY VERIFICATION==========================

COMPNT UPDATE : N BLIP NBR BOX: 0000
BILL OF MATLS : N FILE LOCATION:
REPEAT REQD : A/R NBR :
COMPLETED BY : SISAK, JOSHUA V COMPLETE DATE: 28AUG07
CLOSED BY : STRAKA, GINAMARIE HISTORY DATE : 29AUG07
CAUSE CODE : CF REPAIR CODE : NF

==========================COMPLETION REMARKS==========================

REPEAT MAINT: N PEP NBR: ========

**WORK PERFORMED:**

A01 TORUS INSPECTION COMPLETED SAT. NO WATER WAS NOTED IN 5 BOTTLES. 28AUG07
JVS3 28AUG07

RECURRING TASK ACTIVITY

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W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT

RWP ACCESS CODE: OC-1-07-00052 PAGE: 01

==============================DESCRIPTION==============================

W/O DESCRIPTION : INSPECT POLY BOTTLES FOR PRESENCE OF WATER IN
ACT DESCRIPTION : INSPECT POLY BOTTLES IN TORUS ROOM
PERFORMING ORG : OPO RECURRING TASK NBR: PM18705M PRI: 5
COMPONENT ID : OC 1 187 F MISC 187
EQUIPMENT LOCATION: MULTI 000
CLR NUMBER : ______ QA CLASS: Q EQ: Y
WO RESP ORG : OPO FEG : OC 1 187 000
DATE/SHIFT : 28AUG07 X
FOREMAN : OC OPS SHIFT SUPV CHARGING WORK CENTER: 05310
SSV AUTH : DFR1 ______ DATE : 27AUG07
ORG-INSP/HOLD : ______

ACT TYPE : C SUPPORT DATES: N/A N/A
PREPARED BY : RITCHIE DATE : 25MAY06
HOLDS : MODE N PARTS N CHEM + RAD ___ CLR ___ PLAN ___ SCH ___

==================SAFETY/PLANT IMPACT CONSIDERATIONS==================

BARRIER PERMIT RQD: N CHEMICAL HAZARD : N CSP REQ : N
FIRE PROTECTION : N SECURITY : N FSI REQ : N
HAZARD BARRIER : N / ______

============================CHEM AND RAD DATA============================

SYSTEM BREACH : N INSULATION REQUIRED: N
HWP REQ : N SCAFFOLDING REQD : N TECH SPEC: N
MULTIPLE WORK LOC : ___ MAP NBR: ______
HP REQD : N NO HP ASSISTANCE REQUIRED

============================SCHEDULING DATA============================

PREMIS ID : 0735 187 SCHED ID/WIN : 0735 187
START DATE : 28AUG07 EST DUR (HRS) : 3 POST MAINT TEST: ___
CLEARANCE REQD : N DUE DATE : 21AUG07 TECH SPEC: 12SEP07
DOSE ESTIMATE : 0002 mR

============================INITIAL REVIEWS============================

ASME/ISI REVIEW : N/A ASME XI R&R: ___ DATE: 23MAY07
QC PLAN REVIEW : SULLIVAN, M. NQCR ___ - ___ DATE: 23MAY07
APPROVED BY : VOISHNIS, G DATE: ______

======================================================================

PRINT NAME AND WRITE INITIALS OF ALL PERSONNEL WHO INITIALED THIS ACTIVITY

RECURRING TASK ACTIVITY

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    **      **********   **      **
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W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT



==========================ACTIVITY PROCEDURE LIST==============================

======================== RAD PROTECTION REQUIREMENTS ========================

ALARMING DOSIMETER: Y

ED SETPOINT: 0032 MREM or 0300 MREM/HR

HP COVERAGE: INTERMITTENT

RWP ACCESS CODE: OC-1-07-00052

========================= HP SPECIAL INSTRUCTIONS ==========================

* OPERATIONS.
* THIS RWP IS NOT VALID FOR VHRA,DW OR CB/SJAE RM AT POWER.
* KNOWLEDGE OF RAD CONDITIONS REQ'D PRIOR TO ENTRY TO RCA W/OUT RPT ESCORT.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* OPERATORS SHALL NOTIFY RP BEFORE PERFORMING ANY ACTIVITES THAT COULD RESULT IN CHANGING AREA DOSE RATES. EXAMPLES INCLUDE DRAINING SYSTEM OR COMPONENT THAT CONTAINS RADIOACTIVITY (TANKS, FILTERS, PIPING, ETC.)

OPEX:

- CLEARANCE AND TAGGING ACTIVITIES-FAILURE TO ADHERE TO OR INADEQUATE TAGOUT INSTRUCTIONS HAVE CONTRIBUTED TO LOSSES IN GENERATION AND HAZARDOUS WORKING CONDITIONS.OE #S:OE20012,OE20535,OE19214.

RECURRING TASK ACTIVITY

W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT



====================== ACTIVITY FOLLOWER DESCRIPTION ======================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|

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NOTE

STEPS ANNOTATED WITH "CM-1" ARE REGULATORY COMMITTMENTS THEY CAN NOT BE CHANGED OR SKIPPED WITHOUT PERMISSION FROM REGULATORY ASSURANCE

************************************************

1. PURPOSE:

   A. THE PURPOSE OF THIS ACTIVITY IS INSPECT THE POLY BOTTLES IN THE TORUS ROOM FOR THE PRESENCE OF WATER.

2. CLEARANCE REQUIREMENTS:

   A. NONE

3. OPS IMPACT STATEMENT:

   A. NONE.

4. PRECAUTIONS

   A. USE EXTREME CAUTION WHEN WORKING ON OR NEAR ROTATING EQUIPMENT. REFERENCE THE MID-ATLANTIC ROG SAFETY AND HEALTH GUIDE AND PROCEDURE EN-OC-301 FOR

==================== ACTIVITY FOLLOWER DESCRIPTION ====================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | CAUTIONS AND PRECAUTIONS ASSOCIATED WITH | | |
| | THIS WORK. | | |
| | B. BE SURE A PRE-JOB BRIEF IS PERFORMED AND | | |
| | ALL CAUTIONS AND PRECAUTIONS ASSOCIATED | | |
| | WITH THIS ACTIVITY ARE PROPERLY ADDRESSED | | |
| | AND ANY AND ALL CONCERNS AND QUESTIONS | | |
| | HAVE BEEN RESOLVED BEFORE STARTING WORK. | | |
| | . | | |
| | 5. SUPPORT INFORMATION | | |
| | . A. NONE | | |
| | . | | |
| | 6. JOB SCOPE | | |
| | A. INSPECTION OF POLY BOTTLES INSIDE THE TORUS | | |
| | ROOM. THERE ARE 5 POLY BOTTLES LOCATED | | |
| | AROUND THE OUTER PERIMETER OF THE TORUS. | | |
| | THE INSPECTION SHALL INCLUDE CHECKING FOR | | |
| | THE PRESENCE OF WATER IN THE BOTTLES. | | |
| | DOCUMENT IN THE CREM IF WATER IS PRESENT, | | |
| | AND IF SO, WHAT IS THE LEVEL IN THE BOTTLE | | |
| | AND THE LOCATION OF THE BOTTLE (BY BAY | | |
| | NUMBER). | | |
| | . | | |

RECURRING TASK ACTIVITY

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W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT



====================== ACTIVITY FOLLOWER DESCRIPTION ======================

| STEP NBR | DESCRIPTION | INITIAL/DATE COMPLT | INSP |
|---|---|---|---|
| | B. IF WATER IS FOUND IN ANY OF THE POLY | | |
| | BOTTLES,PERFORM THE FOLLOWING: | | |
| | - INVESTIGATE AND FIND THE SOURCE. | | |
| | - REQUEST A CHEMISTRY SAMPLE. DO NOT | | |
| | EMPTY ANY BOTTLES UNTIL A SAMPLE | | |
| | HAS BEEN TAKEN. | | |
| | - ISSUE IR | | |
| | - IDENTIFY BY BAY NUMBER WHICH BOTTLES | | |
| | HAVE WATER AND INDICATE THE LEVEL IN | | |
| | THE BOTTLE. | | |
| | C. EMPTY BOTTLE AS DIRECTED BY ENGINEERING | | |

RECURRING TASK ACTIVITY

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W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT



=============================SUMMARY COMMENTS:==============================

CAUSE CODE: __ __ __ REPAIR CODE: __ __ __

ADDITIONAL PAGES ATTACHED ? ____ ETT REMOVED ? ____

======================MEASUREMENT AND TEST EQUIPMENT========================

| ID NUMBER | DATE USED | DESCRIPTION | ADDITIONAL PAGES ATTACHED ? ___ |
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============================FINAL REVIEWS==================================

MAINT ______________________ DATE : ________________

QC ______________________ DATE : ________________

OTHER ______________________ DATE : ________________

RECURRING TASK ACTIVITY

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W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT



## MEASUREMENT AND TEST EQUIPMENT

| ACTIVITY | ID NUMBER | DATE USED | DESCRIPTION |
|---|---|---|---|
| 01 | NONE | N/A | |

RECURRING TASK ACTIVITY

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W/O NBR : R2104033 01
A/R NBR : A2168200
W/O STATUS : HISTRY 29AUG07
ACT STATUS : HISTRY 29AUG07
TYPE : ACT

RECURRING TASK WORK ORDER

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NUMBER : R2088495 ACT
PRIORITY : 5
STATUS : ASIGND 24OCT06
NBR OF ACTS: 05
LAST UPDATE: 05NOV06
PRINT DATE : 05NOV06

**APPLICANT'S EXHIBIT 55**

W/O DESC LEAKAGE MONITORING TORUS, SANDBEDS & RX DRAIN PAGE: 01

AR NUMBER : A2145130
RESPONSIBLE ORG : OEPB
APPROVED BY : YARNES,R
AR TYPE/SUBTYPE : RT ACT
RESP FOREMAN : OEPB OC PLANT ENG BAL PLT
MUC : C
MAINT UNIT FEG : OC 1 187 000
ATTACHMENTS: N
M/U COMPONENT ID : OC 1 187 F MISC 187
MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)
EQUIP REQD MODES : 5
QA CLASS : Q
PROCEDURE NUMBER :
EQ : Y
COMPONENT UPDATE : N SAFE S/D : * ASME SECTION XI : Y
BOM/PART UPDATE : N
POST MAINT TEST : Y
MOD NUMBER :
REPEAT/ PEP NBR : N
NEXT DUE DATE : 16OCT05
TASK FREQUENCY : 0001
TECH SPEC DATE :
UNIT : R

=============================== ACCOUNTING DATA ===============================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05330

OPERATING UNIT: 83

===============================================================================

OCLR00029083

RECURRING TASK WORK ORDER

NUMBER : R2088495 ACT
PRIORITY : 5
STATUS : ASIGND 24OCT06
NBR OF ACTS: 05
LAST UPDATE: 05NOV06
PRINT DATE : 05NOV06

APPLICANT'S EXHIBIT 55

W/O DESC LEAKAGE MONITORING TORUS, SANDBEDS & RX DRAIN PAGE: 02

===========================WORK ORDER COMPONENTS===========================

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI QQQ ASME SECTION XI: Y

QA CLASS : Q EQ : Y

===========================COMPLETION VERIFICATION===========================

PKG ASSMBLED : OTHER :

RESP FOREMAN : REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: COMPLETE DATE:

===========================HISTORY VERIFICATION===========================

COMPNT UPDATE : RMS DOC NBR :

BILL OF MATLS : RMS FILM NBR :

REPEAT REQD : A/R NBR:

COMPLETE BY :

HISTORY DATE :

===========================COMPLETION REMARKS===========================

REPEAT MAINT: N PEP NBR: ========

**AS FOUND CONDITION:**

ACT 01: FIRST WALKDOWN COMPLETED WITH RX CAVITY FLOODED BY F.STULB 19OCT06
NO WATER WAS DETECTED IN THE POLY BOTTLES. FULL WALKDOWN 19OCT06
REPORT BEING GATHERED IN THE LR TEAM ROOM. 19OCT06
. 19OCT06
POLY BOTTLES WERE WALKED DOWN BY PETE TAMBURRO OR BOB BARBIERI 19OCT06
ON 10/16, 10/17, 10/18, AND 10/19. NO WATER WAS FOUND IN ALL 19OCT06
FIVE BOTTLE. NO WATER WAS FOUND ON TORUS ROOM FLOOR. SECTION 19OCT06
6.1 OF WORK ORDER ENTERED BY PETE TAMBURRO 19OCT06
. 19OCT06
TROUGH DRAIN WAS WALKED DOWN BY PETE TAMBURRO ON 10/16, 10/17, 19OCT06
AND 10/18 PRIOR TO REACTOR CAVITY FLOOD UP. NO WATER WAS OBSERVED 19OCT06
FLOWING TO THE HUB DRAIN. ENTERED BY PTE TAMBURRO SEC 6.2 19OCT06
. 19OCT06
ON 10/19 AT 8:00 AM APPROXIMATELY 12 HOURS AFTER REACTOR 19OCT06
CAVITY FLOOD UP THE TROUGH DRAIN LINE DOWNSTREAM OF V-18-131 19OCT06
WAS OBSERVED TO HAVE A SMALL CONITINOUS STREAM OF WATER ENTERING 19OCT06
THE HUB DRAIN. THE SIZE OF THE STEAM WAS APROXIMATELY PENCIL 19OCT06
SIZE AND ESTIMATED TO BY ABOUT 1 GPM. SEC 6.2 19OCT06

RECURRING TASK WORK ORDER

NUMBER : R2088495 ACT
PRIORITY : 5
STATUS : ASIGND 24OCT06
NBR OF ACTS: 05
LAST UPDATE: 05NOV06
PRINT DATE : 05NOV06

APPLICANT'S EXHIBIT 55

W/O DESC LEAKAGE MONITORING TORUS, SANDBEDS & RX DRAIN PAGE: 03

==========================COMPLETION REMARKS==================================

REPEAT MAINT: N PEP NBR: ________

| | |
|---|---|
| ON 10/20 AT 1000 | 20OCT06 |
| THE TROUGH DRAIN LINE DOWNSTREAM OF V-18-131 | 20OCT06 |
| WAS OBSERVED BY BOB BARBIERI | 20OCT06 |
| TO HAVE A SMALL CONITINOUS STREAM OF WATER ENTERING | 20OCT06 |
| THE HUB DRAIN. THE SIZE OF THE STEAM WAS APROXIMATELY PENCIL | 20OCT06 |
| SIZE AND ESTIMATED TO BY ABOUT 1 GPM. SEC 6.2 | 20OCT06 |
| . | 20OCT06 |
| . | 20OCT06 |
| ON 10/20 AT 10:00 THE | 20OCT06 |
| POLY BOTTLES WERE WALKED DOWN BY BOB BARBIERI AND WERE | 20OCT06 |
| NO WATER IN ALL 5 BOTTLES. SEC 6.1 | 20OCT06 |
| . | 20OCT06 |
| . | 20OCT06 |
| . | 21OCT06 |
| ON 10/21 AT 13:30 | 21OCT06 |
| THE TROUGH DRAIN LINE DOWNSTREAM OF V-18-131 | 21OCT06 |
| WAS OBSERVED BY PETE TAMBURRO | 21OCT06 |
| TO HAVE A SMALL CONITINOUS STREAM OF WATER ENTERING | 21OCT06 |
| THE HUB DRAIN. THE SIZE OF THE STEAM WAS APROXIMATELY PENCIL | 21OCT06 |
| SIZE AND ESTIMATED TO BY ABOUT 1 GPM. SEC 6.2 | 21OCT06 |
| . | 21OCT06 |
| . | 21OCT06 |
| ON 10/21 AT 13:30 THE | 21OCT06 |
| POLY BOTTLES WERE WALKED DOWN BY PETE TAMBURRO AND THERE WAS | 21OCT06 |
| NO WATER IN ALL 5 BOTTLES. SEC 6.1 | 21OCT06 |
| . | 22OCT06 |
| 10/22/06 15:00 - | 22OCT06 |
| PERFORMED WALK DOWN IN TORUS ROOM AND INSPECTED ALL 5 POLY BOTTLES. | 22OCT06 |
| ALL WERE DRY, AS WERE THE HOSES. LOOKED UNDER TORUS FOR SIGNS OF | 22OCT06 |
| WATER; NONE WAS PRESENT | 22OCT06 |
| . | 22OCT06 |
| ALSO INSPECTED HUB DRAIN ON 75'. THERE WAS A CONTINUOUS FLOW | 22OCT06 |
| CATEGORIZED AS A MODERATE SIZE PENCIL STREAM. THIS WAS CONSISTENT | 22OCT06 |
| WITH PREVIOUS INSPECTIONS. | 22OCT06 |
| R. BARBIERI | 22OCT06 |
| . | 23OCT06 |
| 10/23/06 13:30 - | 23OCT06 |
| PERFORMED WALK DOWN IN TORUS ROOM AND INSPECTED ALL 5 POLY BOTTLES. | 23OCT06 |
| ALL WERE DRY, AS WERE THE HOSES. LOOKED UNDER TORUS FOR SIGNS OF | 23OCT06 |
| WATER; NONE WAS PRESENT | 23OCT06 |
| . | 23OCT06 |
| ALSO INSPECTED HUB DRAIN ON 75'. THERE WAS A CONTINUOUS FLOW | 23OCT06 |
| CATEGORIZED AS A MODERATE SIZE PENCIL STREAM. THIS WAS CONSISTENT | 23OCT06 |
| WITH PREVIOUS INSPECTIONS. | 23OCT06 |
| PETE TAMBURRO | 23OCT06 |
| . | 24OCT06 |
| 10/24/06, 10:30 - | 24OCT06 |
| PERFORMED WALK DOWN IN TORUS ROOM. INSPECTED ALL 5 POLY BOTTLES AND | 24OCT06 |
| CONNECTING TUBING. NO WATER OBSERVED. ALSO INSPECTED UNDER TORUS IN | 24OCT06 |
| ALL BAYS. NO WATER PRESENT. | 24OCT06 |
| . | 24OCT06 |

RECURRING TASK WORK ORDER

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NUMBER : R2088495 ACT
PRIORITY : 5
STATUS : ASIGND 24OCT06
NBR OF ACTS: 05
LAST UPDATE: 05NOV06
PRINT DATE : 05NOV06

APPLICANT'S EXHIBIT 55

W/O DESC LEAKAGE MONITORING TORUS, SANDBEDS & RX DRAIN PAGE: 04

==========================COMPLETION REMARKS================================

REPEAT MAINT: N PEP NBR: ________ ========

| | |
|---|---|
| PERFORMED INSPECTION OF REACTOR CAVITY TROUGH DRAIN ON 75'. LEAKAGE | 24OCT06 |
| IS CONSISTENT WITH PAST INSPECTIONS. LEAKAGE IS STILL A MODERATE | 24OCT06 |
| PENCIL STREAM AND IS STEADY. | 24OCT06 |
| R. BARBIERI | 24OCT06 |
| . | 24OCT06 |
| 10/25/06 20:30 | 25OCT06 |
| PERFORMED INSPECTION OF REACTOR CAVITY TROUGH DRAIN ON 75' ELEVATION | 25OCT06 |
| THERE WAS A PENCIL STREAM - NO CHANGE IN FLOW. PERFORMED WALK DOWN | 25OCT06 |
| OF ALL 5 POLY BOTTLES IN TORUS ROOM. THERE WAS NO WATER PRESENT IN | 25OCT06 |
| ANY OF THE BOTTLES. WATER ON THE FLOOR TO THE LEFT OF NORTHEAST | 25OCT06 |
| CORNER ROOM DOOR (BAY 17). WATER WAS NOTED DRIPPING FROM ABOVE AT | 25OCT06 |
| ABOUT 60+ DROPS PER MINUTE AND IS ALSO RUNNING DOWN THE SIDE OF THE | 25OCT06 |
| TORUS AND COLLECTING UNDERNEATH. | 25OCT06 |
| F. STULB | 25OCT06 |
| . | 25OCT06 |
| 10/26/06 14:30 | 26OCT06 |
| INSPECTED TORUS ROOM FOR SIGNS OF WATER. ALL 5 POLY BOTTLES WERE | 26OCT06 |
| EMPTY. NOTED PUDDLE ON FLOOR NEAR DRYWELL WALL IN BAY 11 (THE POLY- | 26OCT06 |
| BOTTLE IN BAY 11 WAS EMPTY). DID NOT APPEAR THAT DRYWELL WAS WET, | 26OCT06 |
| BUT NEED ADDITIONAL INSPECTION TO DETERMINE SOURCE. NOTE THAT 1-6 | 26OCT06 |
| SUMP WAS TAGGED OUT AND WAS OVERFLOWING. THIS COULD BE THE CAUSE OF | 26OCT06 |
| WATER IN BAY 11. IR SUBMITTED. | 26OCT06 |
| . | 26OCT06 |
| INSPECTED TROUGH DRAIN. NO CHANGE FROM PREVIOUS INSPECTIONS. PENCIL | 26OCT06 |
| STREAM NOTED. | 26OCT06 |
| R. BARBIERI | 26OCT06 |
| . | 27OCT06 |
| 10/27/06 14:30 | 27OCT06 |
| INSPECTED TROUGH DRAIN. NO CHANGE FROM PREVIOUS. PENCIL STREAM. | 27OCT06 |
| INSPECTED POLY BOTTLES. NO WATER IN ANY BOTTLES. FOUND PUDDLE NEAR | 27OCT06 |
| DRYWELL WALL IN BAY 11, AND DETERMINED THAT DRYWELL WALL WAS WET. | 27OCT06 |
| COULD NOT FIND SOURCE. NEED TO GO ON TOP OF TORUS. | 27OCT06 |
| REPORTED TO LICENSE RENEWAL TEAM. | 27OCT06 |
| ISSUED IR 549432-02 TO INSPECT SAND BED IN BAY 11. | 27OCT06 |
| R. BARBIERI | 27OCT06 |
| 10/28/06 14:00 | 28OCT06 |
| INSPECTED TROUGH DRAIN AND NO CHANGE FROM PREVIOUS INSPECTIONS. | 28OCT06 |
| THE LEAKAGE WAS PENCIL STREAM SIZE. | 28OCT06 |
| INSPECTED TORUS ROOM AND ALL 5 BOTTLES WERE EMPTY. NO WATER ON FLOOR | 28OCT06 |
| EXCEPT IN BAY 11 AS NOTED PREVIOUSLY. | 28OCT06 |
| DUE TO THIS WATER IN BAY 11, PERFORMED WALKDOWN ON TOP OF TORUS. | 28OCT06 |
| NOTED WATER LEAKING FROM AROUND VENT PIPE. ABOUT 1 DROP EVERY 10 | 28OCT06 |
| SECONDS. PETE TAMBURRO ENTERED TUNNEL AND INSPECTED INSIDE OF SAND | 28OCT06 |
| BED. THERE WAS NO WATER PRESENT IN SAND BED AREA OR IN THE TUNNEL. | 28OCT06 |
| R. BARBIERI | 28OCT06 |
| . | 28OCT06 |
| 10/29/06 13:10 | 29OCT06 |
| INSPECTED TROUGH DRAIN AND NO CHANGE FROM PREVIOUS INSPECTIONS. | 29OCT06 |
| THE LEAKAGE WAS PENCIL STREAM SIZE. | 29OCT06 |
| INSPECTED TORUS ROOM AND ALL 5 BOTTLES WERE EMPTY. NO WATER ON FLOOR | 29OCT06 |
| EXCEPT IN BAY 11 AS NOTED PREVIOUSLY. PETE TAMBURRO | 29OCT06 |

RECURRING TASK WORK ORDER

NUMBER : R2088495 ACT
PRIORITY : 5
STATUS : ASIGND 24OCT06
NBR OF ACTS: 05
LAST UPDATE: 05NOV06
PRINT DATE : 05NOV06

APPLICANT'S EXHIBIT 55

W/O DESC LEAKAGE MONITORING TORUS, SANDBEDS & RX DRAIN PAGE: 05

=========================COMPLETION REMARKS=========================

REPEAT MAINT: N PEP NBR: ________ ========

. 30OCT06
10/30/06 21:30 30OCT06
PERFORMED INSPECTION OF REACTOR CAVITY TROUGH DRAIN ON 75' ELEVATION 30OCT06
THERE WAS A PENCIL STREAM - NO CHANGE IN FLOW. PERFORMED WALK DOWN 30OCT06
OF ALL 5 POLY BOTTLES IN TORUS ROOM. THERE WAS NO WATER PRESENT IN 30OCT06
ANY OF THE BOTTLES. WATER ON THE FLOOR AND UNDER TORUS 1 BAY TO THE 30OCT06
LEFT OF NORTHEAST CORNER ROOM DOOR. WATER ON FLOOR 2-3 BAYS RIGHT 30OCT06
OF NORTHEAST CORNER ROOM DOOR. THERE WAS WATER ON THE FLOOR UNDER 30OCT06
THE TORUS NEAR BAY 11 BOTTLE AS NOTED IN PREVIOUS INSPECTIONS. 30OCT06
FRANK STULB 30OCT06
. 31OCT06
10/31/06 13:30 31OCT06
INSPECTED TROUGH DRAIN AND NO CHANGE FROM PREVIOUS INSPECTIONS. A 31OCT06
PENCIL STREAM WAS NOTED. 31OCT06
INSPECTED POLY BOTTLES IN TORUS ROOM. ALL WERE EMPTY. NO WATER FOUND 31OCT06
EXCEPT AS PREVIOUSLY NOTED. 31OCT06
R. BARBIERI 31OCT06
. 31OCT06
11/01/06 17:30 01NOV06
INSPECTED TROUGH DRAIN AND NO CHANGE FROM PREVIOUS INSPECTIONS. A 01NOV06
PENCIL STREAM WAS NOTED. 01NOV06
INSPECTED POLY BOTTLES IN TORUS ROOM. ALL WERE EMPTY. NO WATER FOUND 01NOV06
EXCEPT AS PREVIOUSLY NOTED. 01NOV06
PETE TAMBURRO 11/1/06 01NOV06
. 01NOV06
11/03/06 00:20 MIKE HAND 03NOV06
INSPECTED TROUGH DRAIN AND NO CHANGE FROM PREVIOUS INSPECTIONS. A 03NOV06
INSPECTED POLY BOTTLES IN TORUS ROOM. ALL WERE EMPTY. NO WATER FOUND 03NOV06
ENTERED BY PETE TAMBURRO ON 11/3/06 A 7:14 03NOV06
. 03NOV06
11/3/06 15:30 03NOV06
ADDITIONAL INSPECTIONS PERFORMED DURING FLOOD UP WERE AS FOLLOWS: 03NOV06
INSPECTED CEILINGS ON 75' FOR SIGNS OF WATER ON A DAILY BASIS. NO 03NOV06
WATER WAS FOUND. ALSO INSPECTED PIPE PENETRATIONS INTO THE POOLS AND 03NOV06
CAVITY, AND NO WATER WAS FOUND. 03NOV06
A. HERTZ INSPECTED ELECTRICAL PENETRATIIONS AND FOUND NO 03NOV06
SIGNS OF WATER. 03NOV06
THE 2 EQUIPMENT POOL DRAINS WERE ALSO INSPECTED ON A DAILY BASIS. NO 03NOV06
WATER WAS OBSERVED FROM THESE DRAINS. 03NOV06
R. BARBIERI 03NOV06
. 03NOV06
ON 11/3/06 AT 16:30 THE TROUGH DRIAN WAS INSPECTED AND NO WATER 03NOV06
WAS OBSERVED FLOWING FROM THE DRAIN. PLEASE NOTE REACTOR 03NOV06
CAVITY DRAIN DOWN WAS COMPLETED A 1 AM ON 11/3/06 03NOV06
PETE TAMBURRO 03NOV06
. 03NOV06
11/03/06 20:30 03NOV06
PERFORMED WALK DOWN OF ALL 5 POLY BOTTLES IN TORUS ROOM. THERE WAS 03NOV06
NO WATER PRESENT IN ANY OF THE BOTTLES. 03NOV06
FRANK STULB 03NOV06
. 04NOV06

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RECURRING TASK WORK ORDER                **        **********    **     **
                                        ****       **********    ****  ****
NUMBER       : R2088495   ACT            **        **      **    ** **** **
PRIORITY     : 5                         **        **********    **  **  **
STATUS       : ASIGND   24OCT06          **        **********    **      **
NBR OF ACTS: 05                          **        **            **      **
LAST UPDATE: 05NOV06                     **        **            **      **
PRINT DATE : 05NOV06                   ******      **            **      **
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APPLICANT'S EXHIBIT 55

**W/O DESC** LEAKAGE MONITORING TORUS, SANDBEDS & RX DRAIN PAGE: 06

===========================COMPLETION REMARKS===========================

REPEAT MAINT: N PEP NBR: ________ ========

REFERENCE ACTIVITY 03 BOROSCOPE OF THE 5 SANDBED DRAINS WERE 04NOV06
PERFORMED ON 10/210/06. THE INSPECTION FOUND THAT THE DRAIN 04NOV06
IN BAY 7 WAS BLOCKED. IR 547236 WAS ISSUED. 04NOV06
11/04/04 23:30 05NOV06
PERFORMED WALK DOWN OF ALL 5 POLY BOTTLES IN TORUS ROOM. THERE WAS 05NOV06
NO WATER PRESENT IN ANY OF THE BOTTLES. THIS IS THE LAST INSPECTION 05NOV06
OF THE POLY BOTTLES FOR 1R21. THE PM FOR THE QUARTERLY INSPECTIONS 05NOV06
DURING THE OPERATING CYCLE SHOULD BE INITIATED. 05NOV06
FRANK STULB 05NOV06

**AS LEFT CONDITION:**

A03: REVIEW OF VIDEO AFTER DRAIN WAS CLEARED WAS SATISFACTORY. ALL 30OCT06
DRAINS ARE NOW CLEAR. DTB0 30OCT06
A03 AND A04: VERIFICATION OF THE SAND BED DRAINS AS BEING CLEAR WAS 31OCT06
PERFORMED BY PETER TAMBURRO AFTER THE COMPLETION OF THE CLEANING 31OCT06
REQUIRED BY IR 547236 ON BAYS 7 AND 11. ALL SAND BED DRAINS ARE NOW 31OCT06
VERIFIED CLEAR BASE ON THE REVIEW OF THE VIDEO BY PETER TAMBURRO 31OCT06
THIS WAS VERIFIED BY DAN BARNES AND DOCUMENTED HERE BY TOM QUINTENZ 31OCT06
TEQ0 31OCT06

**WORK PERFORMED:**

A02 SUPPORT NOT REQUIRED. DTB0 04NOV06

RECURRING TASK WORK ORDER

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******    **          **      **
```

NUMBER : R2088493 ACT
PRIORITY : 5
STATUS : HISTRY 29APR07
NBR OF ACTS: 06
LAST UPDATE: 29APR07
PRINT DATE : 09AUG07

APPLICANT'S EXHIBIT 56

W/O DESC CAMERA INSPECTION OF REACTOR CAVITY DRAIN LINE PAGE: 01

AR NUMBER : A2145128 RESPONSIBLE ORG : OMM3
APPROVED BY : DOLL, RICK AR TYPE/SUBTYPE : RT ACT
RESP FOREMAN : OMM3 MAINTENANCE TEAM 3 MUC : C
MAINT UNIT FEG : OC 1 187 000 ATTACHMENTS: N
M/U COMPONENT ID : OC 1 187 F MISC 187
MAINT UNIT DESCR : DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)
EQUIP REQD MODES : 5 QA CLASS : Q
PROCEDURE NUMBER : EQ : Y
COMPONENT UPDATE : N SAFE S/D : * ASME SECTION XI : Y
BOM/PART UPDATE : N POST MAINT TEST : Y
MOD NUMBER : REPEAT/ PEP NBR : N
NEXT DUE DATE : 17OCT06 TASK FREQUENCY : 0001
TECH SPEC DATE : UNIT : R

============================== ACCOUNTING DATA ==============================

BUSINESS UNIT : 10105 PROJECT:

CUSTOMER: SUB ACCT: 517010 PRODUCT: DEPARTMENT: 05322

OPERATING UNIT: 83

===========================================================================

RECURRING TASK WORK ORDER

NUMBER : R2088493 ACT
PRIORITY : 5
STATUS : HISTRY 29APR07
NBR OF ACTS: 06
LAST UPDATE: 29APR07
PRINT DATE : 09AUG07

W/O DESC CAMERA INSPECTION OF REACTOR CAVITY DRAIN LINE PAGE: 02

==========================WORK ORDER COMPONENTS==========================

COMPONENT ID : OC 1 187 F MISC 187
DRYWELL AND TORUS (SEE NR01 & TORUS VESSEL)

CHEM/RAD MAP :

LOCATION : MULTI QQQ ASME SECTION XI: Y

QA CLASS : Q EQ : Y

==========================COMPLETION VERIFICATION==========================

PKG ASSMBLED : JCC6 COLUCCI, JOHN C OTHER :

RESP FOREMAN : COLUCCI, JOHN C REPEAT REQD :

SSV VERIF : N

ASME - ISI BY: N COMPLETE DATE: 06NOV06

==========================HISTORY VERIFICATION==========================

COMPNT UPDATE : N BLIP NBR BOX: 0000
BILL OF MATLS : N FILE LOCATION:
REPEAT REQD : A/R NBR :
COMPLETED BY : COLUCCI, JOHN C COMPLETE DATE: 06NOV06
CLOSED BY : JOHNSTON, IRENE L HISTORY DATE : 29APR07
CAUSE CODE : CA REPAIR CODE : NF

==========================COMPLETION REMARKS==========================

REPEAT MAINT: N PEP NBR: ========

**AS FOUND CONDITION:**

ACT 01 ZERO BLOCKAGE FOUND. PETE TAMBURRO HAS VIDEO OF BOROSCOPE. 06NOV06
DRR0 06NOV06
. 06NOV06
ACT 02 ZERO BLOCKAGE FOUND. PETE TAMBURRO HAS VIDEO OF BOROSCOPE. 06NOV06
DRR0 06NOV06
. 06NOV06
I HAVE REVIEWED BOTH VIDEOS AND FOUND NO BLOCKAGE. PETE TAMBURRO 10APR07

**WORK PERFORMED:**

ACT 03: ERECTED SCAFFOLD C6-1510 AS DIRECTED. ELECTRONIC SIGNOFFS 04OCT06
PERFORMED BY A.M.STANFORD FOR G.LANE. 04OCT06
ACT 02: INSPECTIONS PERFORMED IAW WORK STEPS. RESULTS SAT. PETE 24OCT06
TAMBURRO HAS VIDEO. DRR0 24OCT06
ACT 01: INSPECTIONS PERFORMED IAW WORK STEPS. RESULTS SAT. PETE 06NOV06
TAMBURRO HAS VIDEO. DRR0 06NOV06
ACT.04 REMOVED SCAFFOLD C6-1510 AS DIRECTED. GAL3 17NOV06
. 23APR07
A05: ACTIVITY HAS BEEN COMPLETED. SEE AS FOUND SECTION FOR PETE'S 23APR07
COMMENTS. FGA0 23APR07
A06: NO WORK PERFORMED 25APR07

**SUSPECTED CAUSE OF FAILURE:**

NO FAILURE THESE TASK 25APR07

RECURRING TASK ACTIVITY

W/O NBR : R2088493 01
A/R NBR : A2145128
W/O STATUS : HISTRY 29APR07
ACT STATUS : HISTRY 29APR07
TYPE : ACT

PAGE: 01

==============================DESCRIPTION==============================

W/O DESCRIPTION : CAMERA INSPECTION OF REACTOR CAVITY DRAIN LINE
ACT DESCRIPTION : PRE-OUTAGE INSP. OF RX CAVITY DRAIN LINE.
PERFORMING ORG : OMM3 RECURRING TASK NBR: PM18703M PRI: 5
COMPONENT ID : OC 1 187 F MISC 187
EQUIPMENT LOCATION: MULTI 000
CLR NUMBER : 6501333 QA CLASS: Q EQ: Y
WO RESP ORG : OMM3 FEG : OC 1 187 000
DATE/SHIFT : 13OCT06 X
FOREMAN : MAINTENANCE TEAM 3 CHARGING WORK CENTER: 05322
SSV AUTH : DATE : N/A
ORG-INSP/HOLD :

ACT TYPE : C SUPPORT DATES: N/A N/A
PREPARED BY : DOLL, RICK DATE : 09MAY06
HOLDS : MODE N PARTS N CHEM + RAD ___ CLR ___ PLAN ___ SCH ___

==================SAFETY/PLANT IMPACT CONSIDERATIONS==================

BARRIER PERMIT RQD: ___ CHEMICAL HAZARD : N CSP REQ : N
FIRE PROTECTION : N SECURITY : N FSI REQ : N
HAZARD BARRIER : N /

===========================CHEM AND RAD DATA===========================

SYSTEM BREACH : Y INSULATION REQUIRED: N
HWP REQ : N SCAFFOLDING REQD : Y TECH SPEC: N
MULTIPLE WORK LOC : MAP NBR:
HP REQD : T HP TECHNICIAN SUPPORT REQUIRED

===========================SCHEDULING DATA===========================

PREMIS ID : 1P41 187 SCHED ID/WIN : 1P41 187
START DATE : 09OCT06 EST DUR (HRS) : 1 POST MAINT TEST:
CLEARANCE REQD : Y DUE DATE : 17OCT06 TECH SPEC: N/A
DOSE ESTIMATE : 0016 mR

===========================INITIAL REVIEWS===========================

ASME/ISI REVIEW : YARNES, R ASME XI R&R: DATE: 05SEP06
QC PLAN REVIEW : YARNES, R NQCR - DATE: 05SEP06
APPROVED BY : YARNES, R DATE:

=====================================================================

PRINT NAME AND WRITE INITIALS OF ALL PERSONNEL WHO INITIALED THIS ACTIVITY

RECURRING TASK ACTIVITY

W/O NBR : R2088493 01
A/R NBR : A2145128
W/O STATUS : HISTRY 29APR07
ACT STATUS : HISTRY 29APR07
TYPE : ACT



==========================ACTIVITY PROCEDURE LIST==============================

========================= HP SPECIAL INSTRUCTIONS =========================

* OC-1-05-00057 - MECHANICAL & ELECTRICAL MAINTENANCE, & NMD
* KNOWLEDGE OF THE RADIOLOGICAL CONDITIONS IS REQUIRED PRIOR TO ENTERING THE RCA UNLESS ESCORTED BY AN RP TECH.
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* SEE FIN RWP RADPRO RP JOB STANDARDS FOR RESIN CHARGE TO CATION TANK.

.

.

* THIS RWP IS NOT VALID FOR HRA,LHRA,VHRA.

1R21 REACTOR BUILDING GENERAL MAINTENANCE

* KNOWLEDGE OF RAD CONDITIONS REQ'D PRIOR TO ENTRY TO RCA W/OUT RPT ESCORT.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* WORKERS SHALL WEAR DOSIMETRY SO THEIR EXPOSURE CAN BE MONITORED IN ANY RCA.
* AIR SAMPLING PER RP
* OBTAIN CURRENT RADIOLOGICAL CONDITIONS FROM RP
* SURVEYS REQUIRED FOR OVERHEAD AREAS, SYSTEM BREACH, GRINDING AND DRILLING
* INTERFACE WITH RADPRO ON ALL WORK IN RCA
* DEBRIS HAS BEEN IDENTIFIED AS THE PRIMARY CAUSE OF FUEL FAILURE IN THE NUCLEAR INDUSTRY.EACH PERSON PERFORMING WORK ON A COMPONENT OR SYSTEM IN PLANT HAS THE RESPONSIBILITY TO BE THE PRIMARY BARRIER FOR PREVENTING THE ENTRY OF FOREIGN MATERIAL INTO THE COMPONENT OR SYSTEM.
* OC-1-06-00080 - REACTOR BUILDING HIGH RAD AREAS
* KNOWLEDGE OF THE RADIOLOGICAL CONDITIONS IS REQUIRED PRIOR TO ENTERING THE RCA UNLESS ESCORTED BY AN RP TECH.
* A DOCUMENTED HRA RP BRIEF IS REQUIRED FOR ALL ENTRIES INTO AREAS POSTED AS "LOCKED HIGH RADIATION AREA", AND "HIGH RADIATION AREA".(REF RP-AA-460)
* PC REQUIREMENTS PER RADIOLOGICAL POSTINGS OR PER RP.
* RADIOLOGICAL CONDITIONS CAN CHANGE BASED ON REACTOR POWER LEVEL, HYDROGEN INJECTION, RECIRC FLOW, SULFATE LEVEL AND WORK LOCATIONS. REMOTE MONITORS AND HISTORICAL DATA MAY BE USED.
* REFER TO RWP SUPPORT GUIDELINES FOR ADDITIONAL INFORMATION

NOT VALID FOR RWCU AREAS, SDC AREAS, RBEDT ROOM, OR TIP SHIELD AREA.

* RWP IS NOT VALID FOR VHRA'S AND D/W AT POWER.
* RPT TO PERFORM A SURVEY AT SYSTEM OPENING, OR ANY CHANGE IN CONDITIONS.
* DOSE RATE METER REQUIRED TO PULL TRASH/PCS FROM ANY HIGH RAD AREA, MATERIALS > 5MR/HR AT 30CM NEED RP COVERAGE PRIOR TO MOVEMENT.
* CONTACT RADENG FOR ANY TASK EXPECTED TO RECEIVE 50 MREM OR GREATER.

APPLICANT'S EXHIBIT 57

Paper No.
24

CORROSION96
The NACE International Annual Conference and Exposition

# CORROSION MANAGEMENT IN THE ARUN FIELD

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## ABSTRACT

A risk model has been developed to identify the probability that unacceptable downhole corrosion would occur as the Arun field was depleted. Using the life expectancy estimates for the carbon steel tubing strings from this model, optimized mitigation strategies could be developed to provide cost-effective alternatives for the management of corrosion.

Keywords: localized corrosion, downhole corrosion, condensate inhibition, corrosion risk model, extreme value statistics, Arun corrosion, life expectancy

## INTRODUCTION

The Arun field, located on the northern coast of the Aceh province in North Sumatra, Indonesia, is a gas condensate reservoir that was discovered in 1971 and has been in production since 1977. The reservoir is a compositionally dynamic system where retrograde condensation, condensate revaporization, water vaporization, mixing of lean injection gas, gas dehydration, and booster compression impact reservoir performance. In order to manage corrosion and its potential impact on gas deliverability, it was necessary to assess the probability that unacceptable downhole corrosion would occur as the Arun field was depleted. The changes in the wellbore environment over time which could influence corrosion kinetics had to be identified. Reservoir model data were used as inputs for a compositional tubing hydraulics program. This program generated pressure-temperature profiles in the wellbores as a function of depth, liquid dropout volumes for water and hydrocarbon phases, and the properties of the liquid films that develop during annular two-phase flow. Using multi-parameter regression analysis, results from field workover inspections, and laboratory corrosion testing, a corrosion risk model was developed to provide estimates of the life expectancy for the existing tubing in the Arun wellbores. Optimized mitigation strategies could then be developed to provide cost-effective alternatives for the management of corrosion.

## PREVIOUS WORK

A significant effort[1,2,3,4,5,6,7] has been expended in the evaluation of the probability for downhole corrosion as the field is depleted. The complexity of the downhole environmental systems and the potential synergy between the variables in these systems has presented a continuing challenge to those attempting to interpret dynamic corrosion behavior throughout the life of the reservoir. Predictions of the probability for unacceptable corrosion of the L80 tubing string completions in the Arun wellbores is complicated by the interactive variables in the environment, including wellstream composition, reservoir pressure, flow regime-pressure-temperature profiles in the tubing string, condensate quality and wetting characteristics, tubing metallurgy, shear stress, and water condensation and composition.

It has been known that with pressure depletion of the reservoir, substantial water vaporization would occur, resulting in an exponential increase in the water vapor fraction. No movement of the gas/water contact in the reservoir was anticipated so all liquid water production would be due to the condensation of water vapor. Due to the high production rates, the Arun wells have been in an annular mist flow regime with the majority of the liquid entrained in droplets in the flowing gas stream. As the pressure declines, less liquid hydrocarbon and more water is produced and the produced gas becomes leaner due to the reinjection of separator gas. The injected gas changes the composition of the reservoir gas and lowers the dew point pressure of the mixture.

In most condensate wells, the hydrocarbon condensate is produced along with a small amount of condensed water. However, if the water condenses in the production tubing string before the hydrocarbon condensate is formed, a corrosive condition may exist. When the tubing walls become wet with $CO_2$ saturated water, it is known that the corrosion rate can increase dramatically. Corrosion would be expected to be proportional to the time fraction that the metal is wetted on a microscopic scale by the aqueous phase. No corrosion would take place if the hydrocarbon is a continuous phase on the steel surface. Impingement of water droplets on the steel surface will, in effect, increase the amount of water exposure even if the oil phase is continuous on the steel surface. Thus, high flow rates can contribute to the water wetting and corrosion.[8]

### Liquid Volume Ratio of Water and Hydrocarbon

Some rules of thumb[9] have been developed regarding the water production rates and the wetting of steel surfaces. The interfacial properties of the liquids, both water and hydrocarbon, with steel will determine which species will preferentially wet the surface. Research[10] has indicated that the nature of the oil itself will affect these wetting tendencies.

Using the rules of thumb from field experience and the similarities between the Arun condensate and other condensates which have been studied, it was suspected that the Arun condensate may naturally inhibit corrosion under certain producing conditions. Based on field experience and experimental work with condensates reported in the literature, it was hypothesized that the volume ratio of liquid water to liquid hydrocarbon greater than about 0.5 (one-third water and two-thirds condensate) would be likely to result in corrosion, which could vary from mild to severe depending on the corrosivity of the acidic water.

Both liquid water and liquid condensate will condense out in a tubing string when their respective dew points have been reached. In a preliminary analysis with an initial version of a reservoir simulation model for the Arun field and a downhole tubing hydraulics program,[1] the liquid volumes for both water and hydrocarbon phases were estimated in one tubing string over time as the reservoir was depleted. Figure 1 shows the profiles of the volume ratio of liquid water to liquid hydrocarbon vs. the tubing temperature from bottomhole to the top of the tubing string. The increase in the volume ratio with time is evident. A zone of high probability corrosion damage was estimated with boundaries as the temperature range from 225 to 275°F (107 to 135°C), where previous work[3] had shown maximum susceptibility to localized corrosion, and a minimum value of 0.5 for the volume ratio of water to hydrocarbon. With this preliminary prediction, it was estimated that serious wellbore corrosion problems could be encountered at the top of this tubing string by the year 2000.

In order to attempt to identify possible alternatives to manage the occurrence of unacceptable corrosion, an interdisciplinary team then began to further refine the assumptions and to verify the hypothesized parameter ranges for corrosion damage for all 78 producing wells.

Reservoir Management Data

The downhole environment in Arun wellbores is the result of the complex interaction between thermodynamic and flow phenomena:

- As the Arun fluid undergoes retrograde condensation, liquid drops out in the reservoir and reduces well productivity. This changes inflow conditions such as bottomhole pressures and well production rates.
- As the reservoir depletes, and as injected gas breaks through, the composition of the fluid entering the wellstream changes.
- The temperature profile along the tubing string is determined by the type of completion fluid used, well rate, and wellstream compositions.
- Changes in the temperature and pressure along the tubing string result in hydrocarbon liquid dropout. The extent of such dropout increases initially as the pressure drops (retrograde condensation), then decreases as the pressure drops further (revaporization). The liquid volume also increases at cooler temperatures and varies with the fluid composition.
- The water vapor content of the wellstream increases rapidly as the reservoir pressure depletes. This water then condenses on the tubing string increasingly as it reaches lower temperatures and pressures.
- When the well rate drops below a critical point, the gas phase is unable to carry the entrained liquid and the well shuts down due to liquid loading.

All of these phenomena and their interaction were modeled using a compositional tubing hydraulics program. This program solves the thermodynamic, momentum, and energy equations to fully capture the above effects. It has been validated against field measured pressure traverses which have shown that the model predictions agree well with field data over a wide range of conditions.

In the reservoir, single phase flow is assumed, with liquid dropout effects captured in the form of an effective permeability. A simple pseudo-gas potential ($m(p)$) equation is used for this single-phase gas inflow, including non-Darcy effects. The wellbore calculations, however, are fully compositional and involve multiple phases. A correlation was developed for the Arun field, relating field-measured condensate-to-gas ratios (CGRs) and separator temperatures to the composition of the wellbore gas. This correlation, which accounts for compositional changes due to pressure depletion and mixing with injected lean gas, was verified against simulation results and a limited number of field composition measurements. The Peng-Robinson equation of state (EOS)[18] is used to model the thermodynamic equilibrium assumed prevalent in each of the tubing segments and a 9-component fluid model is used to represent the Arun gas condensate. The amount and compositions of each of the three phases (wellstream gas, liquid hydrocarbon, and liquid water) in each segment are determined by solving the thermodynamic equations.

Energy balance equations are used to model heat loss from the wellstream to the surroundings and the resulting temperature profile in the tubing string. The modified Gray correlation[19] for multi-phase flow is used to predict pressure drops in the segments, based on amount of liquid present, diameter and roughness of the segments, and properties of the various phases present. The compositional tubing hydraulics program can determine the tubing head pressure (THP) at a given well rate, or alternatively, predict the well rate at a given THP.

The downhole environment parameters for each of the 78 Arun wells were generated over the past producing life (history phase) and over the projected flowing life (prediction phase). In the history phase, field data sources such as the production database, buildup and shut-in pressure surveys, fluid analyses, and well diagrams were used to extract input data. Downhole environment parameters were generated for each month that the well was operational. The measured historical rates were specified as input, and the resulting tubing head pressures were matched to field measured values by tuning the effective permeability in the inflow equations.

In the predictive phase, results from the Arun full-field reservoir simulation study played a crucial role. Reservoir pressure decline, wellstream composition changes, and tubing head pressures were extracted from the simulation runs. Calculations were carried out into the future for as long as the well would produce above the loading rate. When the well loaded, the tubing size was reduced and calculations were resumed. When the well loaded with a 3.5-inch (8.89 cm) inner diameter tubing string, it was assumed to be permanently shut-in.

Multi-parameter Regression Analysis

The inspection data from the workovers of fourteen Arun wells, which had not been exposed to acid stimulation fluids, provided maximum pit depth data based on measurements of remaining wall thicknesses. The production lives of these fourteen wells ranged from 1.6 to 11.7 years with maximum localized corrosion (pit) penetration rates ranging from 0 to 225 mils per year (mpy) (5.72 mm/y) for the 7-inch (17.78 cm) L80 tubing with a nominal wall thickness of 0.498-inch (1.265 cm). The monthly outputs from the corresponding history phase calculations for each of these wells generated downhole environment parameters for each tubing string segment which included the liquid water and liquid hydrocarbon dropout volumes, liquid film thicknesses and velocities, shear stresses, surface tension, gas and liquid densities and viscosities, superficial gas and liquid velocities, temperatures, and pressures, and individual wellstream components. In addition to the outputs, $H_2S$ and $CO_2$ concentrations and produced water compositions along with conductivity, total dissolved solids, and pH data were also available from field measurements of test separator samples.

The maximum corrosion penetration rate was used in multi-parameter regression fits against combinations of 65 independent variables to examine the relative influences of the parameters in explaining the variation in the corrosion rates. Polynomial fits were attempted with single variables and combinations of variables. The following quadratic equation expresses a relationship for which the analysis of variance indicated statistical significance:

$$\text{Maximum Penetration Rate (mpy)} = 0.75 + 143.6\,(H_2O/HC) + 430.1\,(H_2O/HC)^2$$

The variable ($H_2O/HC$) is the volume ratio of liquid water to liquid hydrocarbon on the tubing walls. Figure 2 depicts the relationship graphically. The degree of fit could only be improved marginally with the addition of, or interaction with, other variables. This relationship, while certainly not explaining all of the variability in the corrosion response, suggested that the ratio of liquid water to liquid hydrocarbon was a parameter that had a significant influence on the corrosion behavior of the L80 carbon steel tubing strings in the Arun field.

Natural Corrosion Inhibition by Arun Condensate

Experimental work was then conducted to confirm the degree of natural corrosion inhibition provided by the Arun condensate. Using the reservoir simulation data for field production through the year 2000, critical variable ranges were established to simulate a severe scenario in the future in which the highest acid gas partial pressures would occur within the temperature range from 225 to 275°F (107 to 135 °C). This worst case environment would occur when wellhead pressure and temperature declined to approximately 2000 psi (13790 kPa) and 250°F (121°C), respectively. Corresponding partial pressures for $CO_2$ and $H_2S$ were established as 300 psi (2069 kPa) and 0.1 psi (0.69 kPa), respectively.

Arun produced water containing 55 ppm chlorides, simulated in the laboratory, and stabilized Arun condensate from the field were used with various L80 carbon steel tubular metallurgies.

Preliminary work was conducted using a flowloop at the University of Aachen, Germany with water to hydrocarbon ratios of 1.0 (50% water: 50% condensate) and 0.25 (20% water: 80% condensate). Localized corrosion, as reflected by a maximum local penetration rate, assuming that a pinhole shaped pit would continue to penetrate the wall thickness of the tubing, was calculated from the pit depth measurements taken using a laser profilometer system. Irrespective of the exact nature of the L80 carbon steel metallurgy tested, both maximum local penetration rate and the general weight loss corrosion rate were significantly reduced as the relative condensate volume was increased. Extensive laboratory work was then conducted to characterize the Arun condensate and evaluate the influence of the water to hydrocarbon ratio on the corrosion behavior under Arun wellbore conditions.

Since the preliminary work had shown that both localized corrosion and general weight loss corrosion had been reduced as the condensate volume increased, an experimental program was designed to quantify the effects of varying the fluid volume ratio, first through the use a short exposure screening test and, subsequently, with longer exposure stirred autoclave tests. The screening tests were conducted under atmospheric pressure at 130°F (54°C) for 10 hours using $CO_2$ gas with 1000 ppm $H_2S$ in a total liquid volume of 30 ml. The apparatus is depicted in Figure 3. The specimen surface area to water volume ratio was maintained at a minimum of 15 cm.

Autoclave testing was conducted using a fixed cage configuration in one-gallon autoclaves as shown in Figure 4. Exposure time in these tests was 72 hours with the partial pressures and temperature representative of the severe conditions previously referenced. A specimen surface area to liquid water volume ratio of 25 cm was maintained throughout this testing. Unlike previous testing using a high speed rotating cage configuration(2), the cage was fixed and auxiliary propellers were used for stirring. Liquid samples withdrawn from the autoclaves at various depths demonstrated that the propeller configuration and rotation rate significantly influenced the degree of mixing of the water and the condensate fluids. Sufficient mixing to properly expose the steel coupons to the appropriate fluid volume ratio could only be achieved with a fixed cage configuration.

Figure 5 summarizes the influence of water to hydrocarbon ratios on the general weight loss rates and the localized penetration rates from the autoclave tests. At a water to hydrocarbon ratio of 0.25 (20% water, 80% hydrocarbon), the significant inhibiting influence of the Arun condensate is very evident for both localized as well as general corrosion. Realizing that the composition of the condensate would change over time and, in particular, that the higher molecular weight fractions were likely to remain in the reservoir as the pressure diminished, it became important to isolate the range of the inhibiting components and their effectiveness. Molecular characterization of ten representative samples of the Arun condensate over the period from 1979 to 1991 demonstrated that the condensates became slightly depleted in compounds > n-$C_{11}$ and enriched in the lighter hydrocarbon compounds.

A spinning band vacuum distillation unit was then used to separate the Arun condensate into groups of components. The composition of each of the distillation cuts was verified with gas chromatography. Screening tests were conducted to attempt to isolate the range of inhibiting components within the condensate. Figure 6 shows the corrosion responses for the various condensate composition ranges of the distillates at a constant water to hydrocarbon ratio of 14. Clearly, the inhibiting components resided in the component range > n-$C_{13}$ and most likely within the band from n-$C_{15}$ to n-$C_{23}$. Detailed molecular analysis indicated that the alkylated carbazoles could be responsible for the inhibition. A trend analysis of changes in molecular character with time indicated that the carbazoles in the range of n-$C_{17}$ to n-$C_{22}$ would be expected to remain throughout the flowing life of the reservoir.

## Alloy Alternatives

To evaluate other corrosion mitigation opportunities, autoclave testing was also conducted on a variety of 13% chrome alloys, a 15% chrome material, and on 9% chrome-1% molybdenum tubular materials. Table 1 summarizes the test conditions that were used to evaluate the corrosion performance of these materials. No localized corrosion was exhibited by any of the 13% chrome materials or the 15% chrome material tested. The 9% chrome-1% molybdenum materials exhibited slight pitting when exposed to the conditions in test A. Slow strain rate testing of the 13% chrome materials in 300°F (149°C) deoxygenated Arun water at 300 psi (2069 kPa) $CO_2$ partial pressure and $H_2S$ partial pressures ranging from 0.06 (0.41 kPa) to 0.1 psi (0.69 kPa) with a strain rate of 1x 10 E-6 in. / sec. ($2.5 \times 10^{-5}$ mm/sec.) did not exhibit any evidence of sulfide stress corrosion cracking susceptibility. The 13% chrome alloys were thus viable corrosion mitigation alternatives for the wellbore environmental conditions projected to be prevalent during the remaining flowing life of the Arun wells.

## Corrosion Risk Model Development

It is customary when characterizing the localized corrosion response of a material to measure the maximum pit depth from the distribution of pit depths that are visible and use that pit depth and the exposure time to calculate the maximum penetration rate. In a similar fashion, pit depth measurements reported from workover inspections or caliper logging reflect the maximum pit depths encountered along the lengths of the tubulars.

The classical applications of statistical methods which deal with average values or symmetrical distributions become inadequate when the parameters of interest are the largest or smallest in the range of possible values. The distribution curve of largest values is skewed with the maximum to the left of the mean and exhibits a long tail extending to the right side. This distribution follows mathematical rigor represented by extreme value statistics.[11] Applications for extreme value techniques have included gust velocities for airplanes, extinction times for bacteria, and extremes in meteorological phenomena including floods and droughts. There have also been applications of extreme value statistics to the depths of corrosion pits.[12,13,14]

In using the extreme-value methodology,[15,16,17] all the observed maxima are ranked in order of size from the smallest to the largest. A plotting position is determined for each observation by associating a probability P, where $P = i / (n+1)$ with each observed maximum value (n). The (i) is the rank of the observation, starting with the smallest. When the data are plotted on extreme-value probability paper, an ideal extreme value distribution will plot exactly as a straight line. The closeness of plotted points to a straight line is an indication of how well the data fit the extreme value theory. Figure 7 provides examples of the extreme value fits for two sources of corrosion rate data: pit depths from field workover inspections and pit depths from autoclave testing. The high $r^2$ values indicate that the extreme value theory is followed relatively well. The degree of fit improves with large data sets and with the use of accurate and reproducible measuring devices.

Using the extreme value fits for field workover, corrosion logging, and laboratory data, a series of extreme value equations with the best fits ($r^2 > .95$) was assembled and plotted collectively. The volume ratio of liquid water to liquid hydrocarbon generated from the tubing hydraulics calculations that corresponded to the exposure time and tubing segment location for each extreme fit line were superimposed on the collective plot. Figure 8 shows the composite plot of the extreme value lines and the water to hydrocarbon ratios. Clearly, the slope of the extreme value line increased as the water to hydrocarbon ratio increased.

Using the extreme value lines, it then became possible to estimate a tubing life expectancy for exposure to the corresponding volume ratios of water to hydrocarbon in the wellbore. Tabulated probability values[15] can be used to calculate the corrosion rate at a 95% probability from the variate, which was the horizontal axis on the extreme value probability paper. When the nominal wall thickness of the tubing, 0.498 inch (1.265 cm), was divided by the corrosion rate at a 95% probability, the life expectancy in years was estimated for the full wall penetration by a corrosion pit.

The estimated life expectancy associated with the volume ratio of liquid water to liquid hydrocarbon to which a portion of the tubing string was exposed constituted the framework of the corrosion risk model. The model is based on probability and is not intended, nor should it be used, to provide quantitative corrosion rate information. It cannot guarantee that corrosion will occur or when it will occur but provides a risk assessment of the potential that it might occur and when it might occur. It can be used as a tool to forecast the influence of corrosion damage on gas deliverability and to evaluate potential scenarios involving investments in corrosion mitigation alternatives.

As shown in Figure 9, as the reservoir pressure drops over time, the volume ratio of liquid water to liquid hydrocarbon increases to large values. However, the wellbore environment conditions are unique for each well and the change in the ratio with time differed for each of the 78 wells. The mean volume of liquid water and the mean volume of liquid hydrocarbon within a tubing segment was calculated from the monthly outputs over two-year producing increments. The ratio of the two means was calculated and the appropriate coefficients from the extreme value equation were selected to represent that time interval. This was repeated for approximately two-year time steps until the production for each well had been terminated.

An iterative computer program was written to use the inputs from the two-year increments to calculate the cumulative pit depths for incremental time steps assuming that once a pit is initiated, it penetrates the tubing wall continuously if the wellbore environment conditions are corrosive. Time increments of less than two years were not used due to evidence of large, non-random variability in the mean fluid volumes. A 95% probability was used to calculate the life expectancy for the full-wall penetration of the tubing using a best case, a mid-case, and a worst case scenario. The life expectancy was also calculated for smaller increments of wall thickness penetration where the designed structural capacity of the tubing under pressure may have been at risk.

The validity of the model was evaluated using corrosion pit depth data from workover inspections and corrosion logging that had not been used in the development of the model. Figure 10 is a graphical depiction of the correspondence between the risk model predictions for the range of wall thickness and those measured. From this, it was established that there was at least an 80% confidence level for a 95% probability of corrosion risk. This corrosion risk model was then applied to calculate the life expectancies of the carbon steel tubing in each of the tubing segments for each of the 78 wells.

Figure 11 summarizes the comparison of the predicted life expectancy at the uppermost tubing segment of the well vs. the projected flowing life for 18 of the wells. The prediction shows that penetration of the tubing wall will occur due to corrosion in all but a few of the wells prior to the end of their flowing life. In some wells, the tubing penetration would be projected to occur one to two years in advance of a tubing size reduction necessitated by liquid loading conditions in the well. The impact of an earlier-than-expected recompletion to a smaller tubing size on gas deliverability needed to be taken into account in the development of an optimized corrosion management program.

The tubing wall penetration occurs because the natural inhibition protection afforded by the Arun condensate has been diminished by the increasing liquid water volume on the tubing walls. Corrosion mitigation alternatives under consideration included condensate reinjection to adjust the volume ratio of liquid water to liquid hydrocarbon to lower ranges and workovers to replace some or all of the tubing with carbon steel or 13% chrome alloy. Life expectancy calculations were made for each tubing segment in a well, at intervals of 1000 feet or less, in order to evaluate the depth requirement for corrosion mitigation alternatives. The projected depth requirement for the corrosion mitigation varied from well to well but generally averaged approximately the upper-half of the total completion length.

Figure 12 summarizes the life expectancy projections for the uppermost tubing segment after the recompletion of the 18 wells shown in Figure 11 with new L80 carbon steel. In this scenario, the wells were recompleted just prior to the earliest point in time that wall penetration was projected to occur for the original tubing. Of the 18 wells recompleted, half would now be expected to survive until the tubing was changed out and replaced with 5-1/2-inch (14 cm) diameter tubing to maintain the flowing life of the wells.

Corrosion risk model calculations were conducted for a variety of scenarios for each well in order to weigh the impact of the corrosion risk over time on gas deliverability and the cost of the corrosion mitigation option. A corrosion management program emerged from these scenarios that incorporated the most cost-effective combination of the alternatives for the remaining life of the field. The optimized corrosion management program consisted of a combination of the 13% chrome alloy and carbon steel tubing in some wells and the use of carbon steel tubing in others. Corrosion monitoring will continue to provide feedback data for the refinement of the risk model and its application for the cost-effective management of corrosion as the Arun field depletes.

## CONCLUSIONS

1. The integration of reservoir simulation data, tubing hydraulics calculations of the downhole wellbore environments, and the corrosion pit distributions from field data and laboratory experiments provided the framework for the development of a corrosion risk model.

2. A multi-parameter regression showed that the volume ratio of liquid water to liquid hydrocarbon on the tubing walls had a significant influence on corrosion behavior in the Arun field.

3. The Arun condensate provided natural corrosion inhibition for carbon steel tubing at a volume ratio of liquid water to liquid hydrocarbon of 0.25.

4. Extreme value methodology provided a good representation of the distribution of corrosion pit depths from field workover inspection, corrosion logging, and laboratory data.

5. A validity analysis of the risk model with a 95% corrosion probability indicated that there was at least an 80% confidence level for the prediction.

6. Life expectancy calculations using the corrosion risk model provided the basis to develop an optimized corrosion management strategy to minimize the impact of corrosion on gas deliverability as the reservoir depletes.

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TABLE 1
AUTOCLAVE CONDITIONS USED TO EVALUATE CHROME ALLOYS

| Test | Environment | Temperature (°F) | ExposureTime (hrs.) |
|---|---|---|---|
| A. | Air saturated Arun simulated water, 300 psi $CO_2$, 0.1 psi $H_2S$ partial pressure | 250 | 72 |
| B. | Test A conditions but with non-deoxygenated Arun simulated water | 250 | 72 |
| C. | Test A conditions but with deoxygenated Arun simulated water | 250 | 72 |
| D. | Test A conditions but with deoxygenated Arun simulated water | 300 | 72 |
| E. | Test A conditions but with deoxygenated Arun simulated water | 350 | 72 |
| F. | Deoxygenated Arun simulated water and Arun condensate at a volume ratio of 4, with 300 psi $CO_2$, 0.1 psi $H_2S$ partial pressure | 250 | 72 |
| G. | Test F conditions but with a volume ratio of 14 | 250 | 72 |

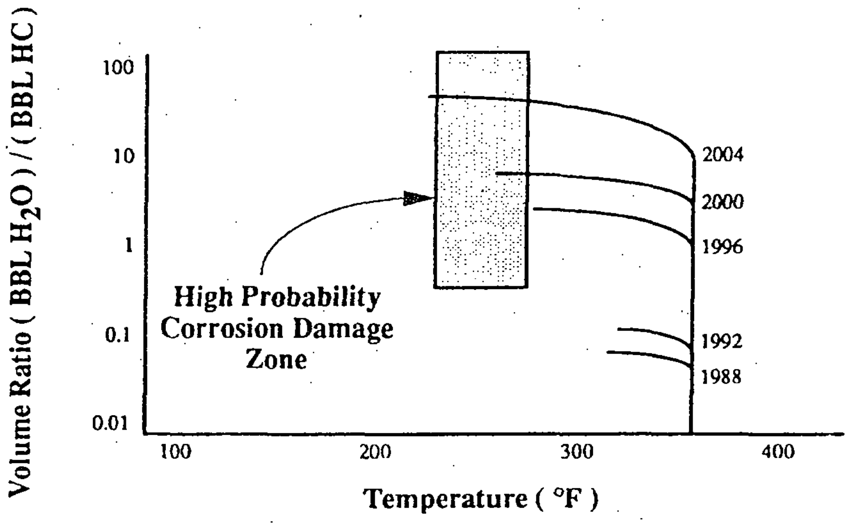


*Figure 1.* Fluid volume ratio profiles from the bottom to the top of the tubing string in one Arun well throughout time. The boundaries of the high probability corrosion damage zone are superimposed. The bottomhole temperature is approximately 325°F (178°C) throughout time. (1 mpy=0.0254 mm/yr)

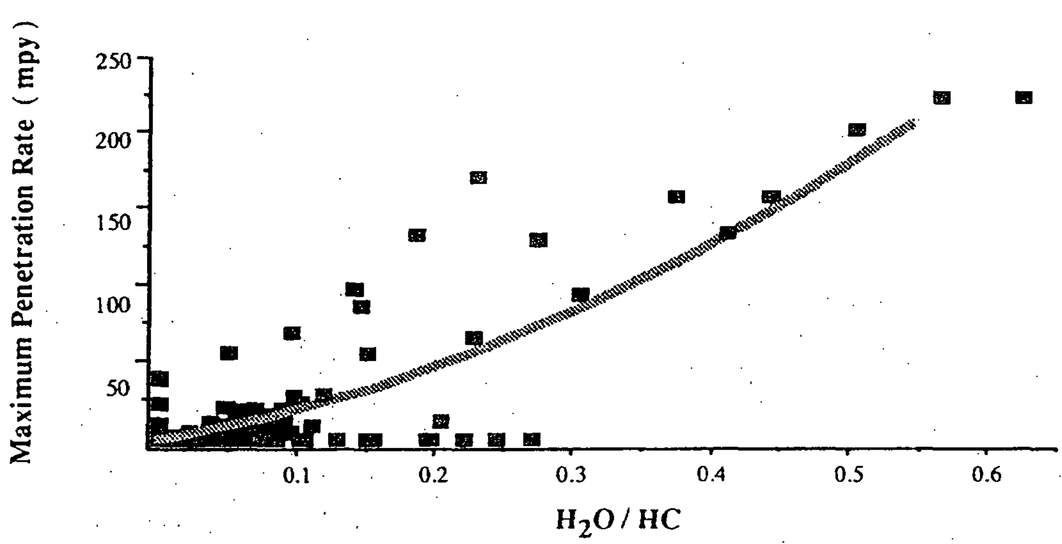


*Figure 2.* The quadratic fit for the volume ratio of liquid water to liquid hydrocarbon on the tubing walls vs. the maximum corrosion penetration rate in mils per year. The $r^2$ correlation coefficient for the fit was 0.749. (1 mpy = 0.0254 mm/yr)

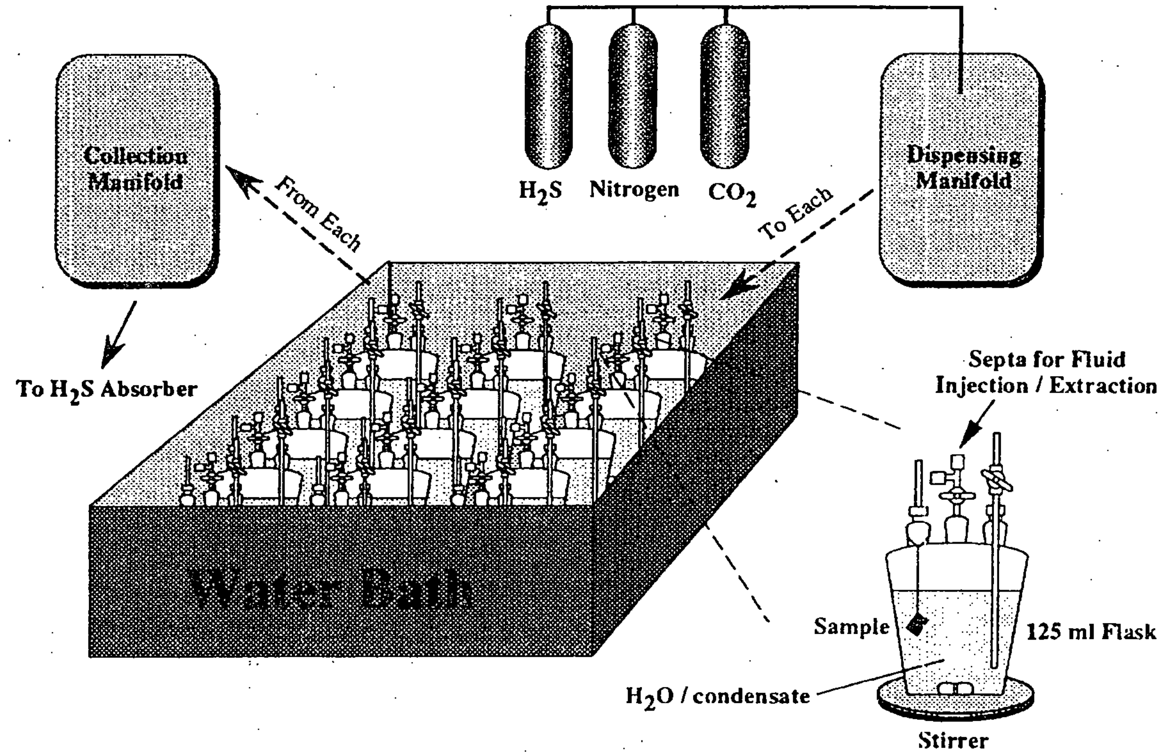


*Figure 3.* Atmospheric Screening Test Apparatus

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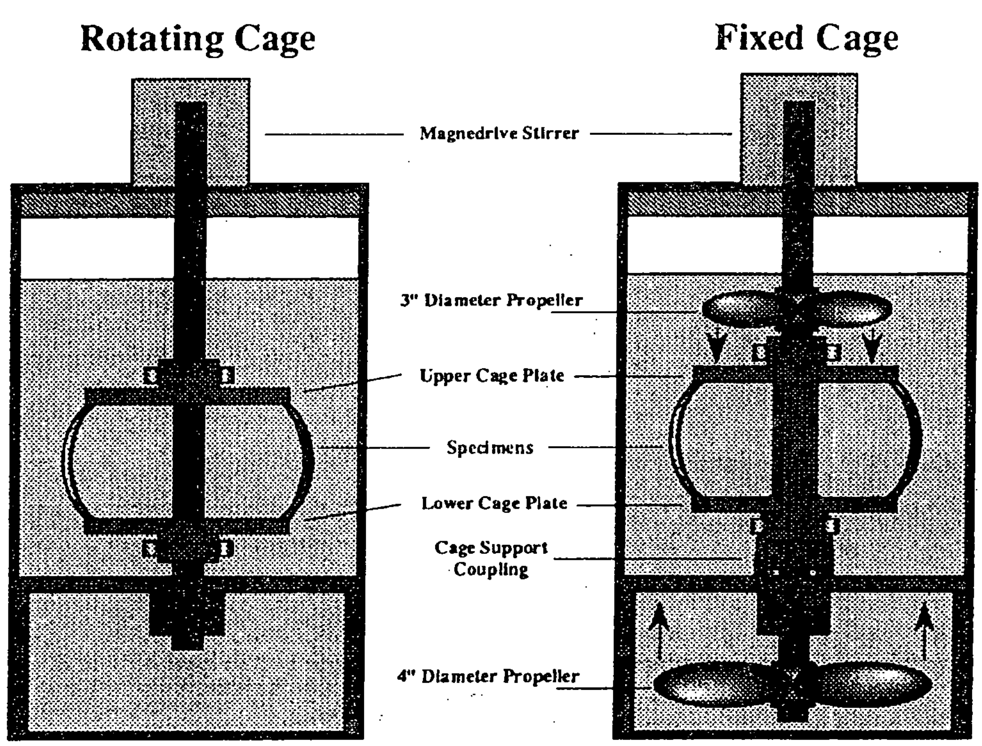


*Figure 4.* Comparison of autoclave test configurations for a rotating cage and a fixed cage. (1 inch = 2.54 cm)

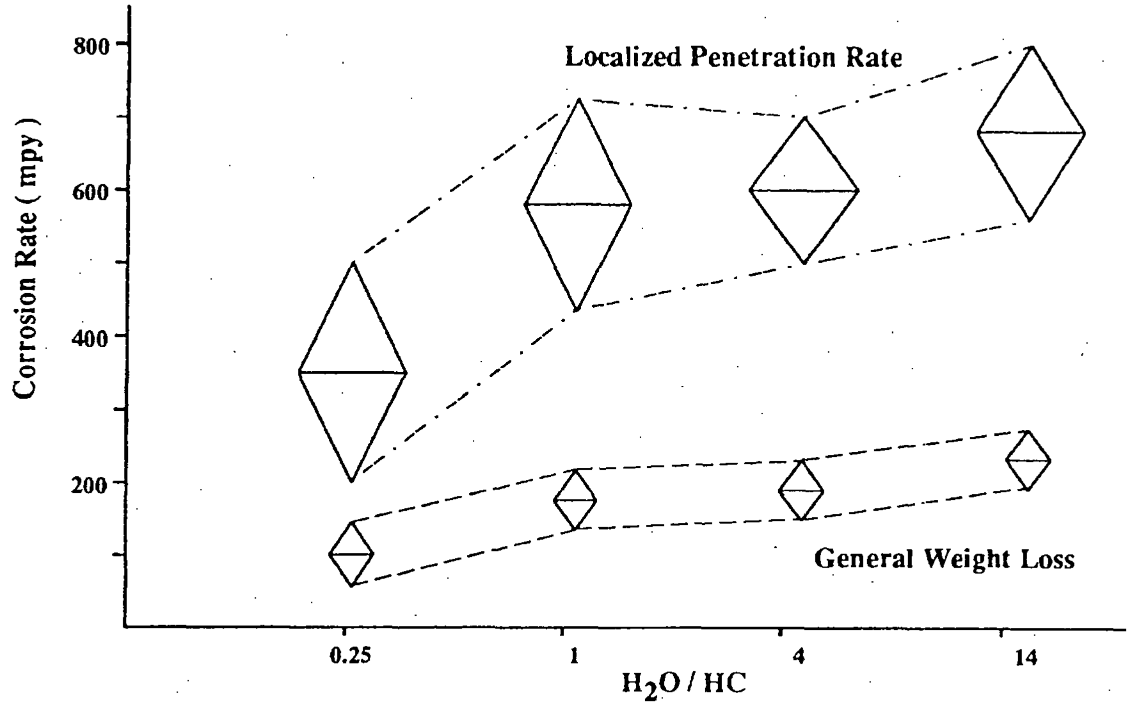


*Figure 5.* Influence of volume ratio of liquid water to liquid hydrocarbon on general weight loss corrosion rates and on maximum localized penetration rates from autoclave tests. The size of the diamond represents the 95% confidence about the mean, shown as the horizontal line. (1 mpy = 0.0254 mm/yr)

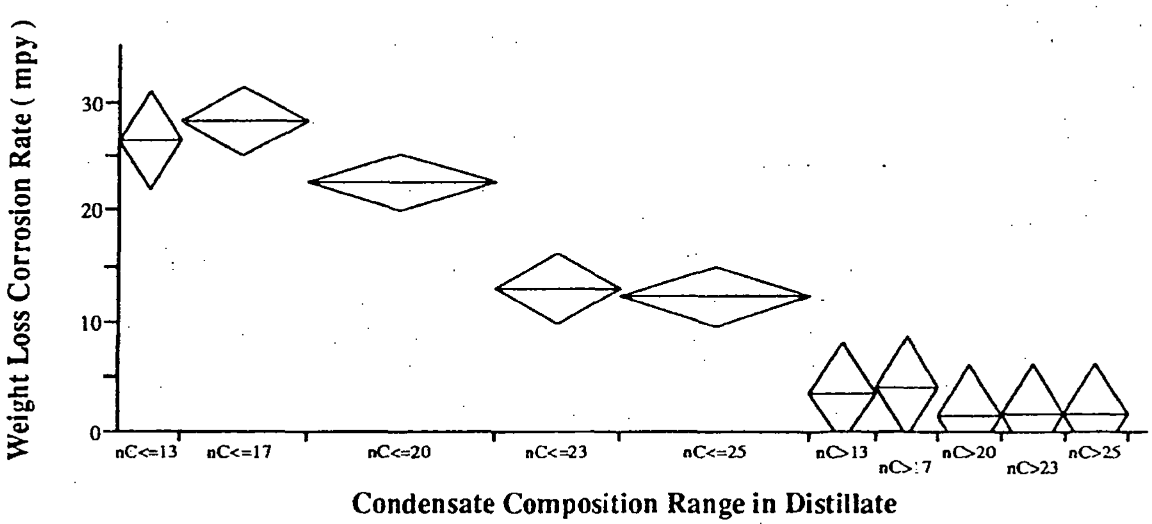


*Figure 6.* Weight loss corrosion rates for the compositional ranges in the condensate distillates as determined by the screening test at a constant volume ratio of liquid water to liquid condensate distillate fraction of 14. ( 1 mpy = 0.0254 mm/yr)

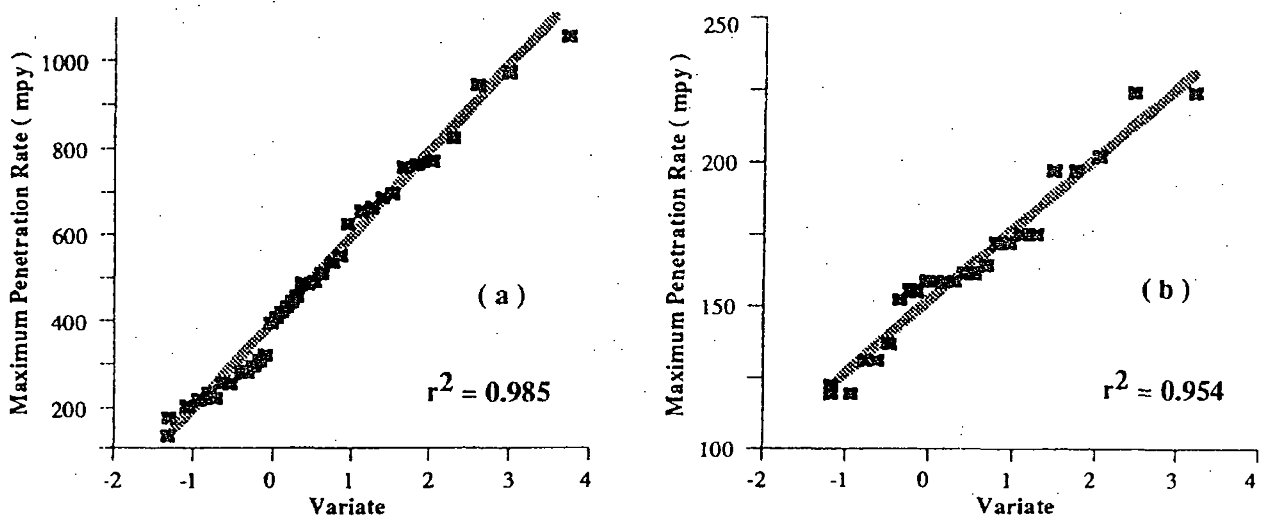


*Figure 7.* Extreme value plots for laboratory autoclave tests with Arun saturated water only ( a ) and for field workover data from a well ( b ). (1 mpy = 0.0254 mm/yr)

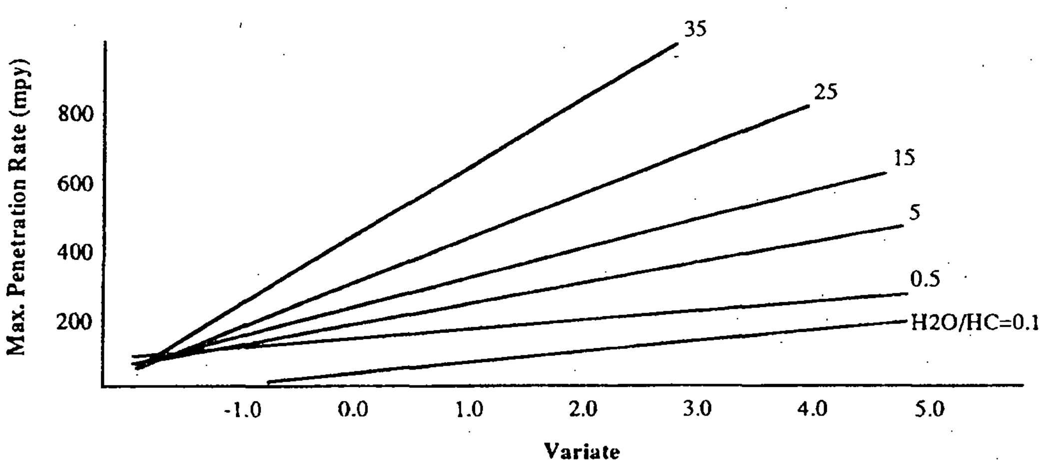


*Figure 8.* Composite plot of extreme value fits for both field and laboratory data and corresponding volume ratios of liquid water to liquid hydrocarbon. (1 mpy = 0.0254 mm/yr)

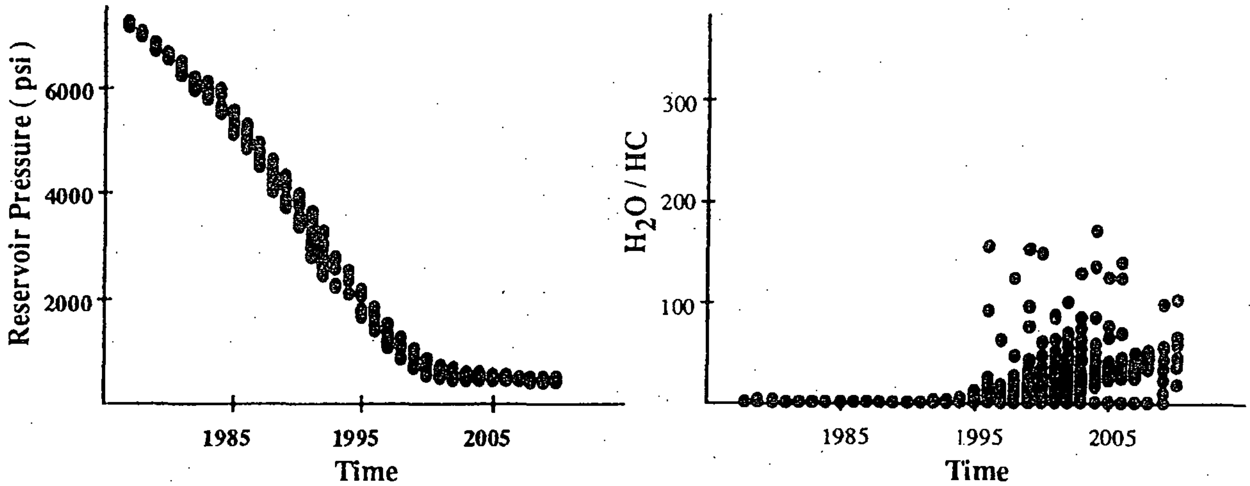


*Figure 9.* Changes in reservoir pressure and the volume ratio of liquid water to liquid hydrocarbon over time from reservoir simulation and the tubing hydraulics calculations. ( 1 psi = 6.895 kPa )

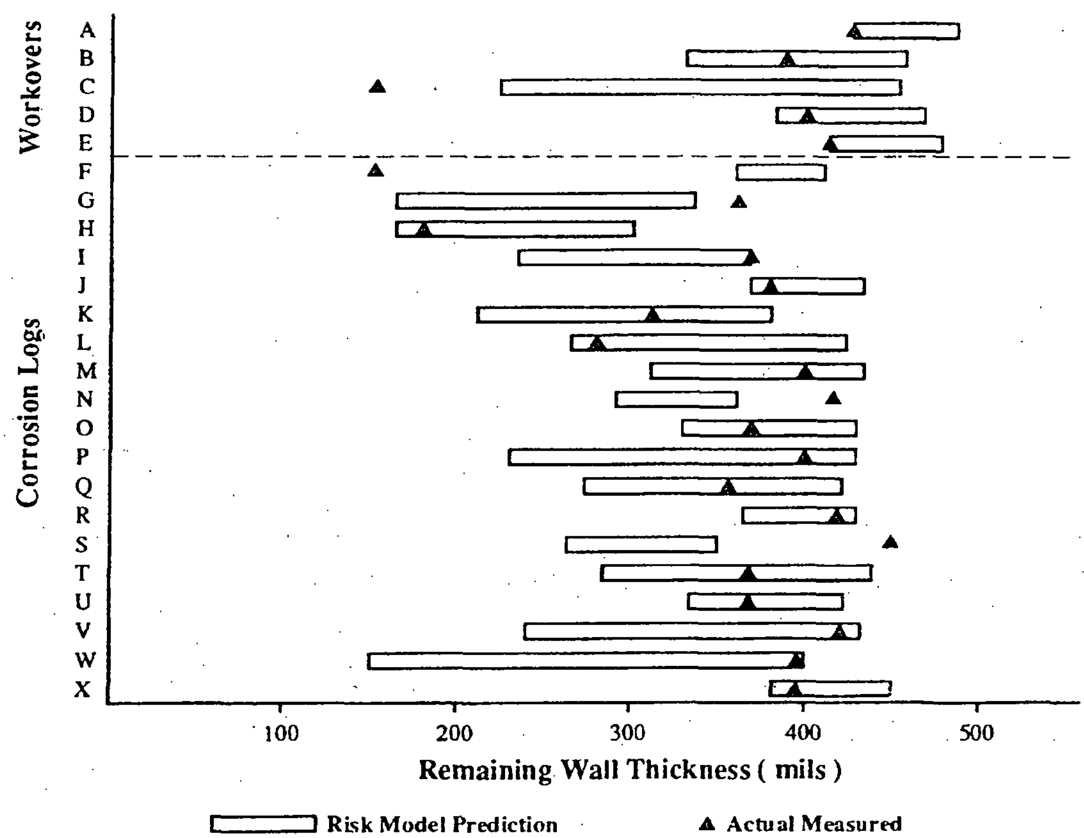


*Figure 10.* Summary of validity check for corrosion risk model with workover and corrosion logging data. (1 mil = 0.0254 mm)

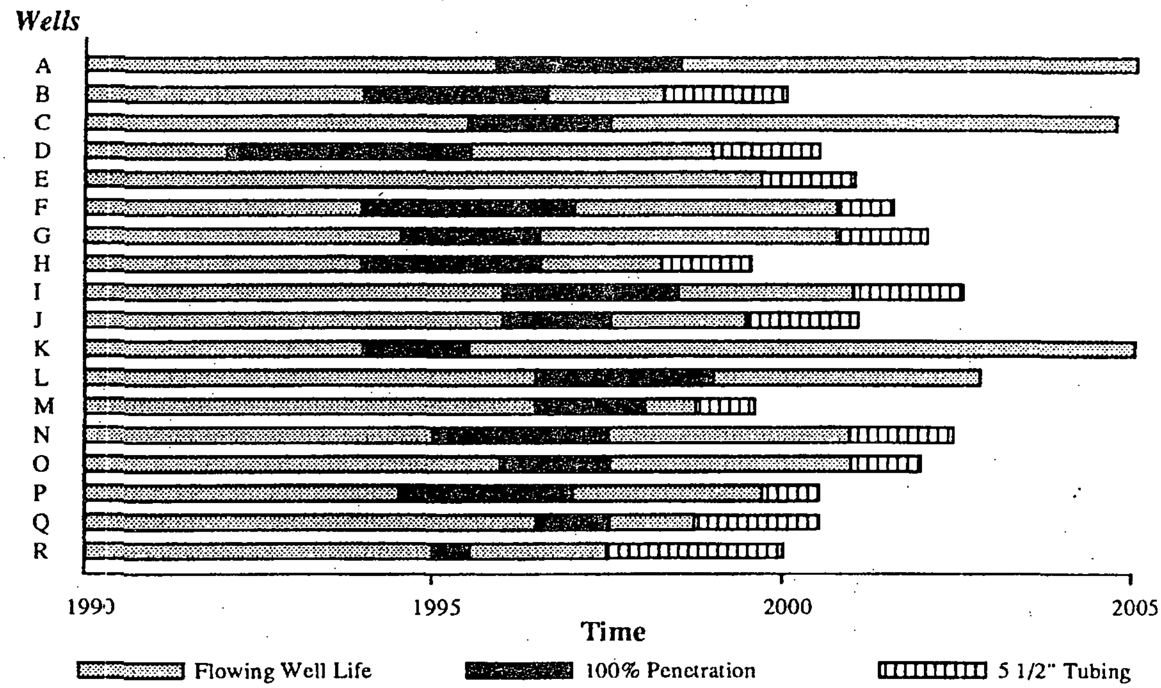


*Figure 11.* Summary of the life expectancies for the uppermost segment of carbon steel strings in 18 Arun wells based on the corrosion risk model estimates. A comparison is made with the flowing well life and the projected timing for recompletion with 5 1/2" ( 14 cm ) tubing is shown.

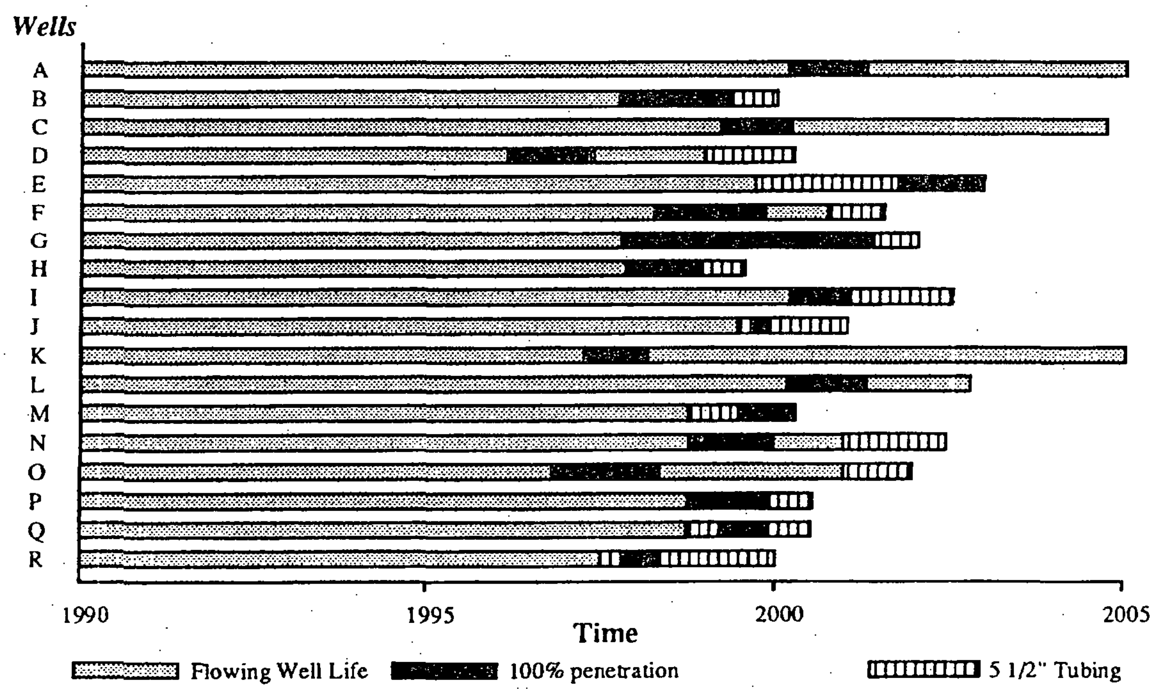


*Figure 12.* Summary of the life expectancies for the uppermost segment of carbon steel tubing strings in the same 18 Arun wells in *Figure 11*, for which recompletion was made with new carbon steel prior to the onset of wall penetration of the original tubing. ( 5 1/2" = 14 cm )

APPLICANT'S EXHIBIT 58

Paper No.

2

CORROSION99

# Development of a Corrosion Inhibition Model
# I: Laboratory Studies


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## ABSTRACT

The production of a $CO_2$ flood in the Oklahoma panhandle led to severe corrosion of the carbon steel production tubing and casing. Traditional approaches to chemical corrosion inhibition were unsuccessful. A laboratory study was initiated to determine first the best corrosion inhibitor, and second the optimum effective inhibitor concentration in the produced fluids as a function of the production rate, $CO_2$ partial pressure, and water to oil ratio. The tool used was the high speed autoclave test (HSACT) discussed in earlier publications. Statistical experimental designs were used to study the three major parameters. The results were expressed in terms of the inhibitor concentration necessary to achieve a desired corrosion rate (for example 1 mpy), and presented either in the form of response surfaces or linear multiple regression equations. While it was generally known that higher fluid velocities require a higher inhibitor concentration for equal target corrosion rates, it was less well appreciated that the $CO_2$ partial pressure also has a significant effect on the effective inhibitor concentration. The model as represented either by the response surface or the predictive equations is both inhibitor and field specific.



Keywords: carbon dioxide, fluid velocity, partial pressure, corrosion inhibitor, modeling, statistical design, response surface, effective inhibitor concentration, target corrosion rate,

## BACKGROUND

### 1. Introduction

Mobil E & P US, Inc. operate a $CO_2$ flood in Texas County, Oklahoma which is known as the Postle Field. The Field produces from the Morrow Sand formation at a depth of 6000 ft., The field was discovered in 1958 and has been in continuous production since that time. $CO_2$ flooding began in November 1995 and severe corrosion was experienced on select wells in this field shortly after $CO_2$ breakthrough. The corrosion was extremely rapid, new tubing strings would be severely damaged, both internally and externally and a number of casing failures occurred. The corrosion took the form of typical flow induced corrosion, with a MESA pattern and penetration rates in excess of 300mpy. The corrosion was reported, by field personnel, to be associated with $CO_2$ breakthrough corrosion pattern throughout the field was irregular, however. Although the $CO_2$ was moving through the formation exactly as planned, and $CO_2$ breakthrough was predictable some wells would experience severe corrosion and others would not.

Typically, sandstone formations, when flooded with $CO_2$, generate a more corrosive environment on the production side than limestone (carbonaceous) formations (Ref 1). Not only is corrosion more severe, but it is also more difficult to chemically inhibit with traditional corrosion inhibitors (Ref 2, 3). There are many reasons for this. The lower bicarbonate concentrations often found in brines from sandstone formations result in lower pH's, particularly when $CO_2$ is produced back at increased partial pressure. $CO_2$ breakthrough also leads to increased liquid volumes produced through the production tubing, or the casing space in the case of packerless completions.

It has been demonstrated in numerous generic studies (Ref 4) that the effective corrosion inhibitor concentration i.e. the concentration required to achieve a specified (low) corrosion rate depends, amongst other things, upon in situ pH, the relative liquid velocity [1)] and the oil/water ratio. When formulating a corrosion inhibition program for a field, these 3 variables must be taken into account but are sometimes overlooked. This paper describes the work undertaken to develop a corrosion inhibition model for the Postle Field which takes account of all the important production variables.

### 2. Previous Experience

Extensive laboratory and field studies had been undertaken in the mid 1980's in an effort to bring corrosion in Shell's Little Creek (Mississippi) $CO_2$ flood under control (Ref. 5, 6). This is also a sandstone flood, albeit from greater depths (14,000 to 15,000 ft) and therefore with higher shut-in bottomhole pressures (6000 psi). Upon $CO_2$ breakthrough, bare tubing had been observed to corrode uniformly and with pronounced mesa type attack to less than half of its original thickness in 3 to 4 months with the most severe damage occurring at the upstream pinends. The effectiveness of the chemical corrosion inhibition program was monitored with coupons installed at either the well head, or the high and low pressure manifolds to the plant inlet where the flowlines from different wells came

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[1)] The linear liquid velocity relative to the metal surface.

together. Along with the corrosion, production rates and $CO_2$ partial pressures were monitored and associated with the individual coupon corrosion rates for the period of exposure. After over 240 corrosion rate data points had been accumulated, a least squares multiple linear regression analysis was attempted over the following parameter space:

**Table 1**

| **Parameters Monitored** | **Significant Parameters** | **Natural log of Effect** |
|---|---|---|
| Superficial Gas Velocity | yes | 0.252302 |
| Superficial Liquid Velocity | yes | 0.674294 |
| Type of Inhibitor (A, B,) | yes | A +0.539158<br>B – 0.539158 |
| Inhibitor Concentration | no | - |
| Water Prod. Bbl/MMscf | no | - |
| $CO_2$ Partial Pressure, P | yes | - 0.228016 |
| Water/Oil Ratio | yes | - 0.199186 |
| Natural log of Identity (intercept) | | 1.065763 |

The resulting correlation equation for Inhibitor A has the following form:

$$\ln(\text{corr. rate}) = 1.066 + 0.5392 + \ln(U_{SG})*0.2532 + \ln(U_{SL})*0.6743 + \ln(\text{Water/Oil})*(-0.1992) + \ln(P)*(-0.2280)\ (^*) \quad (1)$$

The factors were significant at the $95^{+}\%$ level except for the pressure (93 %). In interpreting these results one must remember, that all corrosion rates were obtained under inhibited conditions and at the low temperatures prevailing on the surface. The effects therefore are relatively small, but nevertheless indicate that inhibitor B was about 3 times as effective as inhibitor A, a result that had been predicted from laboratory studies. The inhibitor concentration did not seem to affect the corrosion rate, because essentially all results had been obtained at near-constant inhibitor concentrations. The superficial gas and liquid velocity effects were both positive as expected. However, the negative effects of the water/oil ratio and the pressure were surprises.

Since the inhibitors were both oil soluble and had very little water solubility and/or dispersibility, and since furthermore the dosage was based on total fluid production, it was argued that a higher water/oil ratio would increase the inhibitor concentration in the oil, and thereby increasing inhibition (lowering the corrosion rate) under turbulent conditions in the production tubing and flowlines. The thought was that an increased inhibitor concentration in the oil would lead to more effective adsorption on the metal surface, even though with the increased water cut the frequency of oil droplets in turbulent flow contacting the metal surface might be diminished. It should be added that such an effect is probably inhibitor specific and might be observed only with oil soluble poorly dispersible compounds. Figures 1

(*) for Inhibitor B the second number in equation 1 would have a negative sign indicating superior activity.

and 2 show calculated corrosion rates for Inhibitor A first as a function of the superficial gas and liquid flow rates (Fig. 1) and then as a function of the water/oil ratio and the $CO_2$ partial pressure (Fig. 2).

The pressure effect was clearly unexpected and contrary to everything that had been known previously. For this reason it was studied more extensively in the laboratory.

### 3. Laboratory Studies of Pressure Effect

The high-speed autoclave rotating cage methodology (Ref. 7, 8 ) was chosen for this investigation. The test conditions are summarized in Table 2:

**Table 2**

| Parameter | Value |
|---|---|
| Brine | 100,000 ppm $Cl^-$<br>10,000 ppm $Ca^{++}$<br>1,000 ppm $Mg^{++}$ |
| Autoclave | 3.75 L |
| Brine Vol. | 1800 ml |
| Hydrocarbon | Isopar M |
| Hydrocarbon Vol. | 200 ml |
| Inhibitor (concentration in active ingredients) | B |
| Corrosion Coupons | L-80 |
| Coupon size (4 per test) | 30 $cm^3$ |
| Temperature | 125 F |
| Gas | $CO_2$ |
| Pressure | Variable |
| Speed of rotation of cage | 1500 rpm |
| Test duration | 100 hrs |

The iron in solution was measured at intervals during the test, and the total iron in solution at the end of the test was compared to the weight loss. Generally in excess of 95% of the weight loss iron was found in solution. It was felt, therefore, that corrosion kinetics could be estimated from the iron counts. The test protocol was essentially identical to the one listed in Appendix I. Typically the corrosion rates were observed to drop within the first two or three hours to a steady state level which was very close to the average weight loss corrosion rate. Quoting the average corrosion rates for the 100 hour test period will therefore represent a realistic picture of the degree of inhibition which could be achieved at each pressure level with each inhibitor concentration.

The results are shown in Figure 3. The concentrations for Inhibitor B are given in active ingredients which are generally 50% by weight of the formulation.

Below 450 psi $CO_2$ partial pressure the corrosion rate increases with pressure at constant inhibitor concentration as expected. This is equivalent to saying the effective inhibitor concentration increases with $CO_2$ pressure. Above 450 psi the corrosion rate decreases with pressure, which mirrors the field experience. Whether the observed maximum is indeed at 450 psi is open to question since the test pressures were chosen arbitrarily and spaced fairly widely, but there is no doubt that a maximum exists. The range of pressures recorded along with the corrosion rates in the field varied from 250 psi to about 1800 psi with, however, only few data points below 450 psi. The multiple linear regression analysis did therefore show a negative pressure effect, with reduced significance (93%), because it could not account for the inherent non-linearity of the corrosion rate – pressure relationship.

## INHIBITOR DEVELOPMENT FOR THE POSTLE AREA

### 1. Background

In view of the facts, as known from the above and discussed in earlier studies, it was not immediately obvious whether the corrosion inhibitor used at the time across the Postle field was a) the best product available, b) used at the appropriate concentration and c) used in such a manner as to be transported to those areas in the production system where it was needed most.

The wells at Postle are to a large extent equipped with electrical submersible pumps in packerless completions (Fig. 4). The miscible pressure in the reservoir is about 3600 psi. Flowing bottom hole pressures are of the order of 2500 psi. However, the pressure at the pump intake depends on the fluid level maintained in the casing space for optimum pump efficiency and the flowline pressure (150 to 200 psi). The fluid level can vary from 500 to 2000 feet resulting in pump intake pressures from about 450 to 1100 psi[2)]. The pressure inside the production tubing above the pump is always of the order of 2000 to 2500 psi (corresponding approximately to the static pressure of the fluid column in the production tubing), and therefore higher than the pressure on the annular side. All gas not separated out in the gas separator upstream of the pump, will therefore most likely be in solution in the fluids in the tubing, at a concentration corresponding to the partial pressure prevailing on the casing side, or slightly higher[3)]. The flow regime in the tubing will be full liquid flow up to the point where the static pressure is lower than the bubble point pressure of $CO_2$. At that point gas will break out of solution and a three phase flow (gas, oil, water) will develop. As a consequence of this the mixture velocity will increase and can easily reach 3 fold the velocity of the liquid alone depending on the pump intake pressure; (the higher the fluid level the greater the pump intake pressure and the more gas dissolves in the liquids). The flow conditions in the tubing therefore change from the bottom to the top along with the chemical conditions in the liquid. Lower flow rates, higher temperatures and higher $CO_2$ concentrations prevail at the bottom while higher up in the production tubing the temperature and $CO_2$ partial pressure will be lower while the flow rate can be considerably higher. It is, under these conditions not a priori possible to predict the minimum effective inhibitor concentration.

A similar situation exists on the annular side and is even less accessible to prediction. The flow condition here will always be gas churning up the annulus through the fluid level forming a frothing liquid until the gas velocity is high enough to gas lift liquids from the casing space. At this time some

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[2)] these numbers are approximate because they also depend on the mixture density of the fluids in the annulus.

[3)] It appears that the downhole gas separators placed ahead of the pump intake have an efficiency of 80% and perhaps even higher.

sort of slug flow or eventually annular flow will develop. The flow intensity (shear stress) will depend on the gas flow rate up the annulus, which in turn depends on the pressure, hence the fluid level. In general one would expect again that the higher the pressure (fluid level) the lower the "flow intensity, but the greater the $CO_2$ partial pressure. Even though all these parameters can be calculated, their relationship to corrosion and corrosion inhibition has never been established and it is impossible in a situation of this kind to guess at the effective inhibitor concentration for those areas experiencing most severe corrosion conditions.

The chemical treatment of these wells consisted originally of weekly batch treatments into the annulus with an over-flush of produced fluids. As the $CO_2$ breakthrough occurred, continuous treatment facilities were installed. The corrosion inhibitor was injected continuously into the annulus with an over-flush of produced fluids. Because the turbulence at the well head could potentially carry some or all of the inhibited fluids into the gas flowline at surface, 40 ft injection capillaries were installed with the expectation that the injected fluids would bypass this turbulent zone and still fall to bottom. Later, some full length capillaries were installed in selected wells (Fig. 4) in order to mix the inhibitor into the produced fluids at the perforations and thereby protect the casing and liner below the pump intake. The estimate of the effective inhibitor concentration, which had been shown to be dependent on pressure and flow rate remained elusive however, and became the subject of the subsequent study.

## 2. Laboratory Evaluation of the Effective Inhibitor Concentration.

### Test Methodology and Preliminary Inhibitor Selection

For the purpose of determining optimum use concentrations for inhibitors in a situation where the $CO_2$ partial pressure, the flow rate and the water cut of the produced fluids can all change in wide limits, high speed autoclave rotating cage methodology (HSAT)was again chosen. This methodology has been described in numerous prior publications (Ref. 7. 8, 9, 10). The generalized test protocol is detailed in Appendix I. Since at Postle the concern was both with preventing corrosion of the production tubing as well as the casings, all representative metallurgies (J-55, N-80, L-80 and AISI-1018) were included. The rotating cage contained in general two J-55 coupons and one each of N-80 and L-80 cut from tubing sections received from the field. In order to assess the corrosion kinetics and to establish steady state corrosion rates continuous PAIR (LPR) measurements were made along with iron count studies. The build-up of iron in the test solution during the 120 hr test was monitored often enough to establish an adequate corrosion rate – time trend which could be compared with the PAIR – time trend and from which the steady state (final corrosion rate) could be extracted. The PAIR corrosion rate readings, however, were more difficult to interpret. The weight-loss corrosion rates of the AISI-1018 electrodes were many times (2 to 10 times) greater than the corrosion rates obtained by averaging the PAIR measurements over time[4) 5)]. It was therefore necessary to rely almost exclusively on the iron count kinetics. It was found that the steady state corrosion rate was generally established within a few hours of the start of the test and differed little from the average weight-loss corrosion rate, particularly in those situations where good inhibition was achieved.

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[4)] Averages were obtained by integrating the area under the corrosion rate-time curve and dividing the integral by the total time.

[5)] This effect was later also observed in the field and will be discussed in the following publication

Initially a fair number of inhibitors, selected for the purpose by experienced personnel in two supplier companies, were tested under the most severe conditions anticipated in the field [6] at 100 ppm each. The results ranged from zero protection all the way to about 90 or 95% protection.

**Table 3**

**Screening of Inhibitors at 100 ppm in the HSAT at 750 psi $CO_2$, 1500 rpm, 160 $^{O}F$, Averages of all Metals**

| Inhibitor | General Weight-loss mpy | Local Corrosion Rate mpy |
|---|---|---|
| C | 66.8 | 700 |
| D [7] | 243 | 1620 |
| E | 284 | 3000 |
| F | 73 | 2700 |
| G | 775 | 4400 |

On this basis Inhibitor C was selected for a detailed parametric study in an effort to determine the optimum effective concentration over a producing parameter range expected to prevail in the field.

**Test Matrix**

The test matrix for inhibitor C is shown in Fig. 5. The choice in rotational speed (500, 1000, and 1500 rpm) was somewhat arbitrary in that the most severe flow conditions had to be represented as well as milder ones, but not so low that the oil and water phases in the autoclave would not be properly mixed. It was verified that at 500 rpm good mixing still prevailed in the autoclave with, however, much lower shear stresses. The test pressures varied over a range which can be expected to prevail in the Postle wells. The water to oil ratio initially was chosen at 1.8 to be varied later. The test matrix was planned as a $2^2$ factorial design with a center point to facilitate assessment of non linearity in the resulting correlations.

The objective of the series was to evaluate the inhibitor concentration necessary to achieve a target corrosion rate, rather than determining the corrosion rate at a given inhibitor concentration. In order to do this it was necessary to perform several tests with different inhibitor concentrations at each of the five test conditions. It was hoped that the resulting performance curves (corrosion rate vs. inhibitor concentration) could be reasonably extrapolated to the desired target corrosion rates.

**Evaluation of the Results**

Figures 6 and 7 show typical performance curves for J-55 and L-80 steels. In a double logarithmic plot the relationship between performance (inhibited average weight loss corrosion rate and/or final corrosion rate from iron counts) and inhibitor concentration turned out to be linear. Within experimental error this was also true for the steady-state corrosion rates. Within experimental error the steady-state corrosion rates (from iron counts) varied only little from the average weight loss rates as one would expect in

[6] At this stage the judgement whether the most severe laboratory conditions also represented the most severe field conditions was obviously intuitive and solely based on qualitative prior experience.
[7] Inhibitor previously used in field at concentration of less than 100 ppm

inhibited systems. The correlation equations, which are only shown for the average weight loss in Fig. 6 and 7, are a tool to calculate the corrosion rate for any inhibitor concentration. For the purpose of developing the model, however, the inhibitor concentrations for the target corrosion rates of 1, 2, and 4 mpy were extrapolated manually from the graphs for the steady-state corrosion rate curves. The results are summarized in Table 4.

**Interpretation or the Results**

An overview of Table 4 quickly shows that not all metals are inhibited equally. In particular the L-80 metallurgy proved less susceptible to corrosion inhibition, a fact which had also been observed consistently during the screening tests for all compounds tested. It is further observed that the differences in inhibition efficiency on different metals becomes more pronounced as the corrosion conditions become more severe.

In order to obtain a better overview of the relationship between the severity of corrosion (combination of $CO_2$ partial pressure and velocity) response surface methodology[8)] was used. Specifically, as shown in Fig. 8 and 9, "iso-corrosion-inhibitor-concentration" lines were generated in a grid of $CO_2$ partial pressure vs. rotating velocity of the cage. From Figure 8 one can conclude that for J-55 the major effect which controls the effective inhibitor concentration is the velocity (rpm) or by implication the shear stress. Only at higher shear stress does pressure begin to play a role in increasing the effective concentration. In comparison, L-80 (Fig. 9) is clearly more difficult to inhibit and pressure appears to have a more pronounced effect. The contours for N-80 are between those of J-55 and L-80. The mild steel, AISI-1018, performed in almost the same manner to the J-55, even though the PAIR electrodes were stationary. It is assumed that the rotating agitation of the liquid in the autoclave generates similar shear stress as experienced by the rotating cage. This point is important later when laboratory data will be compared to field data.

### 3. Localized Corrosion

As is well known, high fluid velocities in $CO_2$ environments cause flow induced localized corrosion, and it is also known that inhibition of FILC requires high inhibitor concentrations. As indicated in Appendix I, the maximum local penetration rates were routinely measured using a standard microscopic technique. Figures 10 and 11 show the pitting rates as a function of the general weight loss corrosion rates for J-55 and L-80. The trend-lines for both metals are similar in that the pitting rate is not proportional to the general corrosion rate (in inhibited solutions). Of greater importance, however, is the fact that pitting inhibition on J-55 occurs below 2 mpy general corrosion rate, while for L-80 much lower corrosion rates (< 1mpy) are required for reliable inhibition of pitting. N-80, while more easily inhibited than L-80, has shown a greater tendency toward localized corrosion. This reversal in behavior may need further study relative to metallurgy and compositional parameters, but seems to be in general agreement with earlier studies.

An alternate way of evaluating the above data consists of a multiple linear regression analysis. For J-55, the following equation was obtained:

$$(\text{Inhib. Conc.})_{1\ \text{mpy}} = -117.1 + 0.105\text{x}(CO_2\ \text{partial pressure}) + 0.228\text{x}(\text{rpm}) \qquad (2)$$

[8)] Software: JMP 3.2 Prof. Ed. 1997, SAS Institute, Inc., Cary, NC, USA

This equation, which does not account for any non-linearity in the system, holds only within the experimental parameter range and can obviously not be extrapolated to milder corrosive conditions since negative inhibitor concentrations would result. Never the less, if the problem of the relationship of shear stress on the rotating cage and shear stress in the production tubing can be resolved, the above equation begins to offer a first approximation prediction of the inhibitor concentration which may have to be used under prevailing conditions in the field.

**4. The Effect of the Water/Oil ratio on Corrosion Inhibition**

In addition to flowrate and $CO_2$ partial pressure, the water to oil ratio in the produced fluids was expected to be a major parameter in influencing the effective concentration. Table 5 summarizes the results. The general trend in the data indicates that an increasing water/oil ratio increases the corrosion rate at both velocity conditions with the exception of the two data points at 225 ppm inhibitor where the trend is reversed. The discrepancy is small and possibly, at the low corrosion rates, within experimental error. A linear regression analysis resulted in the following equation:

$$(\text{corr. rate})_{750\text{psi, J-55}} = 1.4 + 0.00815\text{x(rpm)} + 0.480\text{x(Water/Oil)} - 0.0616\text{x(Inhibitor)} \quad (3)$$

which allows one to evaluate qualitatively the trends of the water/oil ratio and the effectiveness of the inhibitor as a function of velocity. Figure 12 shows how the corrosion rate increases with water/oil ratio. At the 100 ppm level of inhibitor, for example, increasing the water/oil ratio from 2 to 8 can move the corrosion of J-55 from non- pitting to a pitting situation, particularly at high rpm levels.

Similarly, one can see from Figure 13 how the inhibitor concentration may have to be increased at a given water/oil ratio in order to move from a pitting situation (corr. rate >2 mpy) to one where no pitting occurs.

Inhibitor C in these studies behaved differently from Inhibitor B discussed earlier on the basis of field data for this inhibitor. The differences in the two inhibitors is seen in their respective dispersibilities. Inhibitor B was essentially totally oil soluble and formulated only with a wetting agent to facilitate "filming" from the oil phase without resulting in water dispersibility. Inhibitor C on the other hand was formulated with the aid of dispersants. Since inhibitor dosage is always assessed on the basis of total produced fluids, high water dispersibility causes a reduction of the inhibitor concentration in the water as the water cut increases. Hence the observed effect for inhibitor C was not unexpected.

## DISCUSSION AND SUMMARY

The purpose of a corrosion inhibitor program is to reduce failures, and the effective inhibitor concentration to do this must be capable of inhibiting corrosion under the most aggressive conditions. In order to achieve those objectives one must have 2 models. The first model must describe quantitatively the environmental and the flow conditions (including those pertaining in annular spaces and across upsets such as tubing collars), and the second model must relate the effective inhibitor concentration to the parameter values obtained from the first model (local shear stress, temperature, partial pressure and water/oil ratio).

This study, an early attempt to quantify such relationships, has demonstrated a complex interplay between the effective inhibitor concentration (concentration to achieve a target corrosion rate) and the systems parameters. Helpful in this endeavor was the fact that the inhibitor performance curve could easily be linearized in a log (corr. rate) vs. log (inhib. conc.) plot. Correlations were attempted between the effective inhibitor concentration and flow rate (rpm), $CO_2$ partial pressure, and the water/oil ratio. The correlations were expressed either by means of surface response methodology or regression equations. The latter have predictive value within the experimental parameter range.

It was found that both increasing flow rate and pressure call for increased inhibitor concentration if target corrosion rates are to be achieved. In the case of inhibitor C, increased water/oil ratio also calls for increased inhibitor concentration.

However, it was also shown, in agreement with earlier studies, that the pressure relationship may be very complex and that the water/oil ratio effect depends on the nature of the inhibitor. The oil soluble inhibitors A and B showed the opposite behavior from inhibitor C with respect to the oil/water ratio. The fact that it is possible to formulate inhibitors such that they become more effective as the water/oil ratio increases, an effect not heretofore recognized as such, should open up new avenues of both inhibitor synthesis as well as formulation.

The missing links between modeling corrosion inhibition in the lab and application in the field are twofold:

- verification of the lab results in the field
- translation of the shear stress from the cage to the tubulars.

Both these issues will be dealt with in the follow up publication. ( Ref.11)

The above correlations were expressed in terms of steady state corrosion. Of greater interest, however, is localized corrosion, particular in $CO_2$ environments at high flow rates (FILC). Detailed and extensive pitting measurements indicated that under test conditions general corrosion rates have to be reduced to below a certain level to prevent localized corrosion as well. In the case of J-55, this level is about 2 mpy. In the case of L-80 and N-80 it is below 1 mpy. How this correlation will hold up in the field is yet to be shown, however, there has long been a feeling in the industry that general corrosion rates should be inhibited below 1 mpy (preferably 0.5 mpy) to prevent local attack.

A final word about economics. From the above it becomes clear that corrosion inhibition in high pressure, high flow rate, high water cut systems becomes very expensive in terms of ¢/bbl of oil produced unless either improved inhibitors are developed, or producers make an effort to combat corrosion in those areas most difficult to inhibit by other means, an effort which is well underway in many instances.

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Development of a Corrosion Inhibition Model: II Verification of Model by Continuous Downhole Corrosion Rate Measurements under Flowing Conditions with a Novel Tool. NACE, CORROSION/99, paper 99003.

## APPENDIX I

### Test Protocol for Laboratory Testing in the HSACT
### Postle Diagnostic Inhibitor Evaluations

**I. Test Conditions**

- Autoclave: 4 L
- Liquid Charge
  - Brine 1.83 L
  - Hydrocarbon [1] 1.00 L
- Temperature 160 °F
- Pressure variable from 100, 425, 750, and1500 psi (at test temperature)
- Gas Composition
  - $CO_2$ 100 %
  - $H_2S$ 500 ppm $H_2S$ in $CO_2$[2]
- Stirring Rate variable (500, 1000, and 1500rpm)
- Test Duration 5 days
- Synthetic Brine [3]

| | | | |
|---|---|---|---|
| NaCl | 93.1 g/L | $CL^-$ | 70,000 mg/L |
| $CaCl_2.2H_2O$ | 22.0 g/L | $Ca^{2++}$ | 6,000 mg/L |
| $MgCl_2.6H_2O$ | 8.4 g/L | $Mg^{2++}$ | 1,000 mg/L |
| TDS | 113,900 mg/L | | |

- Coupons 4 PAIR electrodes
  - Cage 2 x J-55, N-80, L-80, (Coupon area 30 $cm^2$ per coupon)
  - Electrodes 4 std PAIR electrodes (Electrode are 9 $cm^2$ per electrode)

**II. Coupon Preparation**

- Sandblast coupons with 80 grit silicon carbide
- Degrease coupons by
  1. Using an ultrasonic bath: wash coupons in 50/50 xylene/isopropanol mixture for 5 minutes
  2. Rinse in isopropanol
  3. Rinse in acetone
  4. Dry with nitrogen
- Weigh to 0.1 mg

**III. Test Procedure**

- Install coupons in rotating cage on stirring shaft
- Install PAIR electrodes on autoclave head
- Add 1000 ml Isopar M to autoclave
- Add 1830 ml of brine to autoclave
- Sparge fluids in autoclave with nitrogen for 30 minutes (prior to closing autoclave)
- Inject inhibitor as needed
- Add 200 ppm of bicarbonate based on brine volume (0.504 gm $NaHCO_3$)
- Assemble and close-up autoclave

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[1] Isopar M™ (a paraffinic hydrocarbon available from EXXON Corp.)

[2] the $H_2S$ concentration in the $CO_2$ charge gas was designed to result in about 150 ppm $H_2S$ in the gas under test conditions. This level was the maximum encountered in the field. The concentration in the gas under test conditions is only slightly dependent on total pressure with constant temperature.

[3] Note: bicarbonate is added directly to the autoclave in order to avoid precipitation of $CaCO_3$

- Begin data logging of PAIR corrosion data and other test parameters
- Deoxygenate fluids be repeating the following steps 5 times:
  1. Turn stirrer on at 1500 rpm
  2. Charge nitrogen to 1000 psi
  3. Mix fluids and gases for 3 minutes
  4. Turn stirrer to 200 rpm
  5. Slowly vent nitrogen to atmosphere
- Set stirring rate to 1500 rpm
- Charge test gas to charging pressure[4)] and verify equilibration (> 1 psi loss in 10 minutes)
- Heat to test temperature (160 $^{O}$F)
- Sample test solution and stabilize with HCl for iron count measurements
  1. When autoclave reaches test temperature
  2. 2 hours after sample #1
  3. every 24 hours (Note: these will be skipped over weekends)
  4. 24 hrs before end of test
  5. at end of test.
- Run test for total of 120 hrs
- Turn of heat
- Vent gases
- Turn off stirrer
- Open autoclave
- Remove and dry coupons
- Disassemble and clean autoclave. The cleaning procedure will include the dissambly and cleaning of the inside of the magnetic stirrer. All residual iron carbonate is to be removed completely.

## IV. Coupon Cleaning Procedure

- Clean coupons in inhibited acid solution (standard procedure)
- Rinse and dry coupons
- Weigh to 0.1 mg
- Calculate weight loss and corrosion rate

## V. Evaluation of Results

- **PAIR Probes**
  1. Determine weight loss as above
  2. Print out PAIR data
  3. Integrate under PAIR/time curve
  4. Compare PAIR corrosion rate to weight loss

- **Rotating Cage Coupons**
  1. Determine weight loss as above
  2. Determine pit depth using microscope
  3. Coupons will be photographed to maintain visual record of the corrosion damage

- **Iron Counts**
  1. Measure ppm iron using HACH Ferrover method
  2. Calculate corrosion rates based on differential iron concentrations to obtain corrosion kinetics
  3. Compare corrosion rate from total iron count to weight loss corrosion rate

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[4)] The charge pressure is lower than the target pressure at test temperature. A special model was used to determine the exact charge pressure (Ref. 9)

Table 4

**I. Inhibitor Concentrations for 1 mpy Target Corrosion Rate**

| Pressure | Rpm | J-55 | N-80 | L-80 | AISI-1018 |
|---|---|---|---|---|---|
| 750 | 500 | 40 | 50 | 55 | 25 |
| 425 | 1000 | 160 | 150 | 180 | 120 |
| 100 | 500 | 42 | 60 | 52 | 37 |
| 100 | 1500 | 200 | 200 | 200 | 150 |
| 750 | 1500 | 339 | 400 | 841 | 400 |

**II. Inhibitor Concentrations for 2 mpy Target Corrosion Rate**

| Pressure | Rpm | J-55 | N-80 | L-80 | AISI-1018 |
|---|---|---|---|---|---|
| 750 | 500 | 34 | 40 | 46 | 28 |
| 425 | 1000 | 140 | 130 | 170 | 80 |
| 100 | 500 | 30 | 54 | 46 | 30 |
| 100 | 1500 | 150 | 170 | 170 | 100 |
| 750 | 1500 | 248 | 309 | 646 | 251 |

**III. Inhibitor Concentrations for 4 mpy Target Corrosion Rate**

| Pressure | Rpm | J-55 | N-80 | L-80 | AISI-1018 |
|---|---|---|---|---|---|
| 750 | 500 | 24 | 28 | 32 | 20 |
| 425 | 1000 | 110 | 105 | 140 | 52 |
| 100 | 500 | 20 | 48 | 42 | 20 |
| 100 | 1500 | 100 | 150 | 150 | 75 |
| 750 | 1500 | 180 | 240 | 487 | 160 |

## Table 5

Final [Fe] Corrosion Rate Data for Different Metals as a Function of the **Water/Oil Ratio**, the **Rotational Velocity** of the Cage and the **Inhibitor Concentration** for Inhibitor C at 750 psi $CO_2$ Partial Pressure

| Run # | Water/Oil Ratio | Inhibitor Conc. ppm | General Corrosion Rates for different Metals | | | |
|---|---|---|---|---|---|---|
| | | | J-55 | N-80 | L-80 | AISI-1018 |
| **A. Low Velocity (500 rpm)** | | | | | | |
| 21 | - | 50 | *0.99* | *0.99* | *1.7* | *0.66* |
| 22 | + | 50 | *8.8* | *8.6* | *11.5* | *1.25* |
| 15 | - | 100 | *0.28* | *1.69* | *0.44* | *0.36* |
| 24 | + | 100 | *3.75* | | | *1.2* |
| **B. High Velocity (1500 rpm)** | | | | | | |
| 12 | - | 150 | *4.9* | *11.67* | *51.4* | *2.1* |
| 25 | + | 150 | *9.2* | | | *11..3* |
| 13 | - | 225 | *3.2* | *5* | *33* | *5.64* |
| 23 | + | 225 | *1.4* | *1* | *1.1* | *1.1* |

<u>**Oil/Water Ratio:**</u> - equals **1.83** + equals **9**

**Figure 1:** Inhibited Corrosion Rates as Function of Superficial Gas and Liquid Velocities from Little Creek Correlation of Coupon Data

Inhibitor A, Water/Oil = 117, Pressure 1800 psi

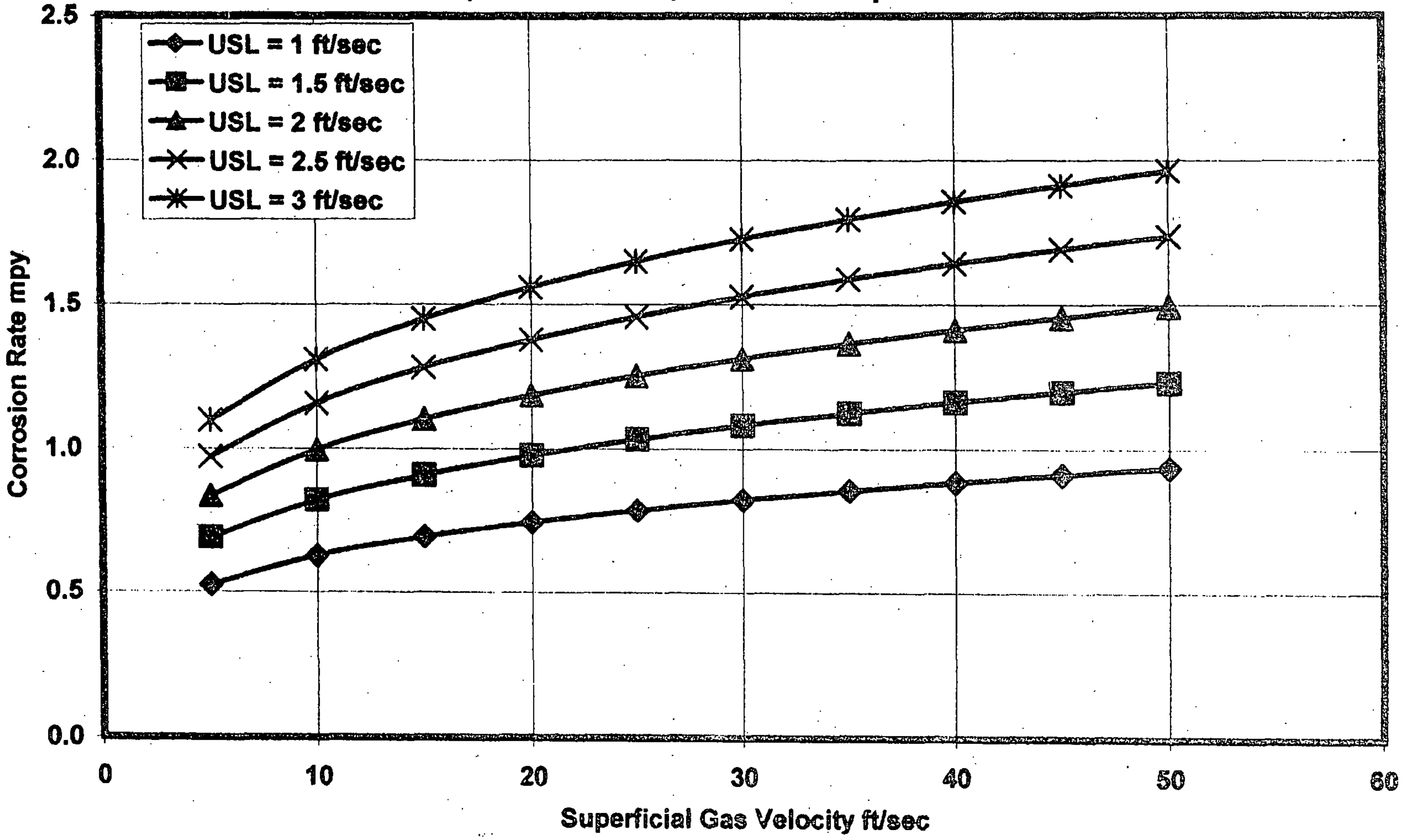


**Figure 2: Corrosion Rate as Function of Pressure and Water/Oil Ratio based on Little Creek Correlation of Coupon Data**

**Inhibitor A, $U_{SL}$ = 2 ft/sec, $U_{SG}$ = 2 ft/sec**

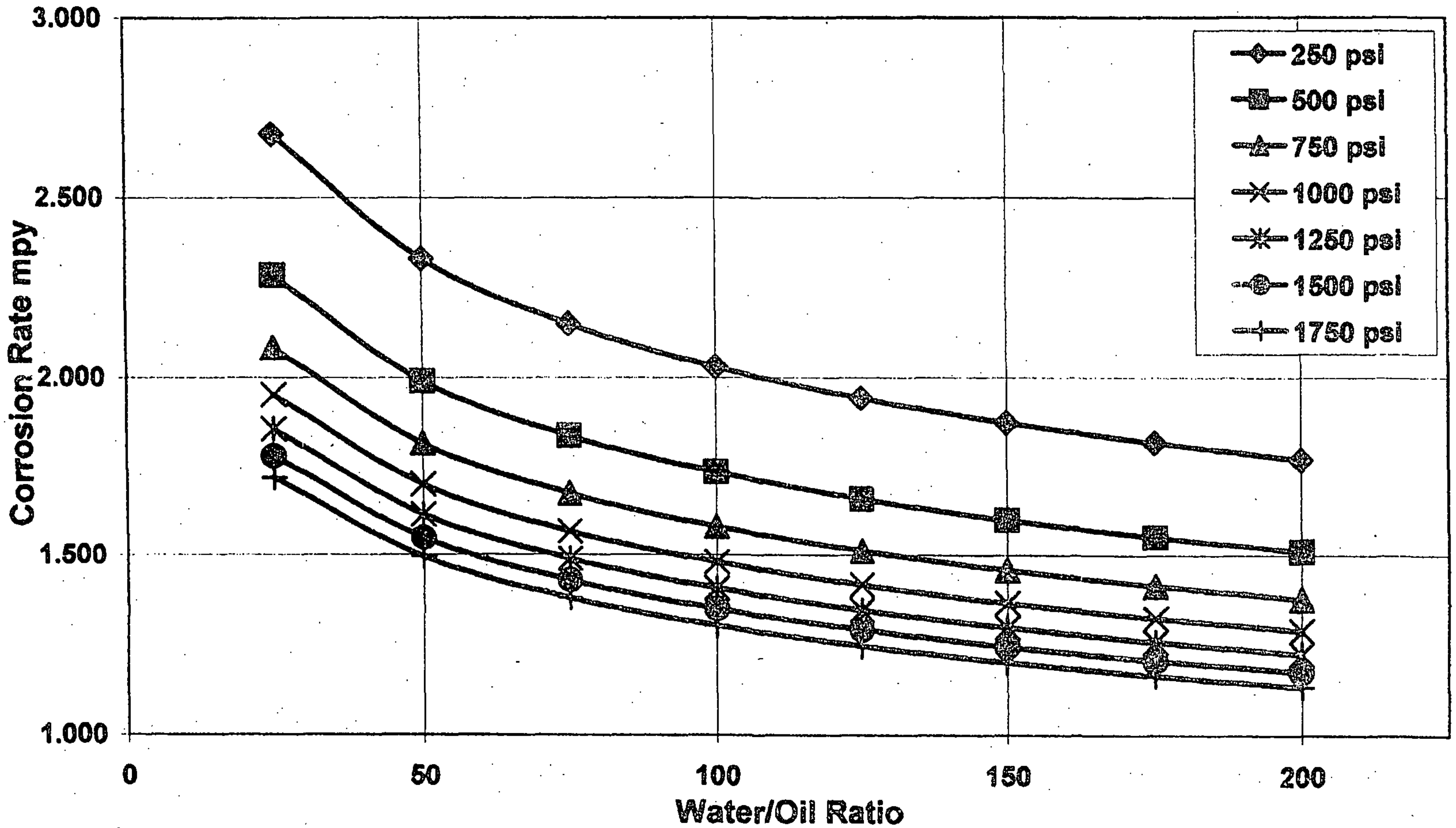
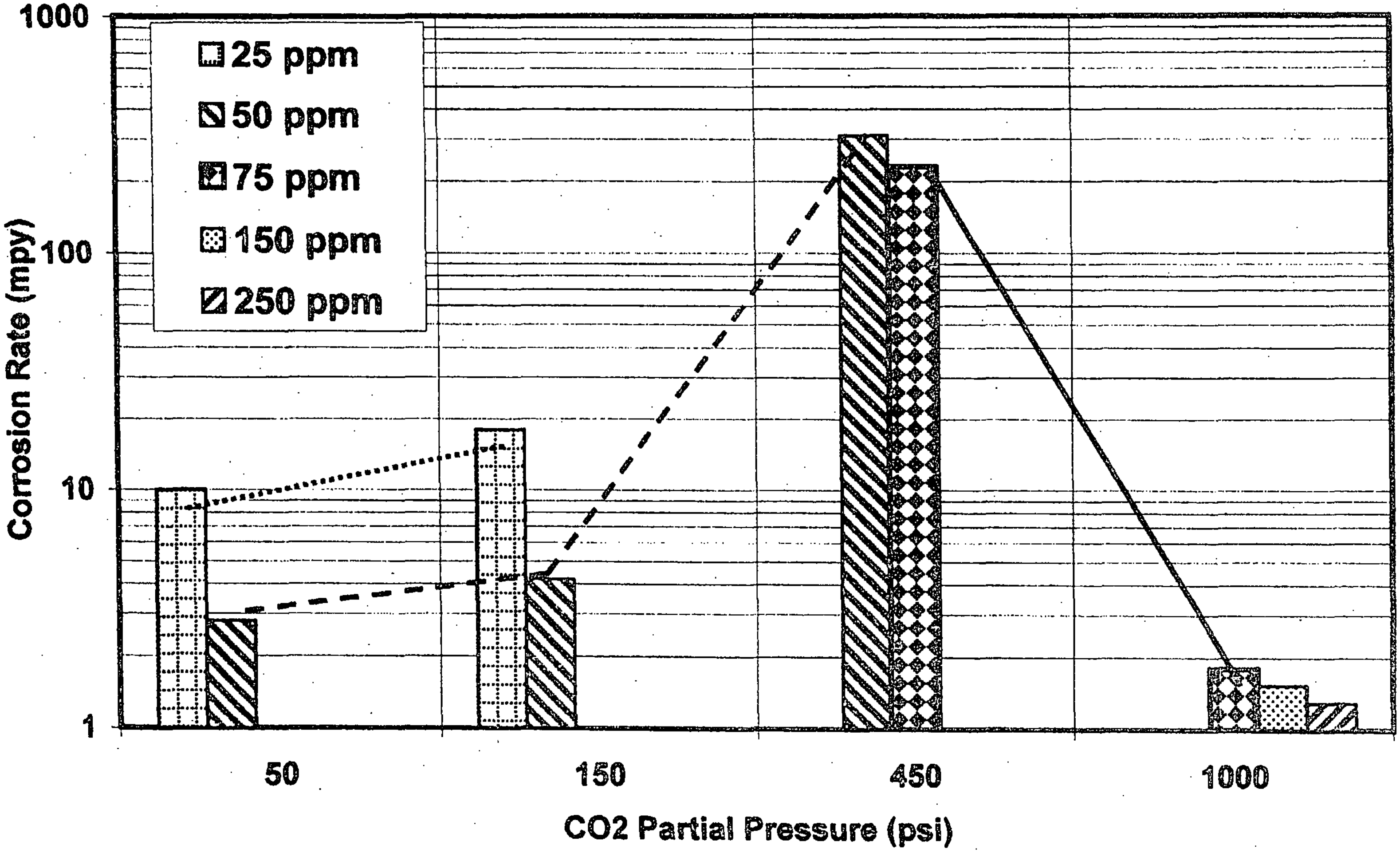


**Figure 3**: Inhibited Corrosion Rate as Function of CO2 Pressure (High Speed Autoclave Test)



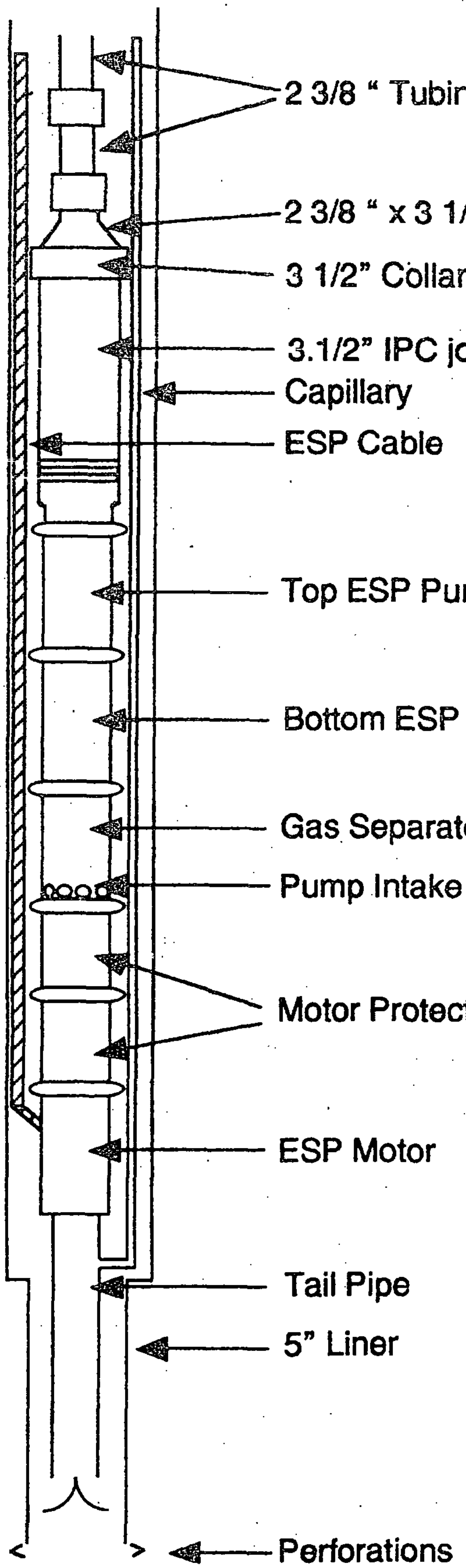



***Figure 4***

**Typical Completion of Producing Well in $CO_2$ Flood with full length Capillary**

| | |
|---|---|
| Perforations | approx 6150 ft |
| Bottom of Motor | approx. 6000 ft |
| Tail Pipe | approx. 100 ft |

Figure 5

**Evaluation of Inhibitor C at Different Concentrations and Test Conditions in the HSAT [Water/Hcbn Ratio = 1800/1000 (9:5)]**

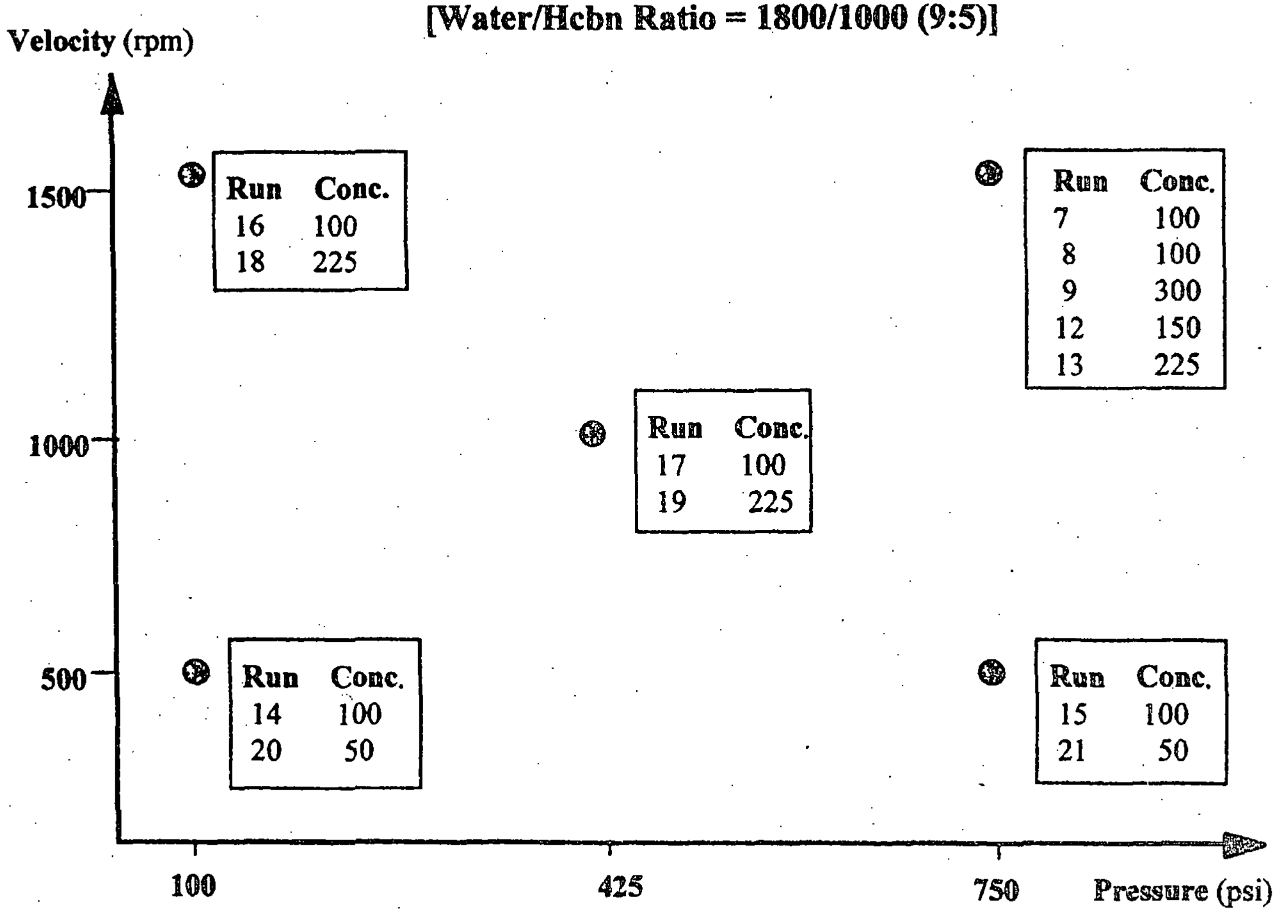


**Figure 6**: Inhibited Corrosion Rates of J-55 at 750 psi and 1500 rpm

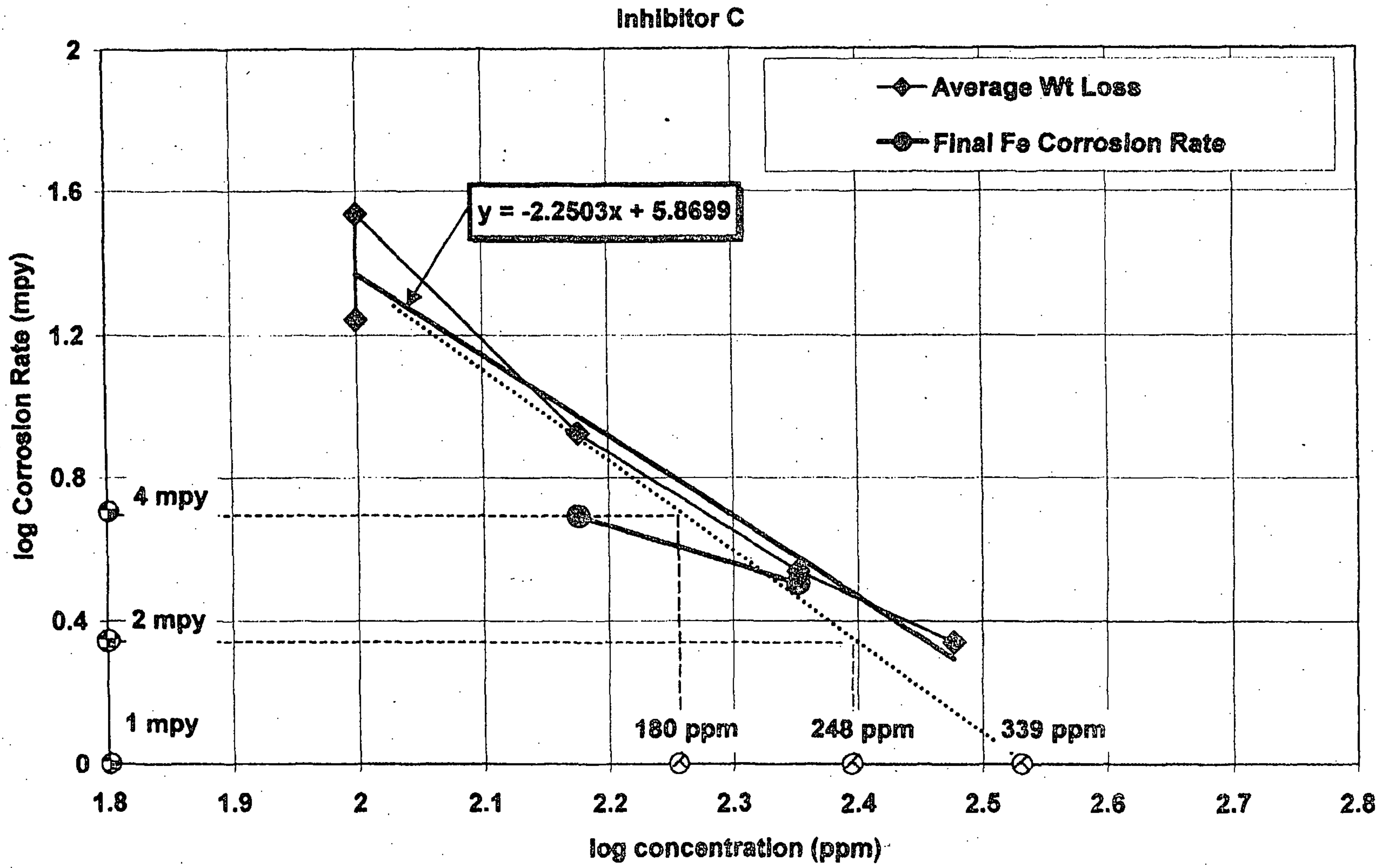
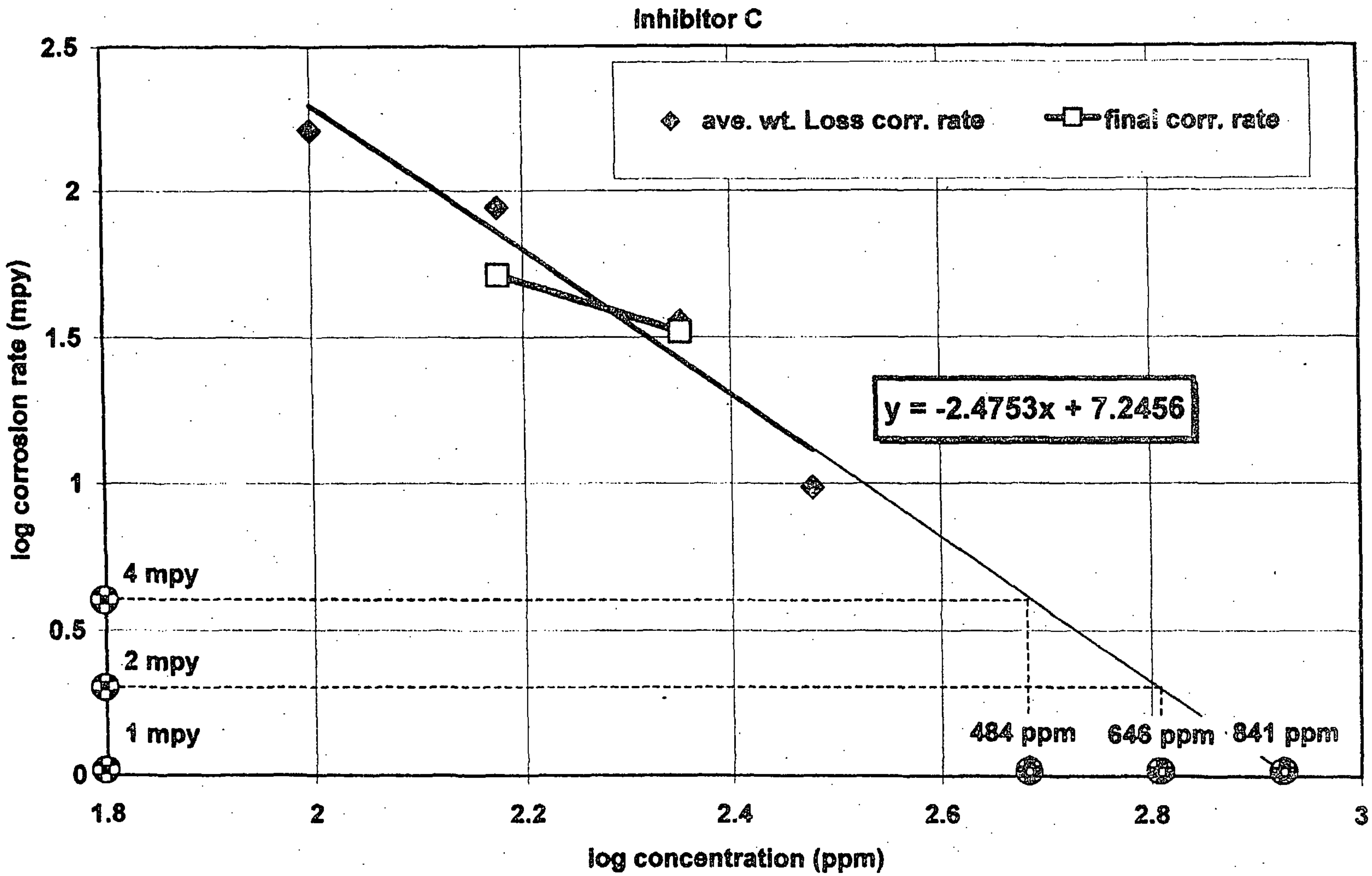


**Figure 7**: Inhibited Corrosion Rates of L-80 at 750 psi 1500 rpm



## Figure 8: Contour Plot for J-55
## Inhibitor Concentrations Necessary to Achieve 1 mpy Based on Final Corrosion Rates from Differential Iron Counts

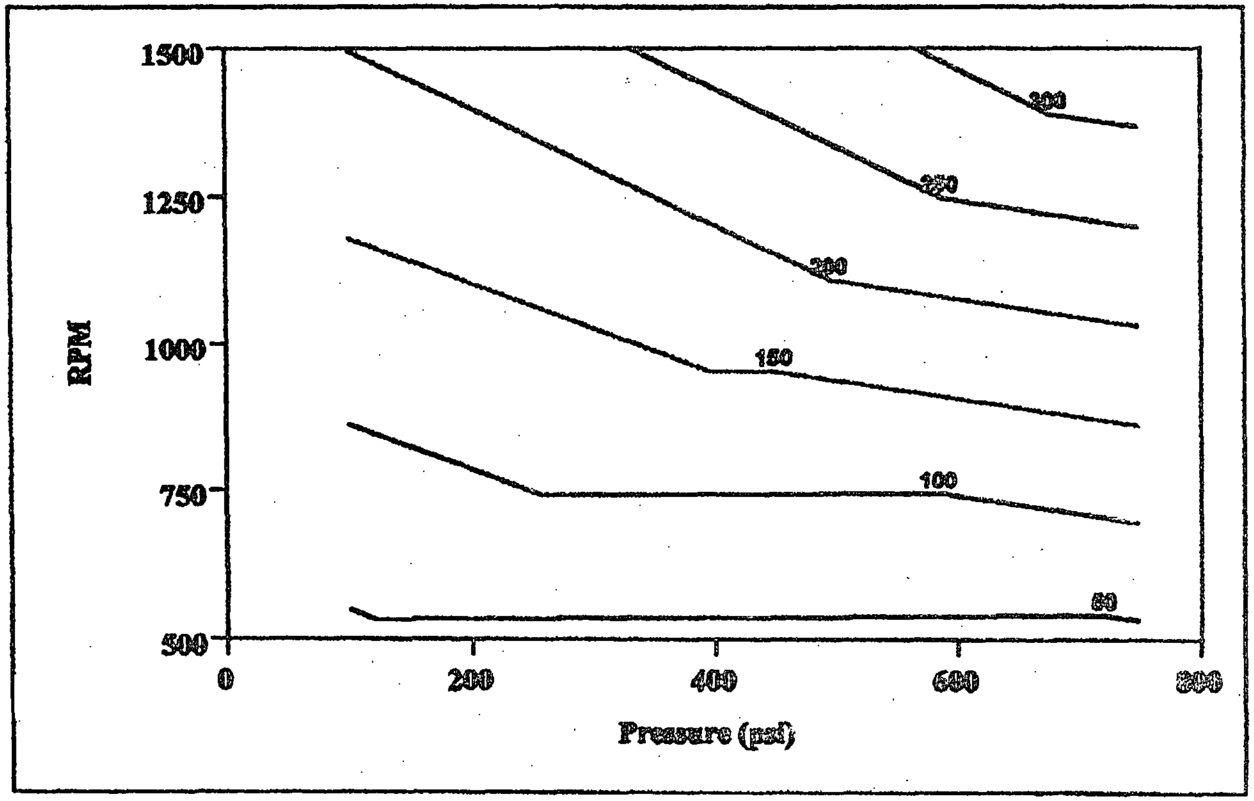


**Figure 9: Contour Plot for L-80**
**Inhibitor Concentrations Necessary to Achieve 1 mpy based on Final Corrosion Rates from Differential Iron Counts**

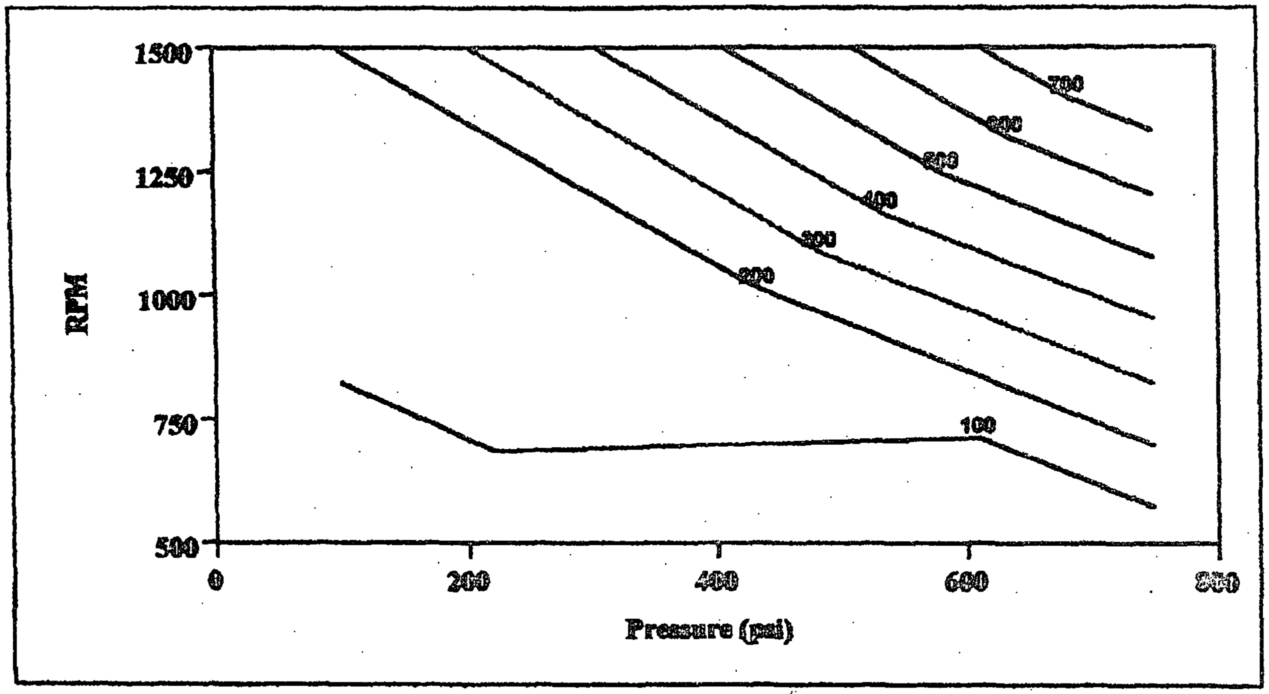


**Figure 10**: J-55 Pitting rate vs. Corrosion Rate

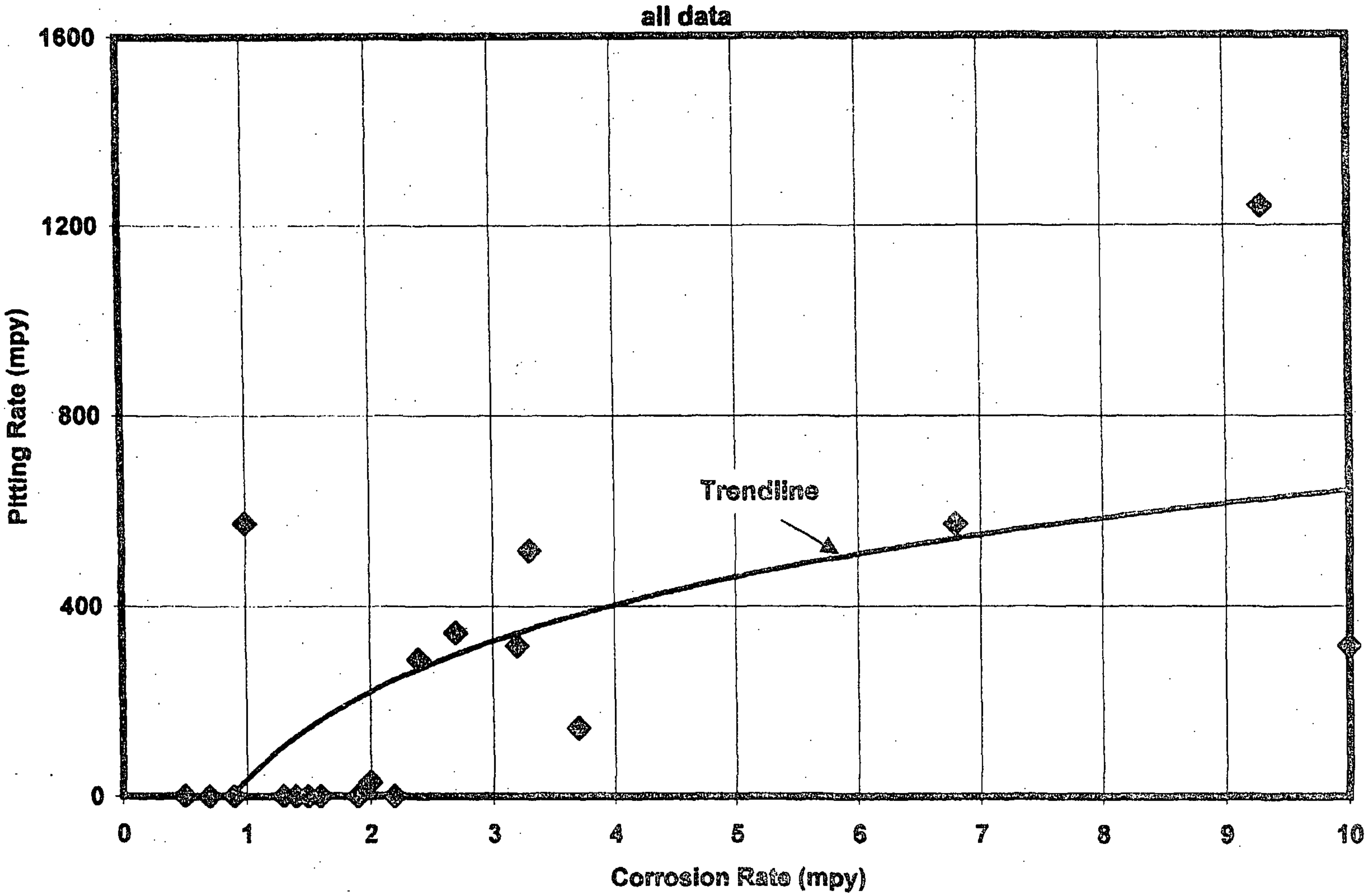
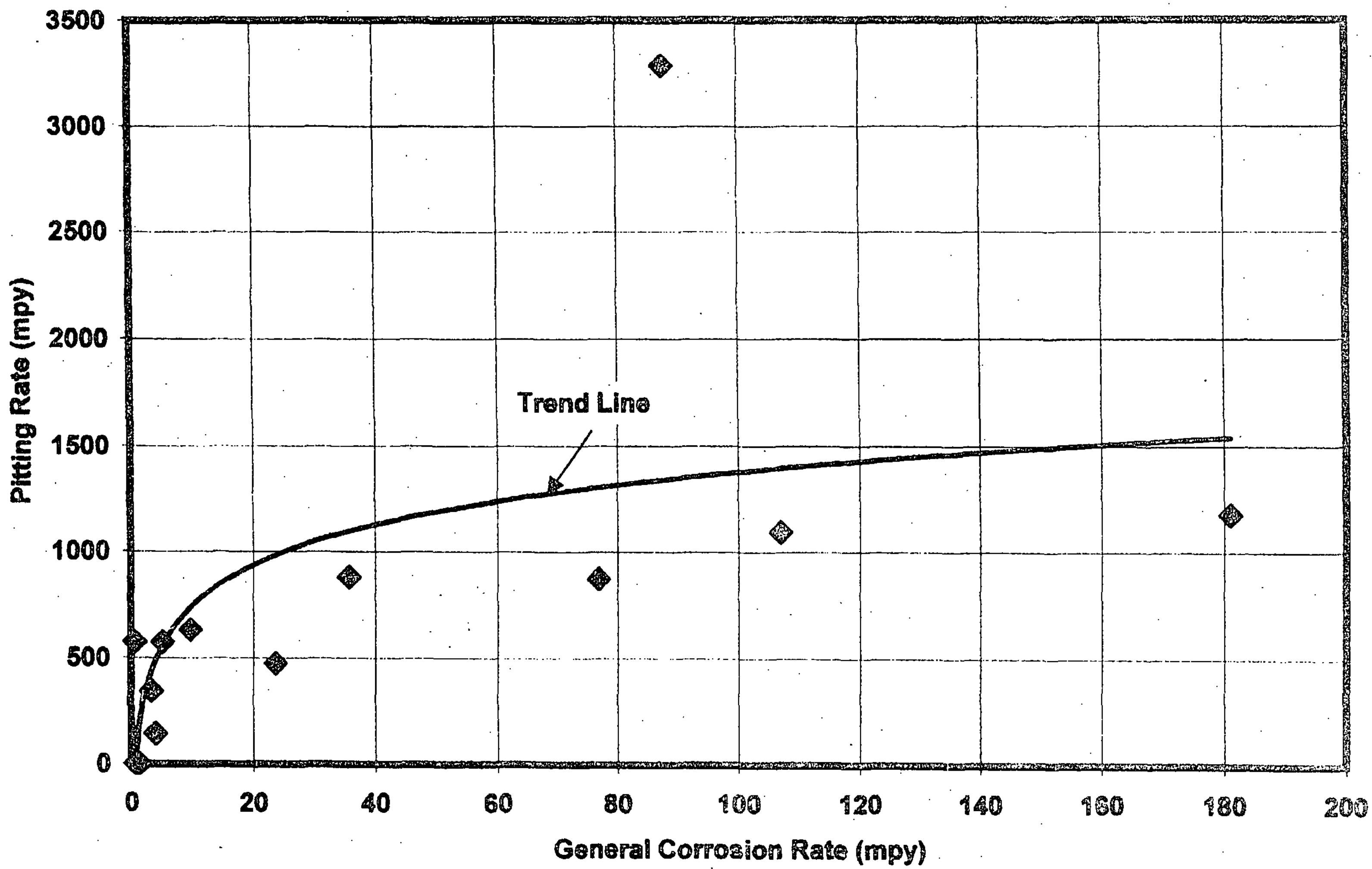
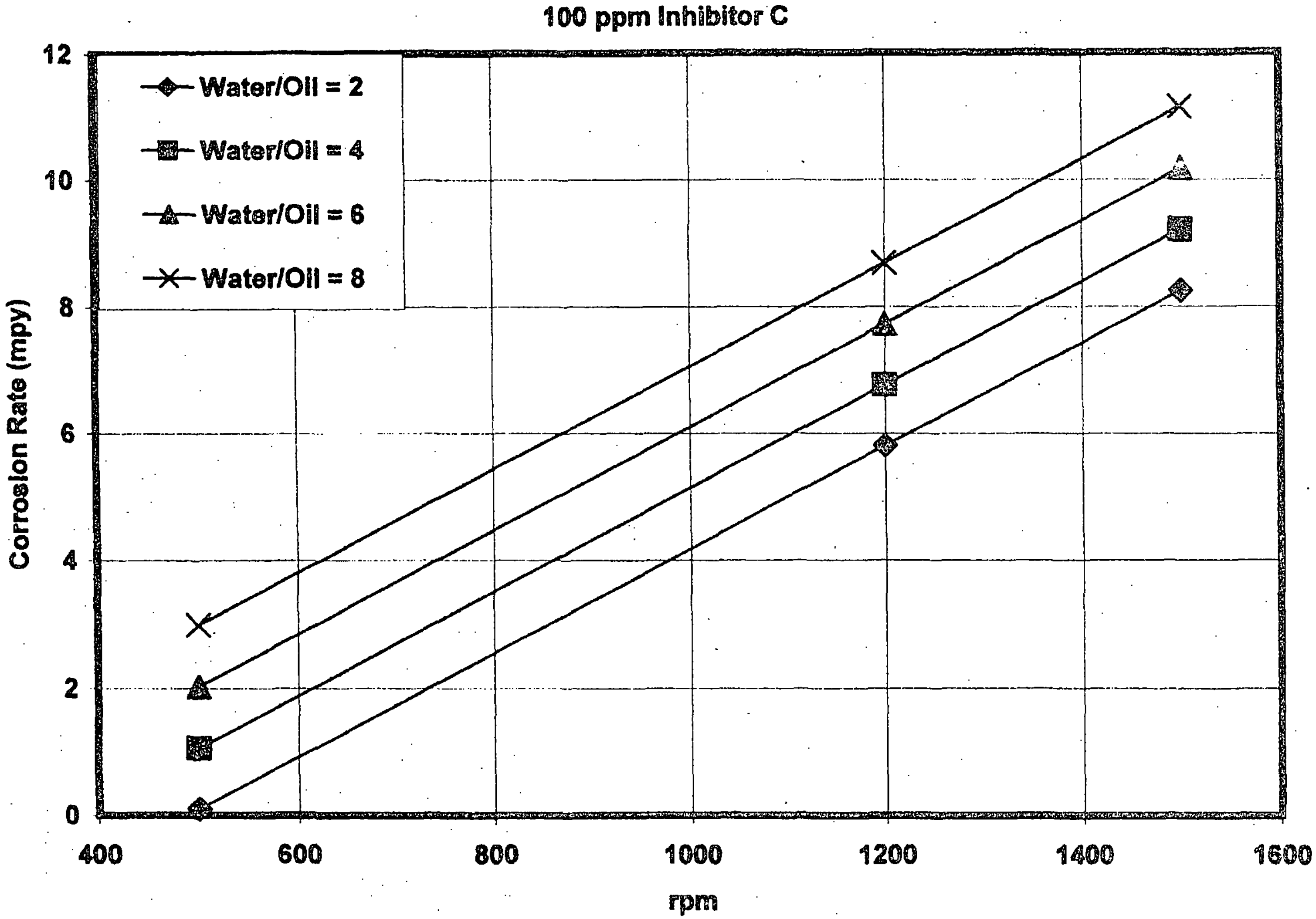


**Figure 11: L-80 Pitting Rates vs. Corrosion Rates**

all data

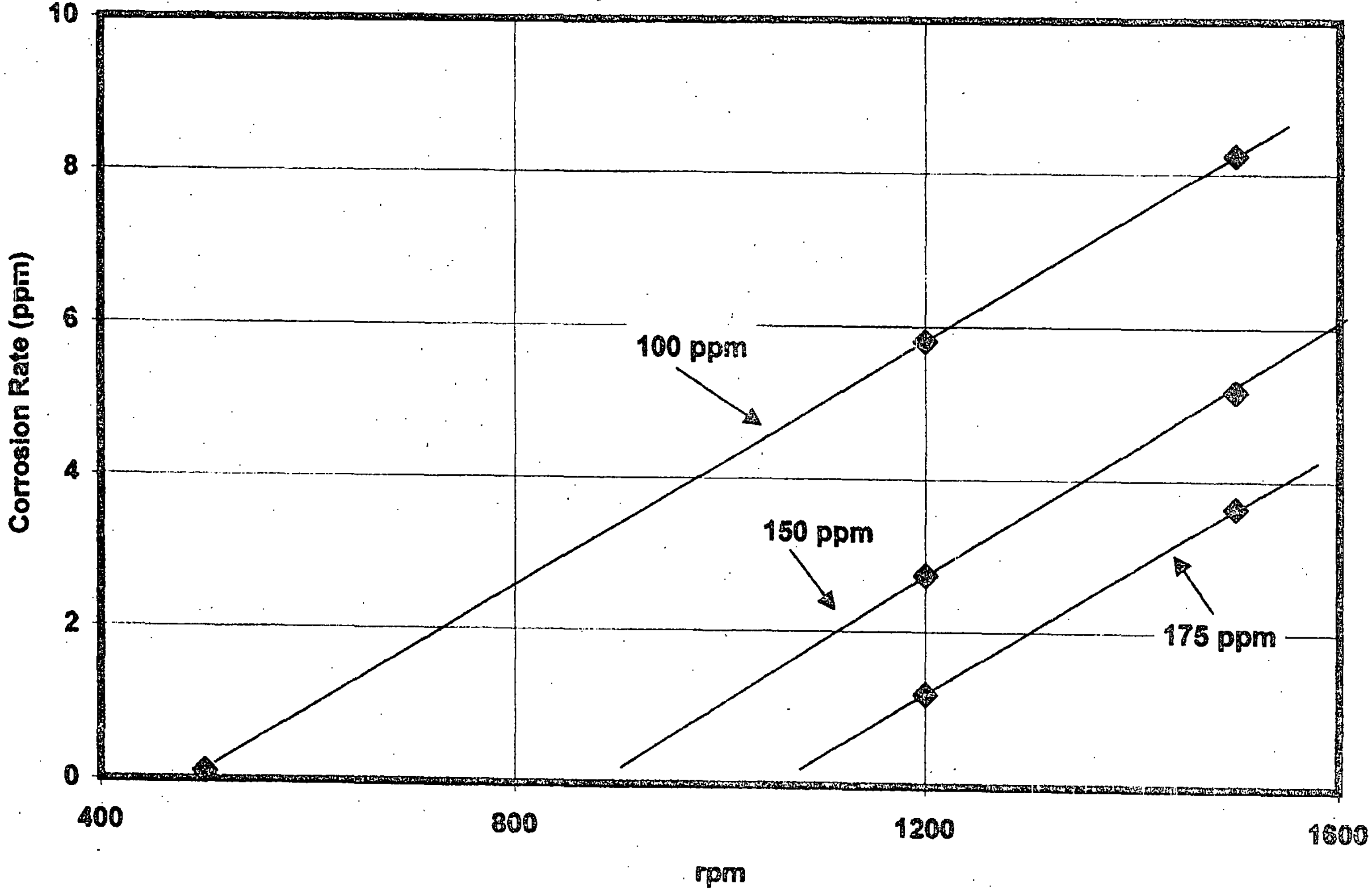


**<u>Figure 12</u>: Corrosion Rate vs. Velocity at 750 psi $CO_2$ Pressure**



**<u>Figure 13</u>: Effect of Inhibitor Concentration**

Inhibitor C, 750 psi $CO_2$, Water/Oil Ratio = 2



Paper No.
3

CORROSION99

# Development of a Corrosion Inhibition Model
# II. Verification of Model by Continuous Corrosion Rate Measurements Under flowing Conditions with a Novel Downhole Tool

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## ABSTRACT

A novel downhole corrosion monitoring system was used to monitor corrosion rates, and verify corrosion inhibitor effectiveness in the production tubing of a $CO_2$ flood in the Oklahoma panhandle. The monitoring system was placed in the first tubing joint immediately above the electrical

submersible pump. This location was deemed most corrosive, and therefore requiring the highest inhibitor concentration, due to high $CO_2$ partial pressure, the elevated temperature, and the extremely turbulent flow. Laboratory evaluations had indicated the approximate effective inhibitor concentration required to attain the desired target corrosion rate under similar environmental and turbulence conditions. The complex problem of translating laboratory flow (high speed autoclave test) to field conditions was attempted empirically using established correlation for the rotating cylinder and tubular flow.

Keywords: target corrosion rate, effective inhibitor concentration, shear stress, high speed autoclave test, $CO_2$ partial pressure, corrosion inhibition modeling, response surface methodology,

## INTRODUCTION

The Postle Field, situated in the Oklahoma Panhandle, north of the city of Guymon, has been in operation since 1958. The field produces form the Morrow Sand at a depth of 6,100 ft and was placed on $CO_2$ flood in 1995. The field differs from Mobil's other $CO_2$ flood operations in that it is a sandstone formation, while most of Mobil's West Texas $CO_2$ flood operations to date have been in limestones.

Initial corrosion control treatment for the Postle followed the program which had been developed for the West Texas limestone floods with a weekly batch treatment into the annulus at a rate of 20 to 25 ppm for inhibitor D[1)]. The treatment procedure was changed from batch treatment (inhibitor with overflush) to continuous when $CO_2$ breakthrough occurred, but without changing the treatment rate.

Shortly after $CO_2$ breakthrough occurred the field began to require more frequent well workovers. Severe corrosion on both internal and external surfaces of the production tubing was found with corrosion rates, in some instances being in excess of 300 mpy. Field personnel observed that high corrosion rates appeared to be associated only with wells where large quantities of $CO_2$ would be produced though the corrosion pattern was complex and initially difficult to predict.

The Postle $CO_2$ flood, being a sandstone formation, is inherently more corrosive than "limestone floods" mainly because of the low bicarbonate concentration (200ppm) in the produced water from sandstone formations (vs. 2000 ppm bicarbonate from limestone formations), and the attendant lower pH that results in the presence of $CO_2$.

Table 1 shows the influence of bicarbonate ion on the pH of a $CO_2$ containing water. The difference between 200 and 2000ppm bicarbonate in the produced brine is one between the formation of an insoluble, protective iron carbonate film on the surface of the metal at higher pH and the absence thereof at the lower pH.

---

[1)] Some performance data for this inhibitor are given in Ref.4

**Table 1**
pH in Produced water as Function of $CO_2$ Partial Pressure and Bicarbonate concentration
(Temperature 160 °F, Ref. 1).

| $P_{CO2}$ psi | $HCO_3^-$ | |
|---|---|---|
| | **200 ppm** | **2000 ppm** |
| **100** | *4.87* | *5.87* |
| **500** | *4.18* | 5.17 |
| **1000** | *3.89* | 4.87 |

It has also been shown that commercial inhibitors differ in their ability to inhibit at high and low pH's (Ref 2). In addition, higher flow rates and higher water cuts greatly aggravate corrosion at the lower pH due to increased mass transfer of the corrosion products away from the metal surface, while in the intermediate range, where protective scales might just form, high flow intensity (turbulence) leads to localized corrosion and so called "mesa" attack.

The effective inhibitor concentration (EIC), i.e., the concentration required in the field to reach a low target corrosion rate at which localized attack is minimized, depends on environmental parameters in a complex manner. An attempt is made in Table 2 to summarize these relationships qualitatively.

**Table 2**

| **Effect of** | **Direction of Change** | **Effect on required Inhibitor Concentration** |
|---|---|---|
| **Decreasing pH on** | | |
| Corrosion | ↑ | ↑ |
| Scale Formation | ↓ | ↑ |
| **Increasing Flow on** | | |
| Corrosion | ↑ | ↑ |
| Scale Formation | ↓ | ↑ |
| **Increasing Pressure on** | | |
| Corrosion | ↑ | ↑ ↓ |
| Scale Formation | ↓ | ↑ ↓ |
| **Increasing Water/Oil Ratio on** | | |
| Corrosion | ↑ | ↑ ↓ |
| Scale Formation | ↔ | ↓ |

As indicated earlier, a decreasing pH increases corrosion while preventing the growth of protective scales with the result that higher EIC's are needed for adequate protection. The flow rate (and by implication the flow intensity at flow upsets) similarly results in a requirement for higher EIC. These relationships have been demonstrated quantitatively in previous publications (Ref. 2,3,4).

The pressure effect is peculiar in that there appears to be a maximum in the Corr.rate / pressure curve for different inhibitor concentrations. This was first demonstrated in studies related to another $CO_2$ sandstone flood (5). Recently similar studies were performed with Inhibitor C in use at the Postle field. Figure 1 indicates by means of iso-corrosion lines presented as contours in the $P_{CO2}$ vs. rpm (velocity) grid, that at certain velocities, and for certain metals[2)] the pressure effect might have a maximum at certain inhibitor concentrations. These data also indicate that the usage rate of 20 ppm inhibitor in the field very likely was not enough and that under certain high velocity conditions even 100 ppm would not be sufficient.

It was against this background that an attempt was made to establish a model for the effective inhibitor concentration as a function of $CO_2$ partial pressure, rpm (flow rate), and the water/oil ratio (Ref. 4). The data had indicated that under the most corrosive conditions in the laboratory high concentrations of inhibitor were needed, again depending on the metallurgy. The opportunity then existed to verify the laboratory data in the field by direct real time downhole corrosion measurements.

## DESIGN OF FIELD TEST

### 1. Objectives

The objectives of the field test were formulated as follows:

- Determine the effectiveness of the corrosion inhibitor in terms of degree of protection and EIC.
- Confirm the corrosion inhibition model in a limited number of field tests under the most severe corrosion conditions possible.
- Focus on inhibition of tubing corrosion
- Determine the effectiveness of the inhibitor treatment for different continuous injection modes (various lengths of capillary)

The focus was on tubing corrosion initially because the tubing intervals were where the lowest corrosion inhibitor concentrations were anticipated. Since the corrosion inhibitor dosage was determined on the basis of the total volume of produced fluids, the inhibitor concentration in the annular space was expected to be many times higher in proportion to the overflush relative to the total volume produced. If only 5 percent of the total fluids were circulated, the concentration in the annulus would be 20 times higher than anticipated in the tubing. It could, therefore, be assumed that if the tubing id was inhibited, the casing space would be inhibited as well, even if due to high gas production rate the flow intensity in the annulus was even higher, provided the inhibitor – overflush mixture was not blown out of the casing space because the critical gas velocity had been exceeded[3)].

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[2)] This maximum appeared to be present at about 425 psi and 1000 rpm only for J-55 metal. For N-80 and L-80 the maximum might have been shifted to higher $CO_2$ pressures while the corrosion rates at 100 ppm inhibitor concentration were considerably higher as well.

[3)] The critical gas velocity is the velocity at which liquid is gas lifted out of the casing space.

## 2. The Tool

A new tool, the downhole corrosion monitoring system had recently become available from NOVA Corporation[4)]. The system had been extensively field tested by ARCO Alaska in 1997 (Ref. 6). The corrosion measuring device consists of a standard, cylindrical, electrical resistance probe attached to a power supply, and the electronic measuring and data storage circuitry. The assembly is packaged into a 1.25 inch x 54 inch stainless steel tube which can be placed by special wireline tools at any depth in the production tubing (Figure 2). Because the flow channel was reduced due to the placement of the tool, the first joint above the pump was replaced with a 13% Cr steel joint. This prevented corrosion damage which might otherwise occur to carbon steel in the unusually aggressive conditions found in Postle wells.

## 3. The Test Wells

A typical completion scheme of Postle wells is shown in Figure 3. Only few wells were equipped with full length inhibitor injection capillaries. Most wells only had a 40 ft stinger capillary to assure that, for continuous inhibitor injection with overflush, the turbulent zone in the annulus near the well head was bypassed, thereby preventing fluids injected into the annulus from being entrained in the gas. A special feature of the downhole completion is the gas separator, placed between the pump intake and the pump itself. It is estimated that the free gas entering the pump intake was separated from the liquids with about 80% efficiency. Measurements actually indicated that almost all free gas was produced out the annulus, while only dissolved gas in equilibrium with the downhole pressure (at the pump intake) was carried with the liquid. The pump intake pressure was controlled by the fluid level above the pump and the flowline pressure on the surface. In those cases where the wells were equipped with only a 40 ft capillary, the fluids below the pump intake could not be inhibited. Carbon steel equipment below that point was therefore subject to corrosion.

## 4. Selection of the Test Wells

The cost of the test, consisting of the rental of the equipment and three wireline jobs (see below), precluded a broad based test matrix. Therefore, the verification of the inhibitor model was to occur only under the most severe conditions. The criteria for the selection of the test wells were as follows:

- Low level of bicarbonate in the produced water (< 200 ppm)
- High gas rate (>500 MSCFD)
- High liquid flow rates (> 1000 bbl/d)
- Low and high water/oil ratio
- Versatility for inhibitor injection mode

The last criterion was intended for verification of models which helped assessing the critical gas velocity above which liquids are gas lifted out of the casing space. Because of workovers, temporary shut-ins and miscellaneous failures the selection was restricted to a small number of wells and kept changing.

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[4)] NOVA Technology Corporation, 3501 Highway 90 East, Broussard, LA, 70518, formerly a Division of Rohrbach Cosasco Systems, Inc.

## 5. The Structure of the Downhole Tests

The corrosion monitoring tool was located in the 13% Cr-steel joint immediately above the pump to capture the effects of the high turbulence of the fluids exiting the pump and the maximum downhole temperature expected to be around 150 to 160 $^{O}$F. Since a decision had been made to determine the effectiveness of the inhibitor it was necessary to establish the uninhibited corrosion rate prior to inhibitor injection. Therefore an elaborate procedure was worked out to assure removal of all residual inhibitor from the wellbore prior to running the tool into the well. The uninhibited corrosion was monitored for 5 days under normal production conditions in order to establish the steady state uninhibited corrosion rate. Subsequently, inhibitor injection was initiated at the highest rate for about 1 day. The probe was then pulled and replaced with a fresh one. Subsequently it was intended to change the inhibitor injection rate from 300 ppm in 4 steps down to 50 ppm running each concentration for 5 to 7 days.

The liquid flow line of the test well was equipped with a PAIR™ (LPR) meter, an electrical resistance probe, and, where possible, a corrosion coupon. Both meters were continuously reading instruments with data storage capabilities.

The production rates, producing conditions (fluid level, tubing and casing FWHP and FWHT), inhibitor injection rates water analyses and iron counts were recorded as frequently as practical.

The downhole ER-probes were weighed and calipered before and after the test to compare the instrumental read-out with the average weight loss corrosion rate and the appropriate dimensional changes.

Two options existed for the choice of the ER-probes, 10 mil and 20 mil wall thickness with a useful life of 5 and 10 mils respectively. Based on sensitivity considerations it was desirable to use the thin-walled probes for the inhibited test periods. The thick-walled probe, however, had to be used for the uninhibited period because potential corrosion rates of the order of 500 mpy were anticipated, in which case the useful life of the thin probe would have been exceeded in 5 days. These requirements necessitated replacement of the thick-walled probe after the blank test period in order to avoid going into the inhibited test periods with a partially, or fully, used up probe. As it turned out, this precaution was not necessary, because the observed corrosion rates were lower than anticipated.

# RESULTS AND DISCUSSION

## 1. PUMU 9-6

1.<u>The Field Test</u>

The first test well was PUMU-9-6. The production was about 200 bbl/d oil, 250 bbl/d brine and 182 Mscfd gas. In this respect, the well did not correspond to the selection criteria, but it did have both a full length and a 40 ft capillary and water analyses prior to the test showed low bicarbonate content. Figure 4 shows the test sequence in the form of a timeline. Prior to the installation of the downhole probe the procedure of removing all inhibitor from the well was executed. The uninhibited test period lasted 3 days. The thick walled downhole probe used in the blank run was then replaced with a thin walled one, and the inhibitor injection rate was reduced from 300 ppm to 200 ppm because neither the surface nor the downhole ER probes had shown any corrosion toward the end of the blank test period. When it appeared that still no corrosion was observed during the next few days, the inhibitor concentration was reduced to 20 to 25 ppm and left there for the next 25 days. At this point the test was terminated.

Figure 5 shows the response of the downhole ER probe along with the temperature record. The temperature of the fluids immediately at the exit from the pump was about 176 $^{O}$F (80 $^{O}$C) and increased gradually toward 180 $^{O}$F during the 4 day run. This was considerably higher than what had been expected (140 to 150 $^{O}$F for the formation temperature) and included the heat generated by the downhole pump motor and the pump itself (friction). The ER trace goes through an initial minimum which has never been fully explained. Presumably both the battery and the electronic circuitry go through a period of adjustment to the higher downhole temperature, during which time the battery voltage increases and the circuits reach a steady state. After this initial minimum, a period of high corrosion (117 mpy) is followed by rapid passivation (presumably scale formation and/or natural inhibition).

Figure 6 shows a complete evaluation of the ER probe response for the first test period. An initial corrosion rate of 117 mpy is observed for about a day. Afterwards, a full day prior to the injection of the inhibitor, passivation occurs and the corrosion rate decreases to about 1.5 mpy. Figure 7 shows the surface ER probe trace during the same period. Unfortunately some data for this period were lost. Nevertheless, there is a good indication that the downhole passivation process is mirrored in the surface probe.

The main result from this period is that for some time the downhole corrosion was 117 mpy. (This compares favorably with subsequent data – see below). The corrosion rate on the surface for this short period was only 34 mpy. Passivation occurred in both instances.

After the new thin walled ER probe had been run into the well the inhibitor concentration was reduced to 200 ppm for a few days, and when it became obvious from the surface probes that corrosion was not increasing, the concentration was further reduced to 20 to 25 ppm. There was never any indication that the corrosion rate, downhole or on the surface was any larger than the detection limits of the instruments (0.1 mpy) for the period of observation.

2. Discussion

This test showed that carbon steel corrosion was inhibited naturally by the produced fluids. The weight loss corrosion rate obtained from the downhole ER probe matched the integral of the electronic readout. Extensive calipering showed no measurable loss in the diameter. The downhole ER probe was judged very reliable. Table 3 indicates that the production rates held steady over the entire test period. The answer for the absence of corrosion in this well under the prevailing conditions, therefore, must be found in the chemistry of the produced fluids.

Table 4 lists water analyses from shortly before, during and after the test. It appears that there has been a shift of the bicarbonate concentration causing a shift in pH from 4.3 to 4.9, i.e. from a non-scaling ($FeCO_3$) to a scaling condition. The iron carbonate saturation pH is estimated at about pH 4.4 to 4.5 at 180 $^{O}$F (Ref. 1). Additionally, the produced oil proved to be paraffinic in nature (as judged from paraffin deposits on the surface probes). It is, therefore, concluded that the combination of relatively low production rates, higher than expected downhole temperature, an unexpected shift in pH favoring iron carbonate film formation, the low water/oil ratio, and the paraffinic nature of the oil all worked together to generate a non corrosive condition.

## 2. HMAU 54

1. The Field Test

The second test well was HMAU-54 with an average production of 2500 to 2800 bbl/D brine, 140 to 150 bbl/d oil and 230 to 250 Mscfd gas. The $CO_2$ content in the gas was of the order of 80% and the fluid level was consistently high between 1500 and 2000 ft above the pump. This well was also equipped with a full length capillary (see Fig. 3) and a 13% Cr-steel joint had just been installed immediately above the pump where the tool was to be placed. Prior to running the probe into the well, all remaining inhibitor from the previous treatment was flushed out of the casing and tubing. Table 5 shows water analyses from before and during test. The bicarbonate levels appeared to be quite low. The test sequence and timeline is shown in Figure 8.

Figure 9 shows the downhole ER probe response during the uninhibited (blank) period. The corrosion rate starts out at 120 mpy (vs. 117 mpy on the PUMU 9-6 for the first hour), and reaches a steady state of 82 mpy after 1 day. The inhibitor injection was initiated at 265 ppm after 4.5 days. The delay of the probe response is due exactly to the time it took for the inhibitor to fully displace the xylene in the capillary. The inert solvent had been used to purge all inhibitor from the capillary and was left there during the blank period. As soon as the inhibitor reached the pump intake, the corrosion rate decreased to a very low level of 2.2 mpy. The downhole temperature during the blank run was 154 $^{O}$F and held steady during the entire period. Figure 10 shows the response of the surface ER probe. The initial corrosion rate decreased from 90 mpy to 67 mpy during the first 5 days. After the inhibitor reached the surface a corrosion rate of 4.7 established. The blank test was terminated before steady states had been established, either downhole nor on the surface. The surface probe mirrored the downhole trends, albeit at a somewhat lower level. Prior to starting the inhibited period of this test, new probes were installed in both locations.

Figure 11 shows the record of the downhole ER probe during the inhibited period. It took a few hours for the inhibited corrosion rate to establish itself on the new probe. The steady state leveled out at 1.3 mpy. During the transient a corrosion rate of 17 mpy was extrapolated from the data. (Not enough points could be recorded to extrapolate a good number from the somewhat noisy data). After the injection rate was changed from the 265 ppm to 150 ppm the corrosion rate increased from 1.3 mpy to 4.1 mpy over a very short period of time. (The "film" life was only 3 to 5 hours at best). The same behavior is seen on the new ER probe on the surface as shown in Figure 12. It took a few hours for the corrosion probe to become fully inhibited. At 265 ppm the corrosion rate is practically zero, or so low (>1 mpy) that no meaningful value could be extracted from the 48 hour record (the statistical trend of the data is negative). At 150 ppm a corrosion rate of 1.2 mpy could be determined from the 7 day record.

After the inhibited period had been running for about 10.5 days an upset occurred. The surface flowline was accidentally shut in such that the pump deadheaded for a period of time. During this period and before the pump shut down, the fluid temperature reached 350 $^{O}$F (see Fig. 11). The corrosion rate increased to about 15 mpy, but when the temperature had receded to 149 $^{O}$F, the corrosion rate stabilized at a level of about 0.5 mpy under stagnant conditions. Whether the low corrosion rate is due to passivation or inhibition is impossible to determine. However, the temperature excursion did not cause any damage, which was confirmed by subsequent workover.

The behavior of the LPR probe is shown in Figure 13. During the uninhibited period a corrosion rate of 2.5 mpy can be averaged out from the extremely noisy data with some confidence. However, during the inhibited period, the measurements were practically zero. All fluctuations are due to the electronic bit-noise off zero.

2. Discussion

Table 6 summarizes the results from the second test. The downhole corrosion protection at 265 ppm was 98.4 % and 95 % at 150 ppm inhibitor concentration. This is probably for the first time that such high degrees of protection have been shown in the field under downhole conditons for any corrosion inhibitor. The degrees of protection derived from the surface data are even better, 99.4 % and 98.2% for 265 and 150 ppm, respectively. This points to the important fact, long suspected but never quantitatively demonstrated, that surface corrosion rate measurements do not reflect the real downhole situation. Qualifying comments need, however, be made. While inhibition may have been favored by the lower temperature on the surface, suspected turbulent conditions may have tempered this effect. It has been calculated that gas break-out from the liquid in the tubing occurred at about 2000 ft from the surface. The mixture velocity was thereby accelerated from 9 to 16.7 ft/sec. The surface probe was therefore exposed to a much higher flow rate and much greater turbulence than the downhole probe. In the absence of such gas break-out, inhibition on the surface might have been even better. The LPR probe response was many times lower than the ER responses even though the water/oil ratio was from 12 to 14, a water cut usually thought to be very favorable to LPR measurements. Two effects may have been responsible for this. It had already been observed in extensive autoclave corrosion measurements (Ref. 4) that with Inhibitor C the weight loss/LPR ratios were quite high. They generally increased with inhibitor concentration and could be as high as 20 with an average around 5 to 10. This phenomenon depends on the nature of the inhibitor and of course the water cut. On the other hand, the high gas volume commingled with the fluids on the surface (about 45 vol% gas and 55 vol% liquids) no doubt was also responsible for the low LPR readings as well as the extreme noise observed in the data. All this points to the need for caution in interpreting surface corrosion measurements. The difference between an instrumental reading of 4 mpy (general corrosion rate) and 1 mpy is not trivial in view of possible localized corrosion (pitting factor). It had been shown in the previous paper, by means of autoclave testing and extensive pit measurements, that localized attack occurs under partially inhibited conditions when corrosion rates exceed 1 mpy. A surface corrosion rate reading of 1 mpy ( with concomitant downhole corrosion of 4 mpy) is no assurance that pitting or localized attack (FILC) has been inhibited downhole. The customary pitting factor of 20 often accepted in the oil field as relating general corrosion to localized corrosion seems to confirm these conclusions.

Iron counts had been measured occasionally during these tests. The average tubing corrosion rates derived therefrom for bare tubing are independent of the presence of inhibitor or its concentration. The tubing furthermore had been internally plastic coated. All this confirms that soluble iron was produced with the brine from the formation and that iron count measurements therefore would be useless for the purpose of monitoring inhibitor effectiveness.

In summary it can be concluded that this new corrosion monitoring system is an excellent tool with which one can begin to resolve a number of open questions related to monitoring of corrosion and corrosion inhibition. Differences between downhole and surface corrosion rates must be interpreted carefully and some commonly used tools for measuring corrosion rates at surface may not be entirely reliable. At the least it has been possible to put in perspective the reliability of some of the more common oil field practices. More importantly, it has been shown that the degree of inhibition in the field under realistic conditions is much higher than commonly believed. The factors which control the degree of inhibition will be discussed below.

## INHIBITION MODEL

The objective of modeling corrosion inhibition is to extract from the accumulated laboratory (Ref. 4) and the newly acquired field data a means to predict the effective corrosion inhibitor concentration (EIC) which would result in a predetermined (target) corrosion rate under field conditions. Since almost every producing well in a $CO_2$ flood exhibits different producing conditions the EIC for each well is different. A corrosion inhibition model is, therefore a prerequisite for optimizing the inhibitor program cost field wide and by implication minimizing the maintenance expenditures.

The modeling process begins by setting a target corrosion rate, determined by the life expectancy of the field, the anticipated pitting factor, the acceptable treatment cost, or any other operational parameter which might be considered a priority. The target corrosion rate is, therefore, subject to a decision by the operator of the field. Once the target corrosion rate has been established, the inhibitor performance curves are used to define the EIC's for different pressure and velocity conditions. The methodology has been described in detail in the previous publication (Ref. 4). From an array of EIC's defined for different $CO_2$ partial pressures and different flow conditions, contour plots are generated for constant inhibitor concentration. These curves are generated from laboratory data obtained by means of the high speed autoclave test. The velocity vector is therefore expressed in rpm of the rotating cage. In order to verify this laboratory developed model and give it practical utility, one needs to translate the flow intensity of laboratory conditions to those prevailing in the field. To achieve this task explicitly is a real challenge since the rotating cage used to generate the laboratory data is not really a rotating cylinder, and the downhole ER-probe used to generate the field data is not necessarily exposed to the same flow intensity as the tubing walls in which it resides during the test. In the face of these difficulties, and the absence of an abundance of data, only a qualitative attempt can be made at the comparison of the two data sets. The approach, as intuitive as it might be, may stimulate further efforts in this direction, and perhaps begin to put in perspective the many misleading and erroneous claims being made about the art of chemical corrosion inhibition.

In analogy to Efird's work (Ref. 7) the wall (or surface) shear stress was used to link the laboratory results with the field data. The overall methodology was as follows:

- Determine the shear stress of the rotating cage ($\tau_{rc}$) as function of rotating speed of the cage ($rpm_{RC}$).
- Determine the shear stress at the downhole tool in terms of the tubing shear stress ($\tau_{tbg}$)
- From the correlation of ($rpm_{RC}$) = f($\tau_{rc}$) determine the "apparent equivalent" ($rpm_{tbg}$) using ($\tau_{tbg}$)
- Enter the apparent equivalent shear stress into the contour plot for the effective inhibitor concentration.
- The difference between the EIC extrapolated for ($rpm_{tbg}$) and the ($rpm_{RC}$) corresponding to the concentration used in the field will yield an empirical factor by means of which ($rpm_{tbg}$) is to be adjusted in order to make the contour plot (laboratory data) predictive in terms of the

concentration which needs to be used in the field in order to achieve the target corrosion rate for which the contour plot has been defined.

The contour plot is used to facilitate the understanding of the methodology. The same procedure can be formulated analytically as will be shown later. The shear stress calculations for the rotating cage were based on a discussion by Silvermann (Ref. 8, 9). The results are shown in Figure 14 along with an empirical correlation equation which was extracted solely for ease of future calculations. The tubing shear stress was calculated on the basis of Efirds discussion (7). For the conditions found in HMAU 54 (tubing diameter 2 3/8 inch, brine production 2800 bbl/d, oil production 150 bbl/d, temperature 150 $^{0}$F) the tubing shear stress ($\tau_{tbg}$) was found to be 13 N/m$^2$. This results in an apparent equivalent tubing rpm ($rpm_{tbg}$) as extrapolated from Fig. 14 of 706.
The $CO_2$ partial pressure in the fluids above the pump was estimated at 550 psi. Referring to Figure 15, the contour plot for 1 mpy, one can see that the apparent equivalent tubing rpm would, at 550 psi $CO_2$, predict an EIC of about 90 ppm. From the field data one knows however, that the target corrosion rate of (about) 1 mpy was attained with 265 ppm which corresponds to 1411 rpm. The relationship between ($rpm_{tbg}$) and ($rpm_{RC}$) therefore is almost exactly a factor of 2. From a practical point of view this means that if the apparent equivalent tubing rpm is determined from the actual tubing shear stress and multiplied by a factor of two, one can determine the effective inhibitor concentration from the contour plot for any pair of production rate and $CO_2$ partial pressure. The procedure is confirmed by the second field data point from HMAU 54. Figure 16 shows the contour plot for 4 mpy. The production conditions are the same as above. Extrapolation of the EIS for the apparent equivalent rpm of 706 results in an apparent EIC of 60 ppm. However, 4 mpy was obtained in the field with 150 ppm corresponding to a cage rpm of 1420. The factor of two is thereby confirmed.

Efird (7) has shown that at equal shear stress the corrosion rate obtained on a rotating cylinder is about two to three times less than that observed in tubular flow. Equal corrosion rate would therefore require a higher shear stress (higher rpm) on the rotating cylinder by about the same factor as observed above. Since a higher corrosivity requires more inhibitor to achieve the same target corrosion rate [5], and since a lower tubular shear stress represents a higher corrosivity than equal rotating cylinder shear stress, it is clear that both the inhibitor concentration as well as the cylinder rpm would have to be increased to match the field conditions. It appears, therefore, that the data presented here and their interpretaion, albeit dealing with corrosion inhibition rather than corrosion itself, find confirmation in the work presented by Efird.

In order to develop the model quantitatively the data for the EIC's as a function of rpm and $CO_2$ partial pressure were expressed in diagnostic equations rather than contour plots. The equations were obtained by means of a multiple linear regression using JMP™ software[6]. The equations for 1 mpy and 4 mpy are:

$$EIC_{1mpy,J-55} = -117.1 + 0.105 \bullet P_{CO_2} + 0.2285 \bullet rpm$$

and

$$EIC_{4mpy,J-55} = -62.4 + 0.0692 \bullet P_{CO_2} + 0.121 \bullet rpm$$

[5] It has been shown time and again that the more corrosive a system the more inhibitor is needed for equal protection in terms of the target corrosion rate (see also for example Ref. 10).
[6] JMP™ is statistical software from SAS Institute Inc., Cary, NC.

respectively. In analogy to the above methodology one first determines the actual tubing shear stress which is then converted to the apparent equivalent tubing rpm. This latter number is then multiplied by two and inserted in the above equations in order to arrive at the EIC associated with the particular production conditions.

This model for corrosion inhibition clearly has limited applicability. While the contour plots do account for the non-linearity observed in the pressure effect, the correlation equations do not. The effect of this on the predicted EIC is small, but must be kept in mind. The correlation equations as well as the contour plots strictly have validity only within the experimental parameter range. More important, however, is the fact that the results presented here are both field- and inhibitor specific. The same inhibitor in high bicarbonate brine would result in lower EIC values, while different inhibitors in the same field can vary dramatically in their respective EIC requirements. Superimposed on this are the different responses obtained from different metals. It has been pointed out that L-80 under high flow intensity requires much higher EIC's. This highlights the notion, often glossed over in practice, that for optimum inhibitor applications field specific evaluation under realistic conditions is unavoidable. On the other hand, the model does show a way to define the EIC specifically for each well in a field and thereby opens a way toward economic optimization of inhibitor treatments, and selection of corrosion mitigation scheme on more meaningful cost data.

## SUMMARY

Downhole corrosion rate measurements were made with a new tool by NOVA Technology Corporation which is based on electrical resistance technology. The tool was used in two wells to verify the effectiveness of the corrosion inhibitor used field wide. In the first test well, PUMU 9-6, it was found that the inherent uninhibited corrosion rate might be of the order of 120 mpy. This rate was sustained only for a short period of time before passivation set in. Passivation is due to a combination of factors: mild flow conditions, high temperature, high bicarbonate concentration in the brine, and a low water to oil ratio. The steady state corrosion rate was essentially zero, a fact which was also attributed to the natural corrosion inhibiting properties of the produced oil.

The second test was performed under more severe flow conditions, a very high water cut, and higher $CO_2$ partial pressure. Realistic steady state blank corrosion rates were measured downhole and on the surface. Upon adding inhibitor at 265 and 150 ppm degrees of inhibition of 98.4% and 95%, respectively, downhole, and 99.4 and 98.2 %, respectively, on the surface were achieved. Such high degrees of inhibition were previously thought to be unrealistic under field conditions. It was also observed that surface corrosion measurements consistently reflect lower aggressiveness than prevails downhole and therefore, higher inhibitor effectiveness. The importance of this is seen in the fact that in order to prevent failures by pitting and/or flow induced localized corrosion, the general corrosion has to be inhibited below a certain level. A surface corrosion rate of 1 mpy which may correspond to a downhole rate of 4 mpy is no guarantee that localized downhole corrosion has been inhibited.

An attempt was made to model the field results within the framework of the laboratory data using the wall shear stress to translate the field flow conditions to the laboratory flow conditions generated by rotating cage in the high speed autoclave test. Because the calculated shear stress for the cage is higher than the calculated shear stress for tubing at equal corrosion rates, the tubing shear stress (or in the model the apparent equivalent tubing rpm) need to be adjusted upwards in order to estimate the EIC from laboratory data. The proportionality factor is about two and is confirmed by the work of Efird. The model expresses the general experimental findings that the EIC is a function of partial pressure, flow intensity and to a lesser extent the water to oil ratio. It must be stressed, however, that the model is relative. While qualitatively such relationships have been shown for a large number of inhibitors, they differ quantitatively, and depend not only on the inhibitor, but also on the metal to be inhibited and the environment, notably the pH of the brine. While the industry would like to have one simple correlation applicable to all types of carbon steel, all inhibitors and a wide range of environmental conditions, reality defeats such an approach. The notion that oil wells should be treated with 20 or 30 ppm of inhibitor regardless of the nature of the environment and the producing condition is unrealistic. This notion may have been the result of simplified inexpensive laboratory testing procedures and has by now been thoroughly discredited in many parts of the world. Rather, for aggressive conditions as they are found at Postle corrosion inhibitors must be qualified by field specific evaluation. The model, however, can predict the EIC for individual wells in a field. This has been confirmed by in situ, downhole corrosion rate measurements in real time. The novel downhole corrosion monitor has therefore been a big step forward toward in improving understanding of these problems.

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**Table 3**

**Production Data from PUMU 9-6 During Corrosion Rate Test With Downhole Continuous Corrosion Monitor**

| Date | Oil Bbl/d | Water Bbl/d | Gas MSCFD | $CO_2$ % | Csg Pres. psi | Tbg Pres. psi | Csg Temp F | Tbg Temp F | Fluid Level ft |
|---|---|---|---|---|---|---|---|---|---|
| 9/23/97 | 196 | 244 | 182 | 45 | | | | | |
| 9/24/97 | | | | | 188 | 180 | 98 | 103 | |
| 9/25/97 | 205 | 295 | 158 | | 185 | 170 | 96 | 106 | 1005 |
| 9/27/97 | 216 | 298 | 175 | 60 | | | | | |
| 9/28/97 | | | | | 160 | 260 | | | |
| 9/29/97 | | | | | 170 | 285 | 92 | 102 | |
| 10/2/97 | | | | | 182 | 268 | 93 | 100 | |
| 10/3/97 | 199 | 260 | 137 | | | | | | |
| 10/4/97 | | | | | 165 | 262 | 101 | 105 | |
| 10/5/97 | 188 | 269 | 132 | | | | | | |
| 10/8/97 | | | | | 170 | 280 | 88 | 94 | |
| 10/13/97 | | | | | 172 | 290 | 91 | 98 | |
| 10/16/97 | | | | | 168 | 292 | 93 | 101 | |
| 10/21/97 | | | | | 173 | 310 | 91 | 94 | |
| 11/4/97 | | | | | 170 | 205 | 85 | 94 | |

Table 4

# Postle Field Water Analyses

## Field Unit: PUMU

### Well Number: 9-6

| Analysis Date | Chloride mg/l | Bicarb. mg/l | Calcium mg/l | Magnesium mg/l | Iron mg/L |
|---|---|---|---|---|---|
| 3/15/96 | 30442 | 239 | 3414 | 552 | 3.5 |
| 2/26/97 | 32251 | 302 | 3365 | 620 | 26 |
| 7/8/97 | 34873 | 317 | 3575 | 641 | 19 |
| 10/8/97 | 39475 | 927 | 4378 | 856 | 89 |
| 10/10/97 | 39172 | 968 | 4047 | 664 | 78 |
| 3/26/98 | 41117 | 1552 | 3050 | 693 | 127 |

Table 5

# Postle Field Water Analyses

## Field Unit: HMAU

### Well Number: 54

| Analysis Date | Chloride mg/l | Bicarb. mg/l | Calcium mg/l | Magnesium mg/l | Iron mg/L |
|---|---|---|---|---|---|
| 11/4/96 | 79571 | 171 | 9737 | 1390 | 24 |
| 7/1/97 | 93746 | 42 | 10602 | 1444 | 48 |

**Table 6**

**HMAU 54 Corrosion Test with Downhole Corrosion Monitor**
**Comparison of Different Corrosion Rates**

| Inhibitor Concentration | Downhole | | Surface | | | Corr. Rate from Fe cnt. |
|---|---|---|---|---|---|---|
| | ER- Corr. Rate (mpy) | Percent Protection | ER- Corr. Rate (mpy) | Percent Protection | LPR Corr. Rate (mpy) | |
| Blank (0 ppm Inhibitor) | 82 | *0* | 67 | *0* | 2.5 | 157 |
| 265 ppm CRO-396 | 1.3 | *98.4* | 0.4 | *99.4* | 0 | 174 |
| 150 ppm CRO-396 | 4.1 | *95* | 1.2 | *98.2* | 0 | n.a. |

**Figure 1: Contour Plot of Iso-Corrosion Lines for J-55 at 100 ppm Inhibitor C Evaluated in High Speed Autoclave Test**

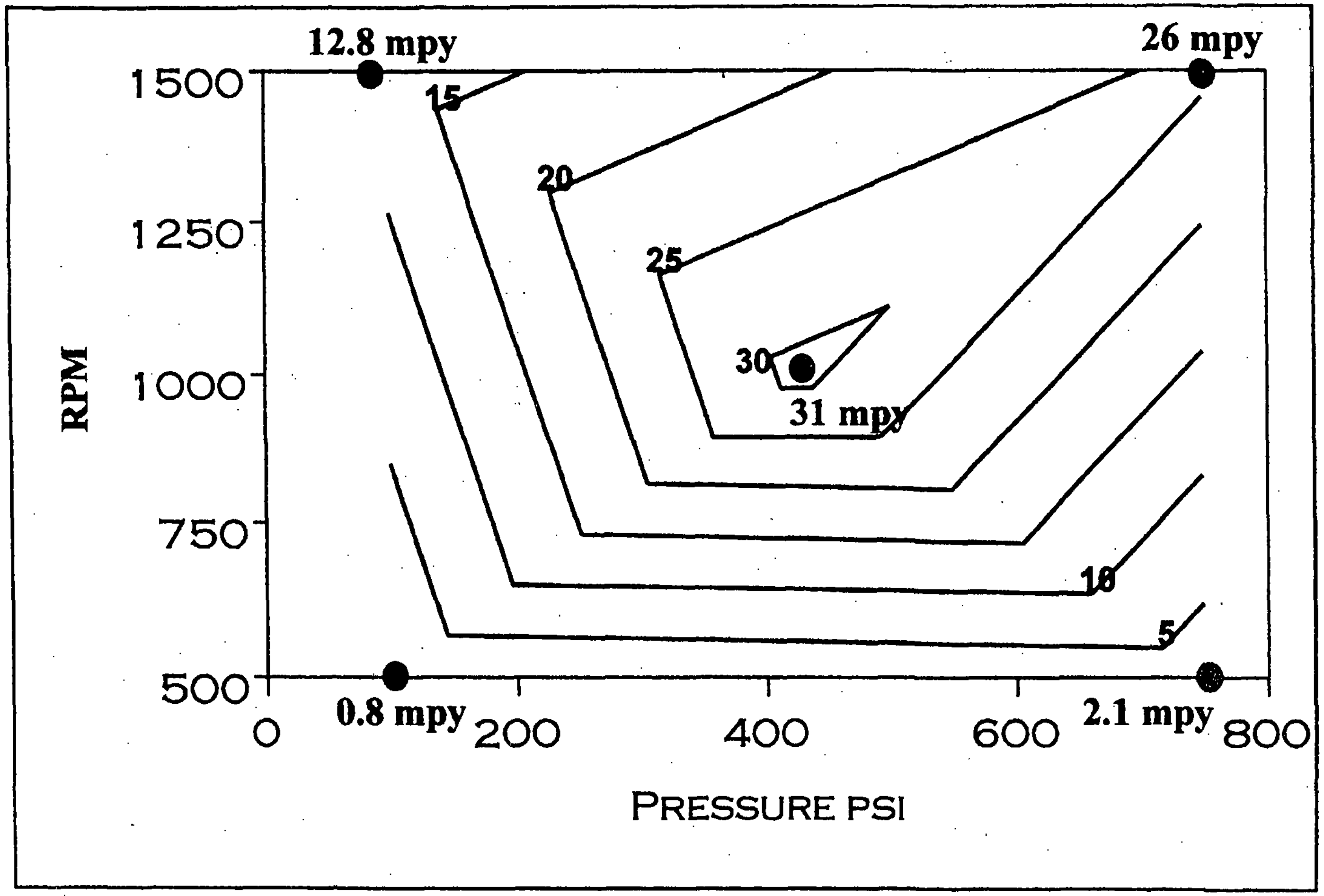
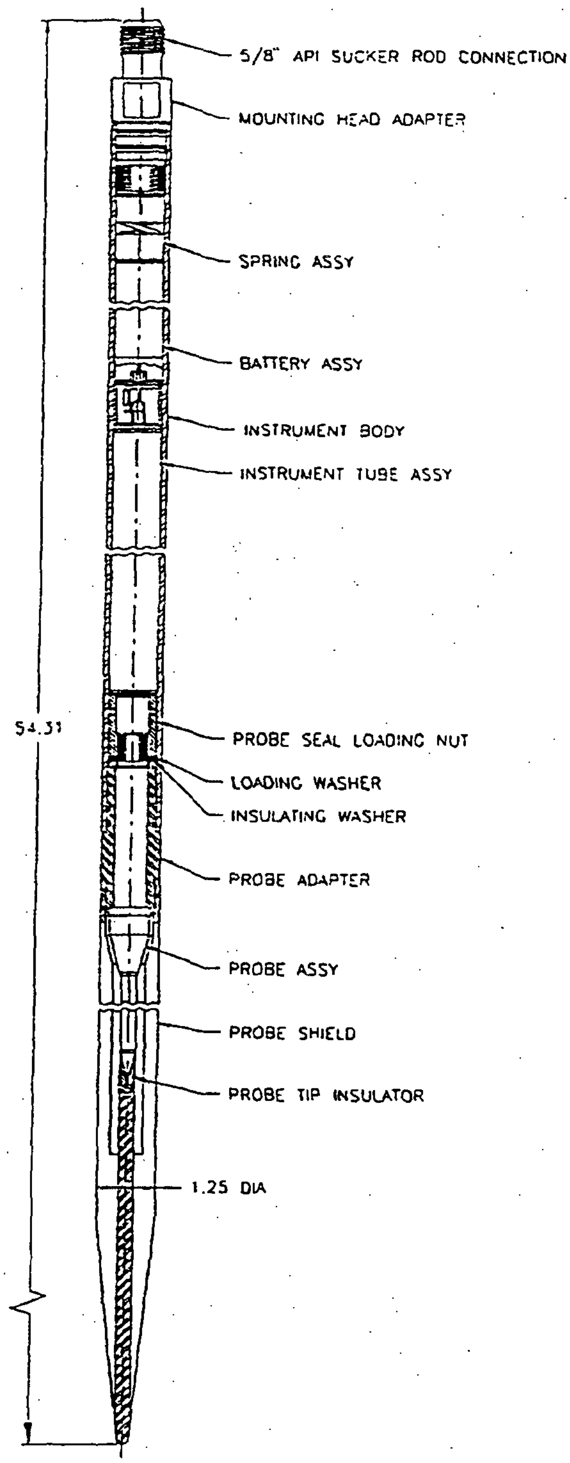


**Figure 2: Cross-Sectional View of Fully Assembled Downhole Corrosion Monitoring System**



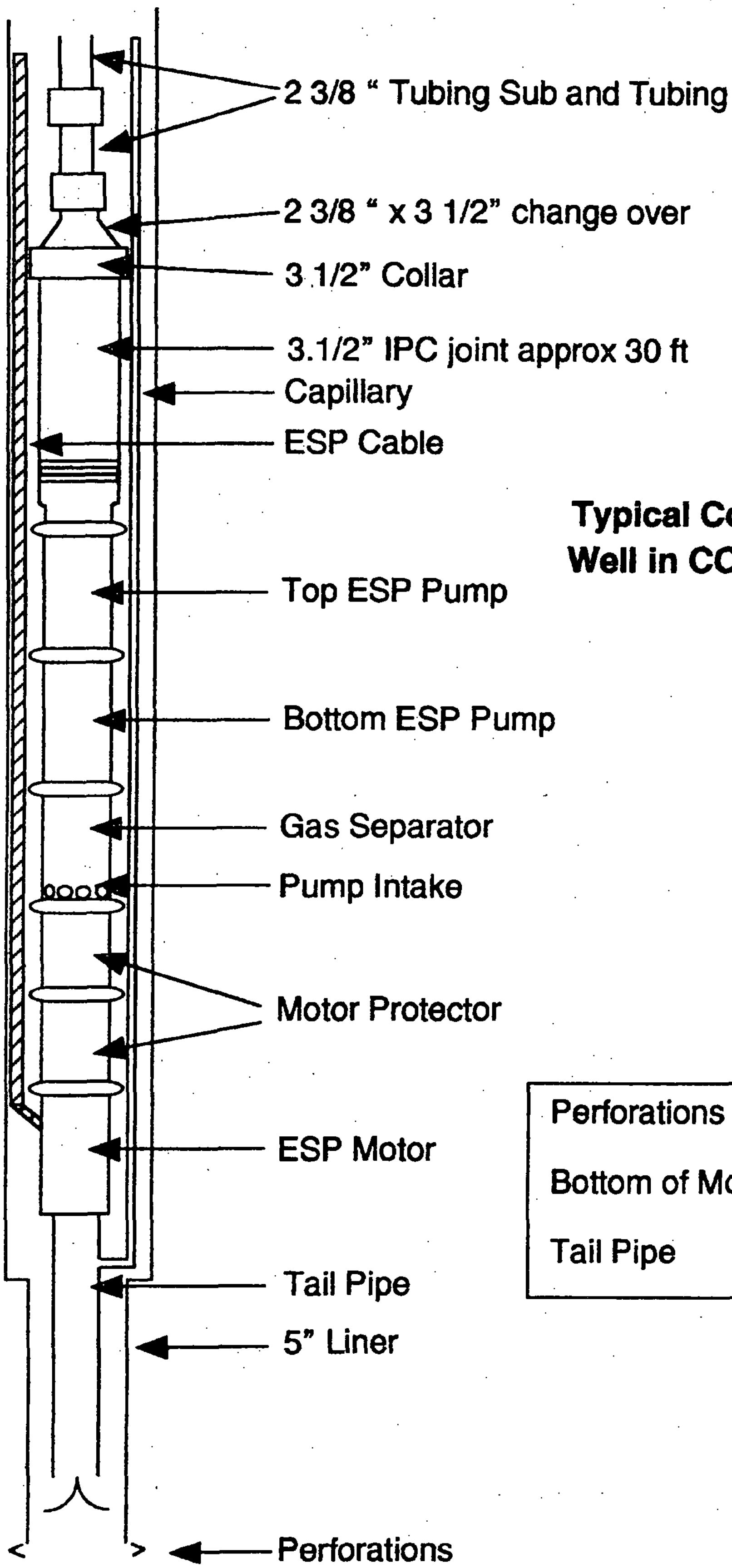



***Figure 3***

**Typical Completion of Producing Well in $CO_2$ Flood with full length Capillary**

| | |
|---|---|
| Perforations | approx 6150 ft |
| Bottom of Motor | approx. 6000 ft |
| Tail Pipe | approx. 100 ft |

**Figure 4: Time Line for PUMU 9-6 Downhole Corrosion Monitoring Test**

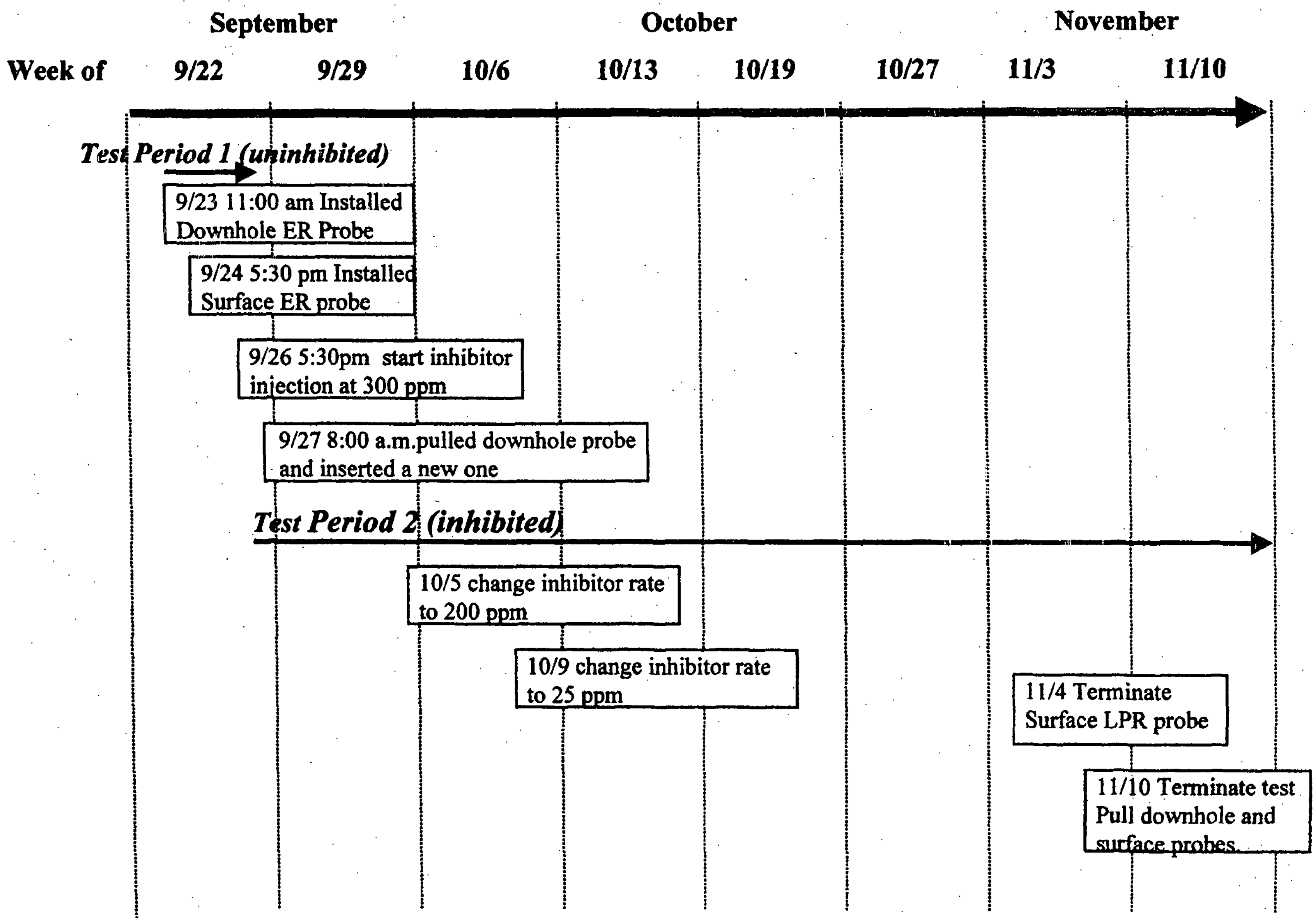


**Figure 5: Pumu 9-6 Downhole Temperature and Corrosion Rate Measurements; Uninhibited Period**

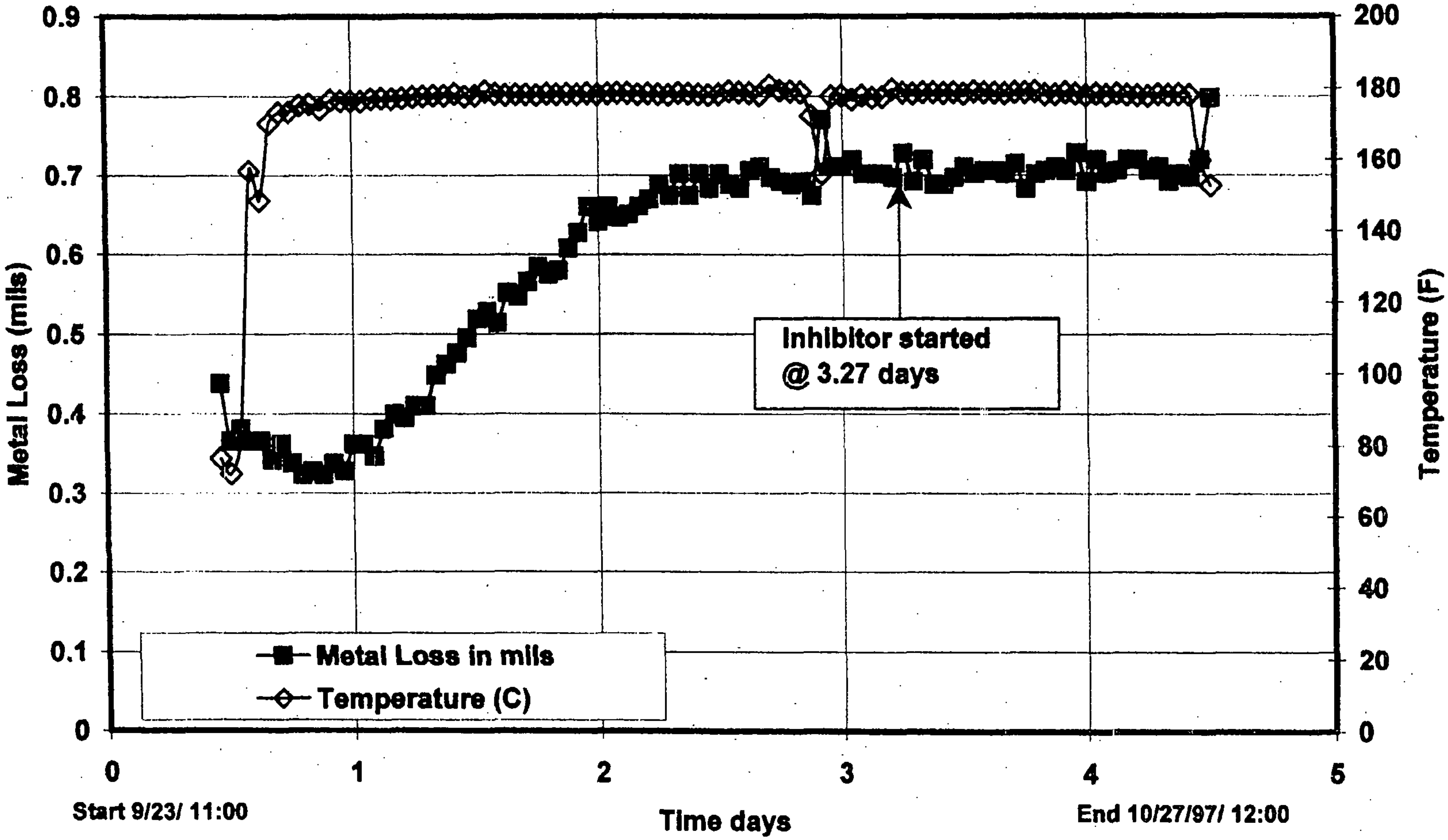


**Figure 6: PUMU 9-6 Downhole Corrosion Rates; Uninhibited Period**

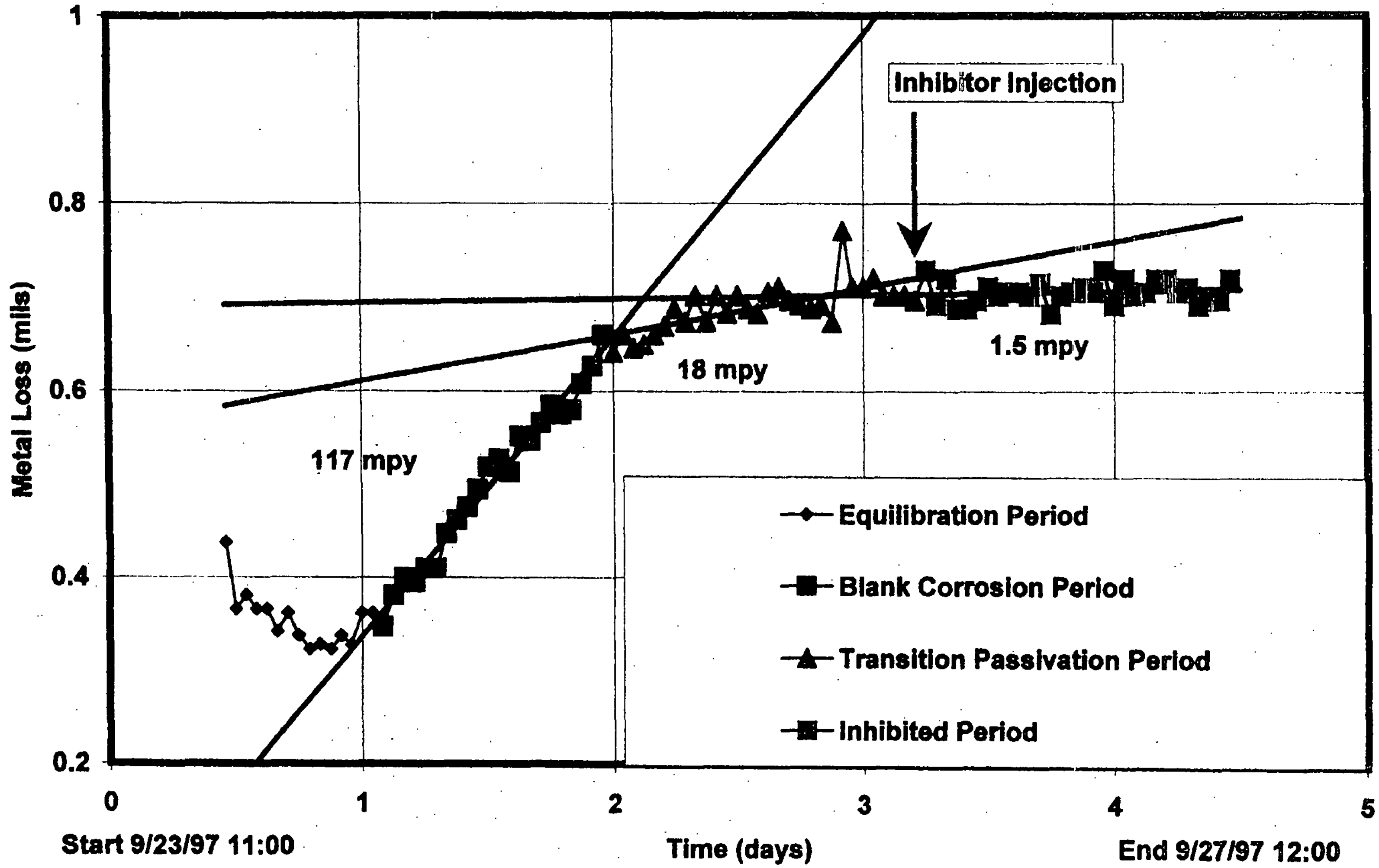


**Figure 7: PUMU 9-6 Surface Corrosion Rate**

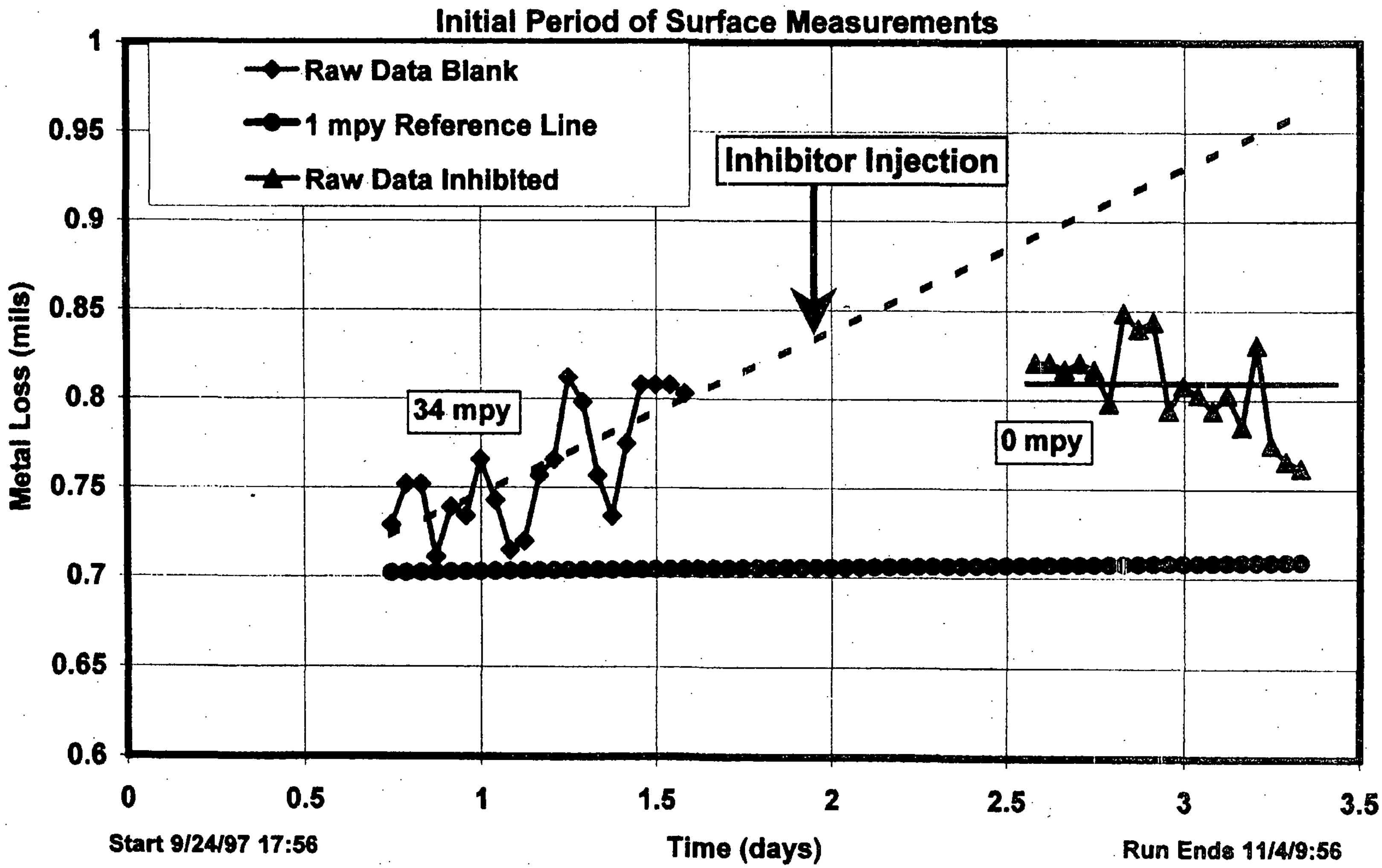
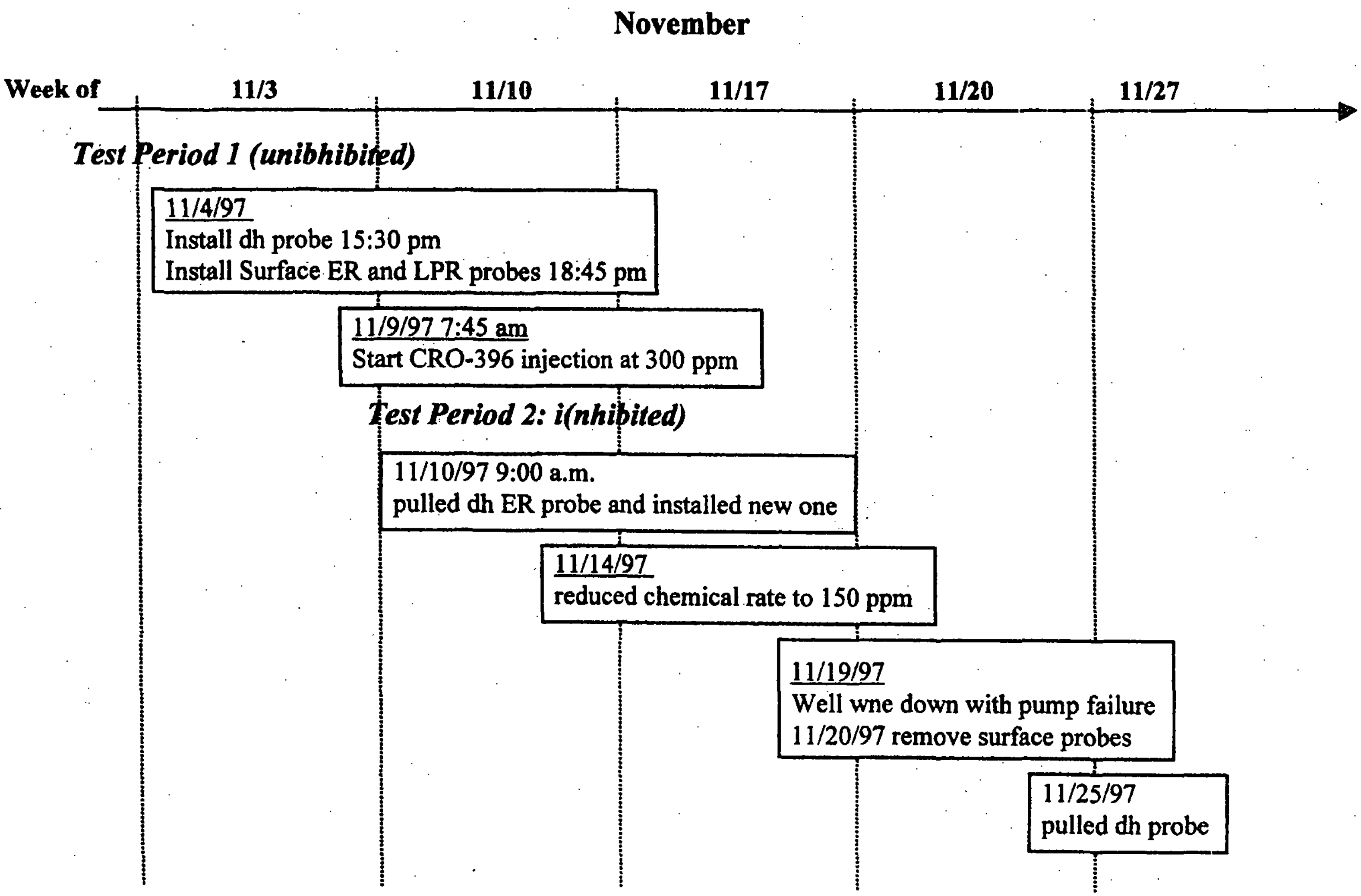


**Figure 8: Timeline for HMAU 54 Downhole Corrosion Monitoring Test**



## Figure 9: HMAU 54 Downhole Corrosion Tool

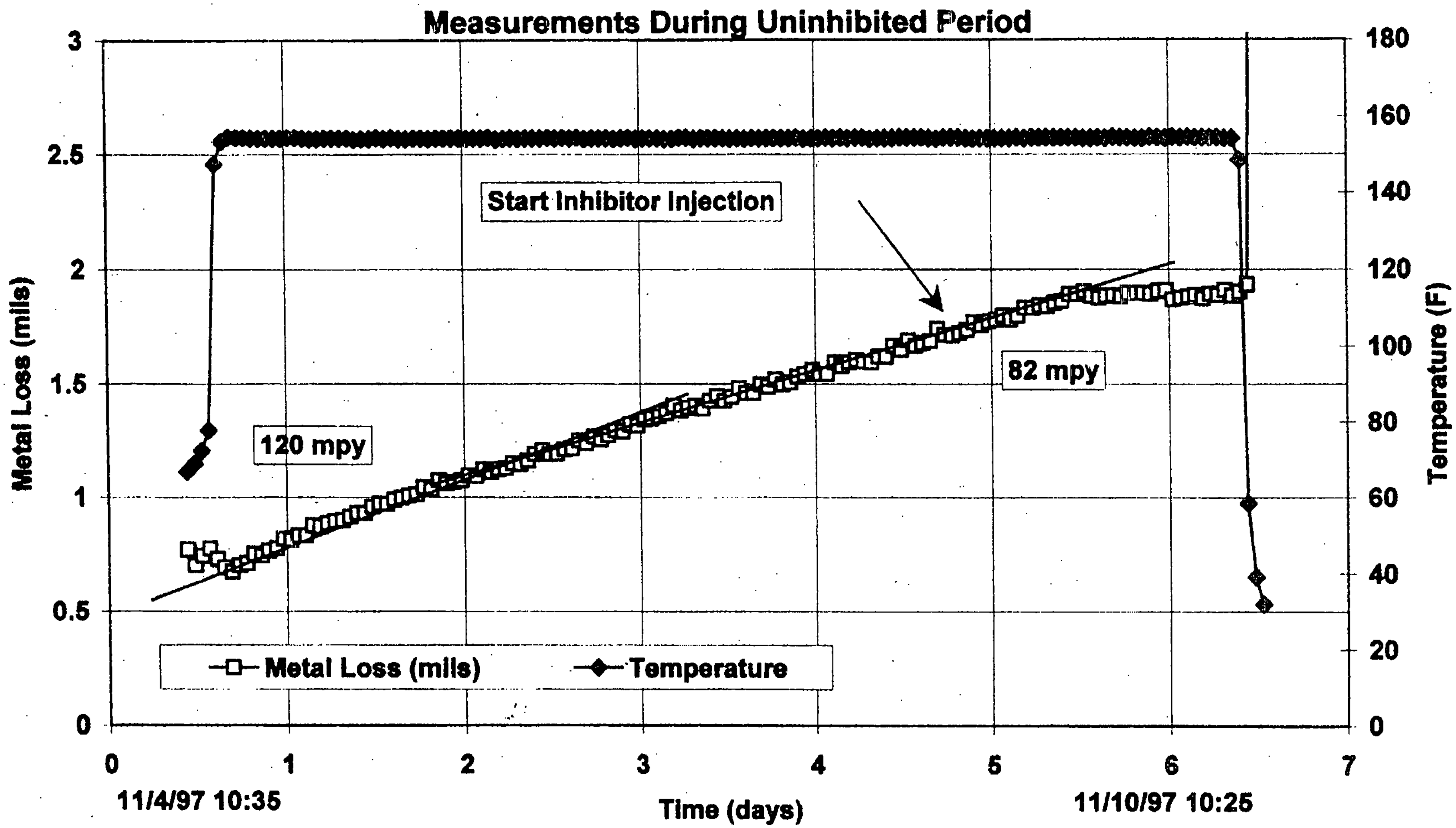


**Figure 10**: HMAU 54 Surface ER Probe
Uninhibited Period

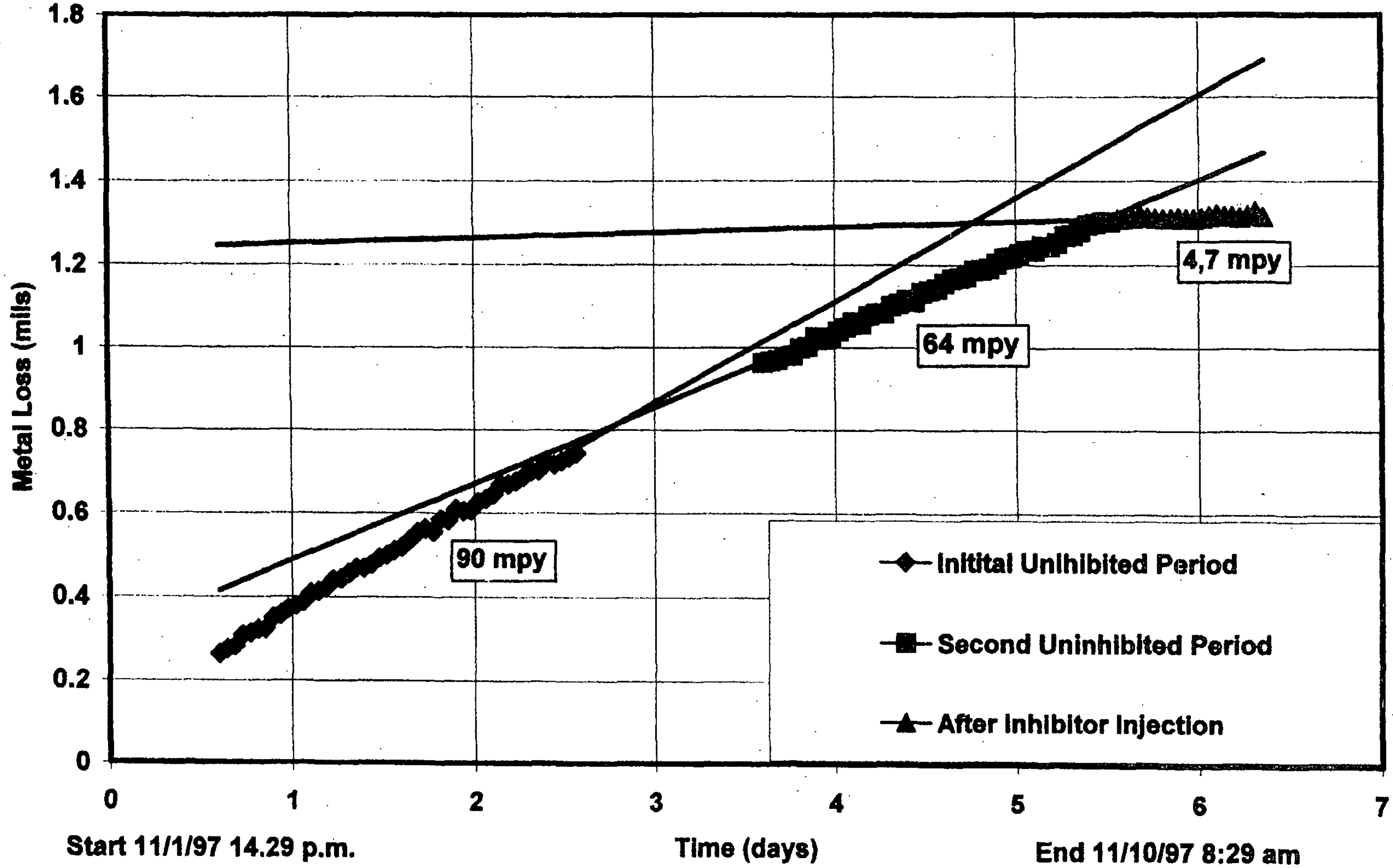
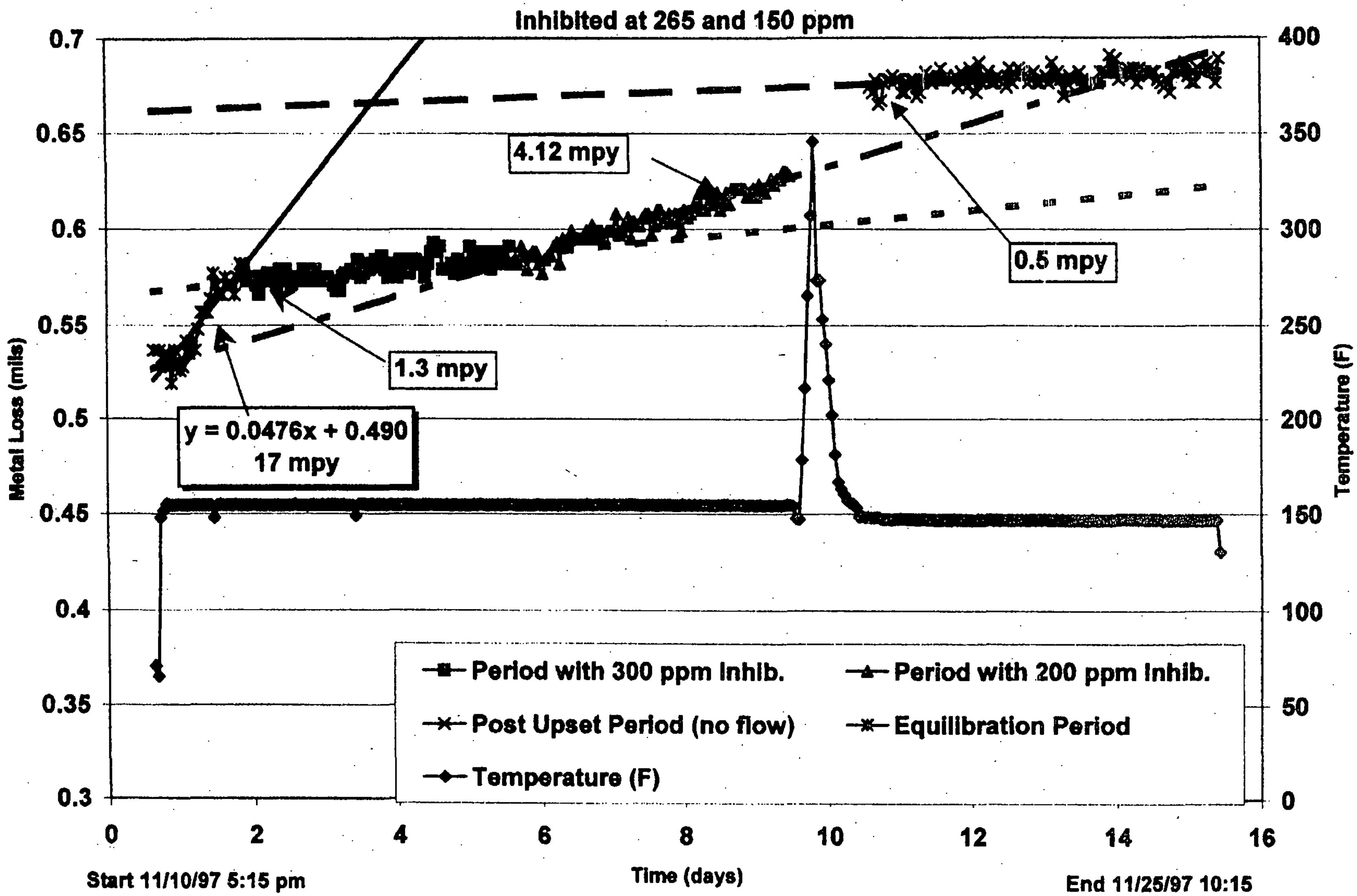


**Figure 11: HMAU 54 Downhole Corrosion Monitor: Inhibited Periods**



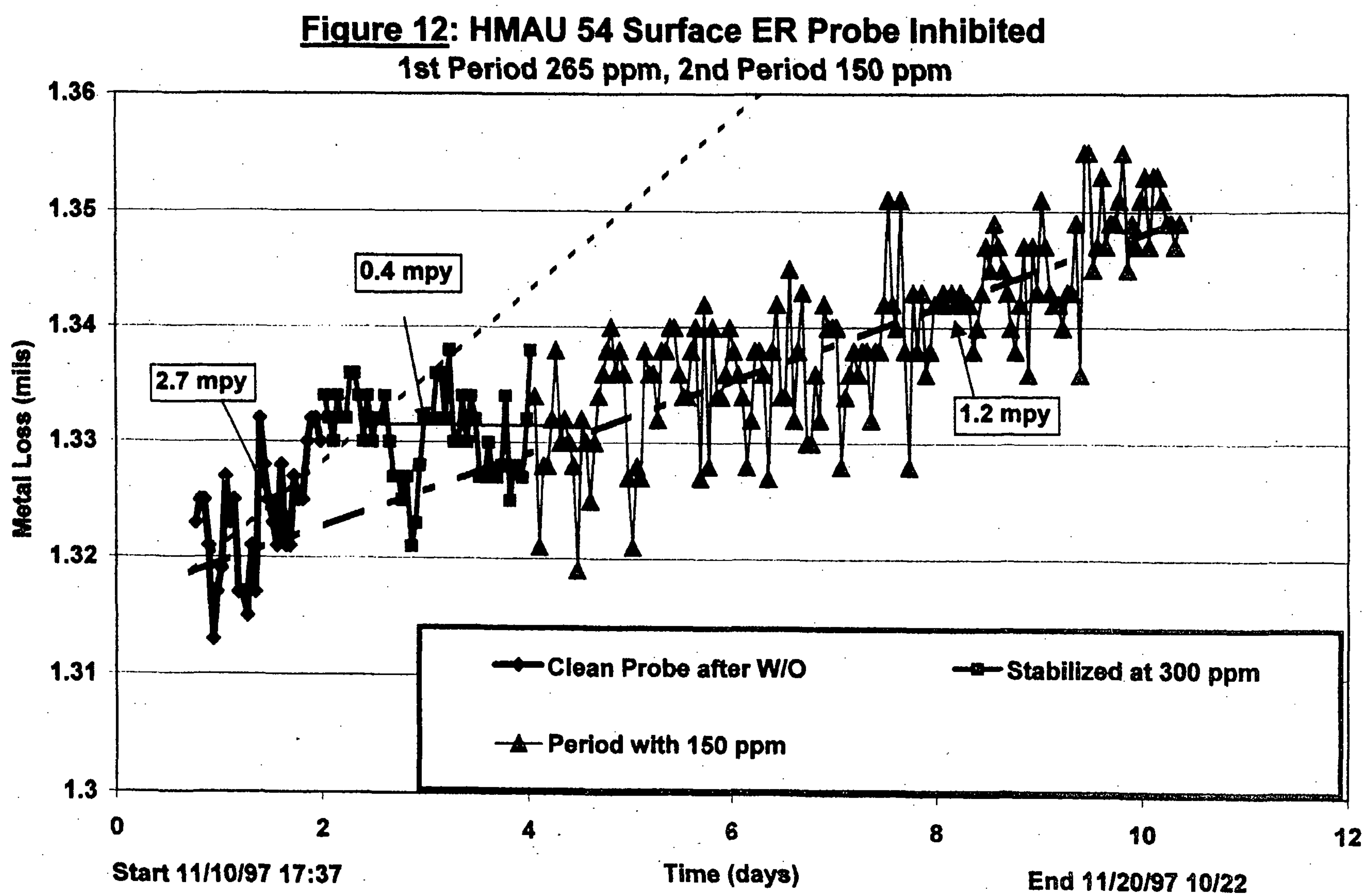


Figure 12: HMAU 54 Surface ER Probe Inhibited
1st Period 265 ppm, 2nd Period 150 ppm
Metal Loss (mils)
1.36
1.35
1.34
1.33
1.32
1.31
1.3
0
2
4
6
8
10
12
0.4 mpy
2.7 mpy
1.2 mpy
Clean Probe after W/O
Stabilized at 300 ppm
Period with 150 ppm
Start 11/10/97 17:37
Time (days)
End 11/20/97 10/22

**Figure 13**: HMAU 54 Surface LPR Corrosion Monitor

Blank Period and Inhibited at 265 and 150 ppm

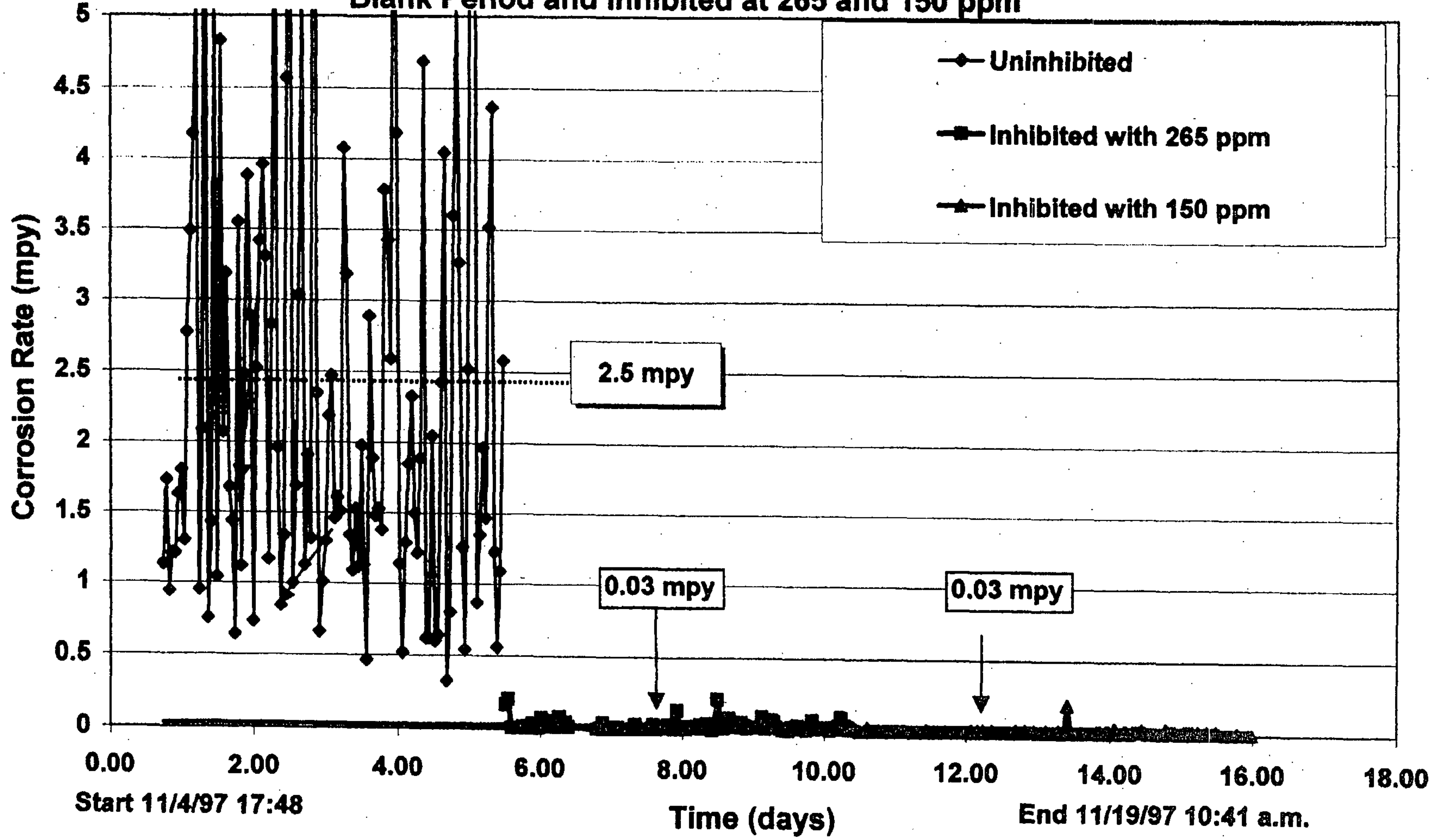


Figure 14: RPM as function of Shear Stress for Rotating Cage
(Empirical fit to calculated data points)

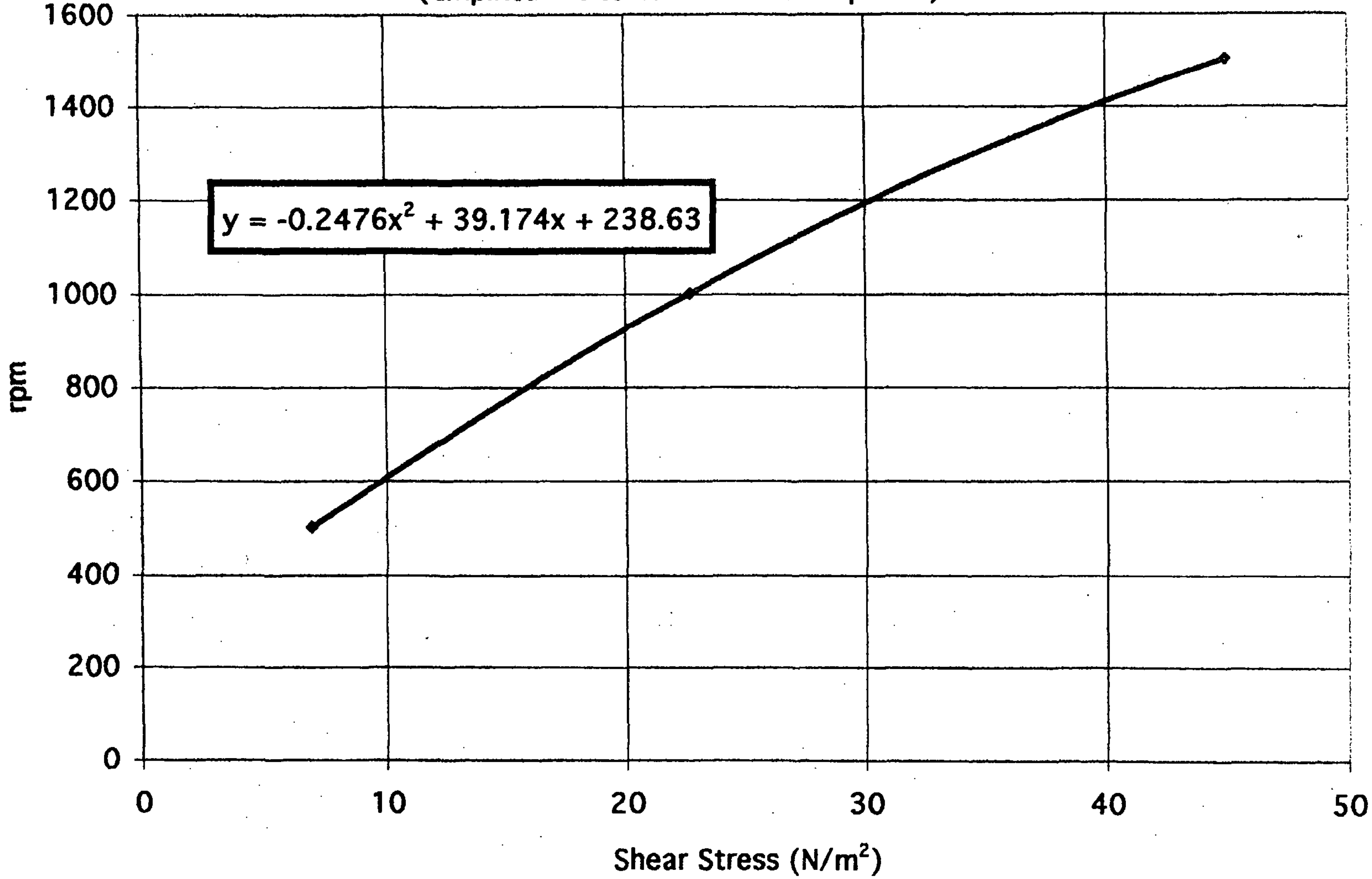
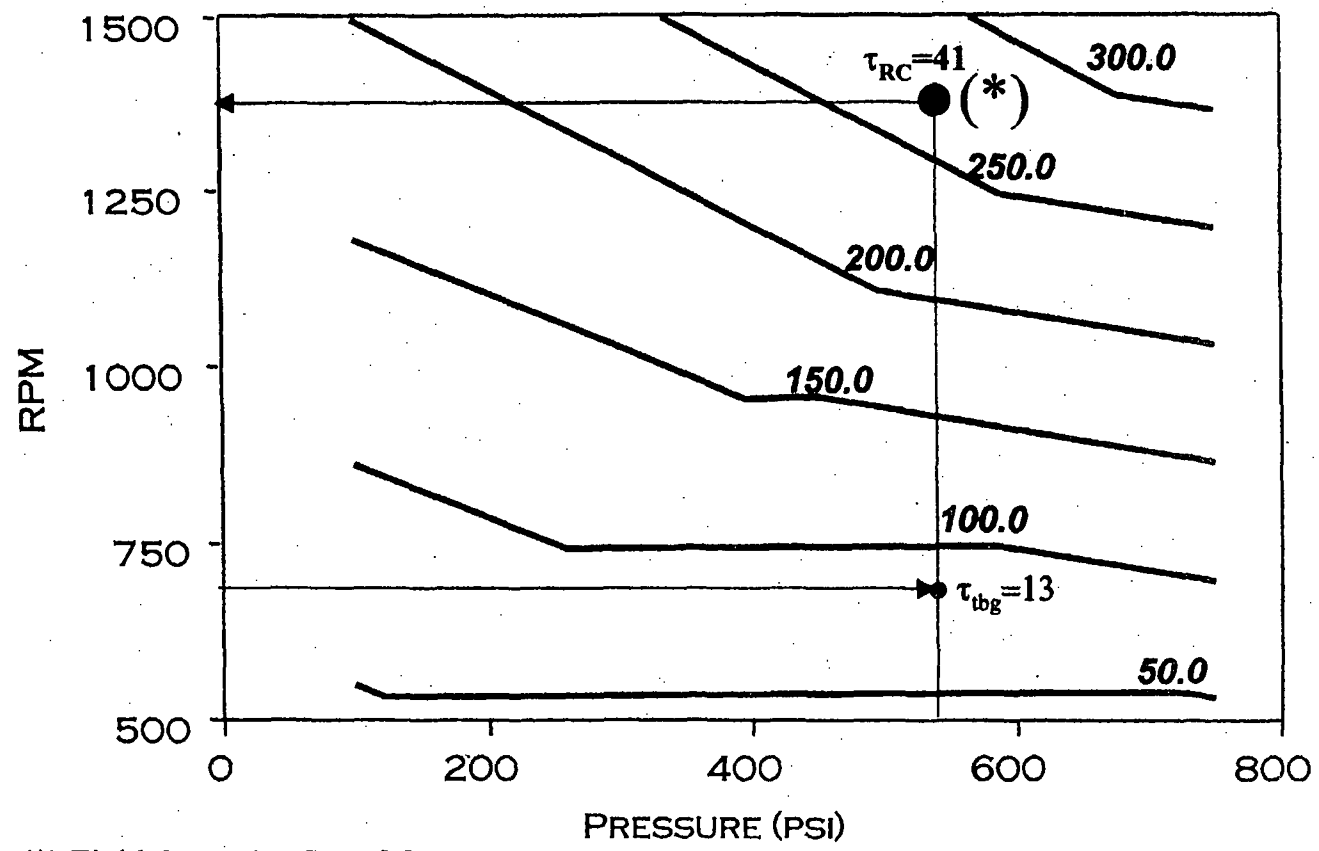
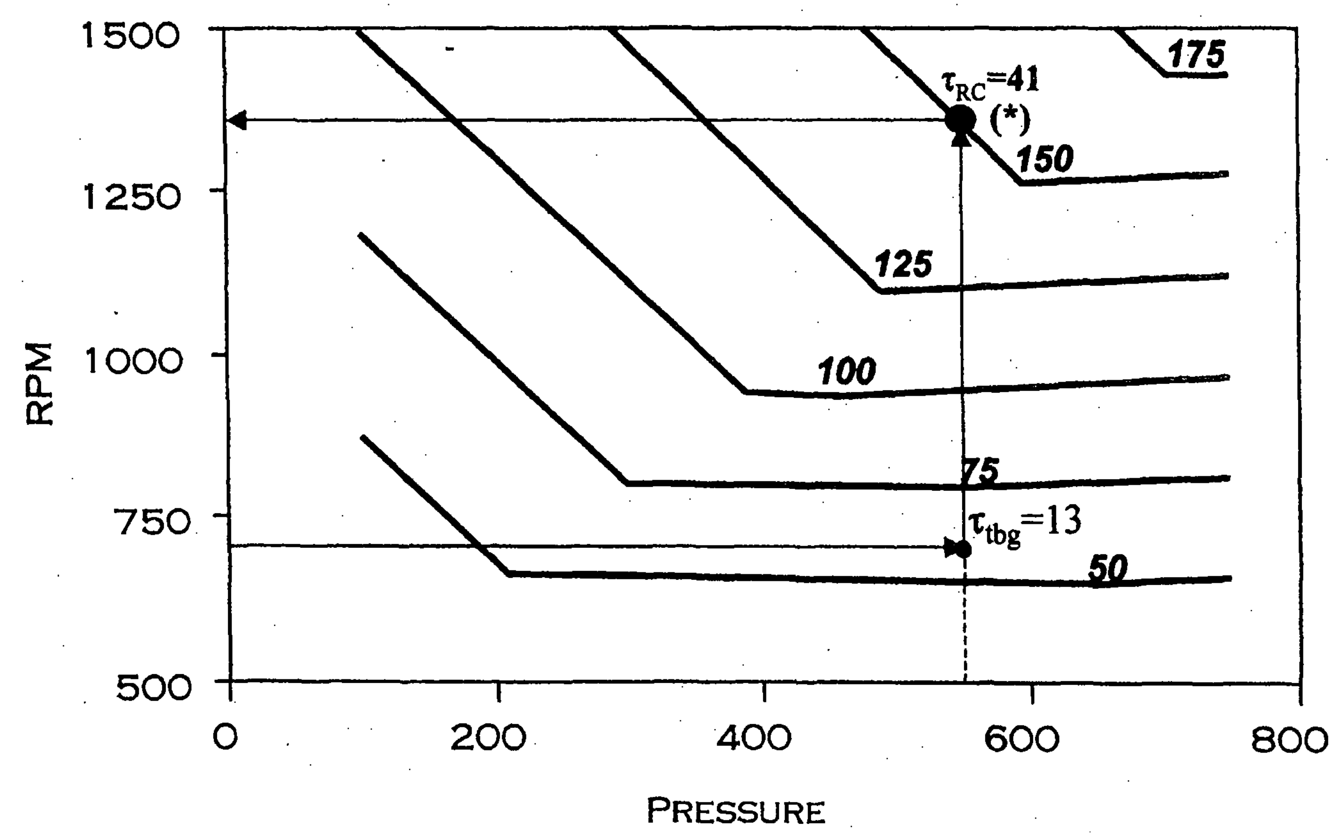


**Figure 15: Contour Plot for Constant Effective Inhibitor Concentration Necessary to Achieve 1 mpy Target Corrosion Rate on J-55**




(*) Field Corrosion Rate Measurement

**<u>Figure 16</u>: Contour Plot for Constant Effective Inhibitor (C) Concentration Necessary to Achieve 4 mpy Target Corrosion Rate on J-55**




(*) Field Corrosion Rate Measurement

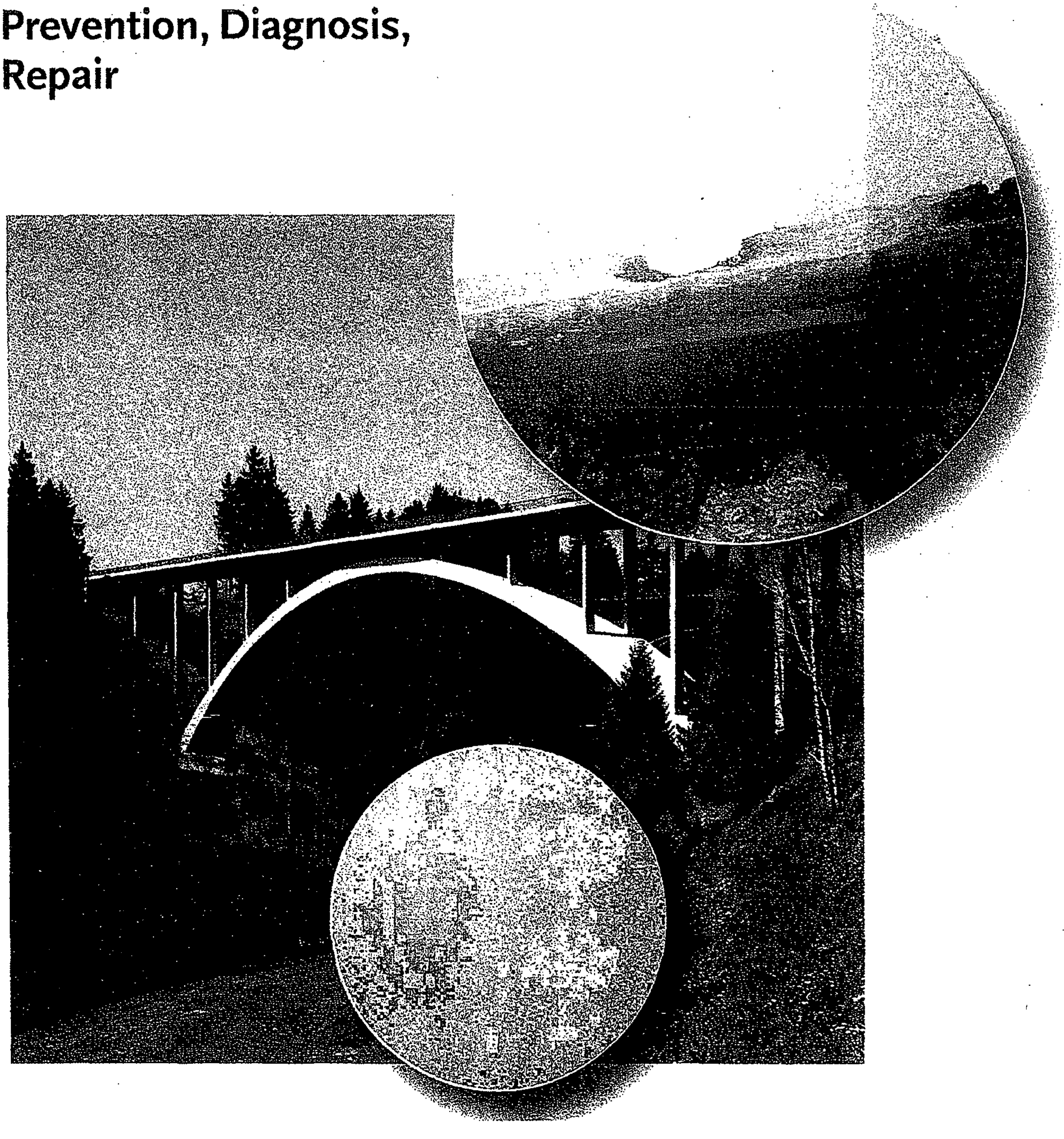
APPLICANT'S EXHIBIT 60

Luca Bertolini, Bernhard Elsener
Pietro Pedeferri, Rob Polder

WILEY-VCH

# Corrosion of Steel in Concrete

## Prevention, Diagnosis, Repair



by BSA. This stimulated new research into the biological origins [13], the identification [14], the influence of concrete composition [15] and possible countermeasures. Some aspects will be treated here briefly.

Anaerobic conditions can occur in sewers due to long retention times of wastewater, e. g. unexpectedly due to uneven settlement, as illustrated in Figure 3.3; wastewater in (completely filled) pressure mains becomes anaerobic after being transported for a few hours. Liberation of the $H_2S$ formed is subsequently promoted by turbulent overflow of anaerobic sewage into aerobic parts of the system. Various types of thiobacilli develop colonies on the concrete surface, which have increasing tolerance for acidic conditions. The final type in this series is thiobacillus thiooxidans (also called concretivorus), which is able to produce (and survive) sulfuric acid with concentrations up to 10 % by mass with a pH below 1. The cement matrix is converted by the reaction with the acid to mainly gypsum and eventually, the converted layer of concrete falls off. Exposure testing for three years in sewers at Rotterdam showed that the rate of attack can be as high as 3 mm per year, with insignificant differences between (both very dense) Portland and blast furnace slag cement concrete [14]. However, high alumina cement showed superior behaviour [16]. A particular sewer system can be tested for BSA by measuring the oxygen and sulfide contents of the wastewater and the pH of the concrete surface (using colour-indicator solutions). The presence of turbulent overflows must be checked and the sewage temperature taken into account [14]. Avoiding long retention times is the best preventative design strategy. Adding oxygen, hydrogen peroxide or nitrate to sewage in order to counteract anaerobic conditions has been successful. In some cases, increasing the flow by connecting rain drainages solved the problem. In large sewer pipe elements, protection of concrete by polymeric sheeting placed in the mould prior to concrete casting is used as a preventative measure.

### 3.2.3
### Attack by Pure Water

Pure water, that is water with a low amount of dissolved solids, in particular calcium ions, acts aggressively towards concrete because it tends to dissolve calcium compounds. If the water flow rate is high, hydrolysis of hydration products continues, because the solution in contact with the concrete is continually being refreshed. Initially, calcium hydroxide, the most soluble component of cement paste, is removed. Then other components are attacked, producing a more open matrix, making the concrete more penetrable to further attack by aggressive solutions. Eventually this will have a deleterious effect on its strength. In the presence of cracks or construction defects, water can more easily percolate through the concrete, aggravating the aforementioned processes.

The degree of the attack by pure water depends to a large extent on the permeability of the concrete, but its $Ca(OH)_2$ content also plays an important role. Concrete types with a low level of $Ca(OH)_2$, like blast furnace slag cement concrete, have improved resistance with regard to this type of degradation. In addition to

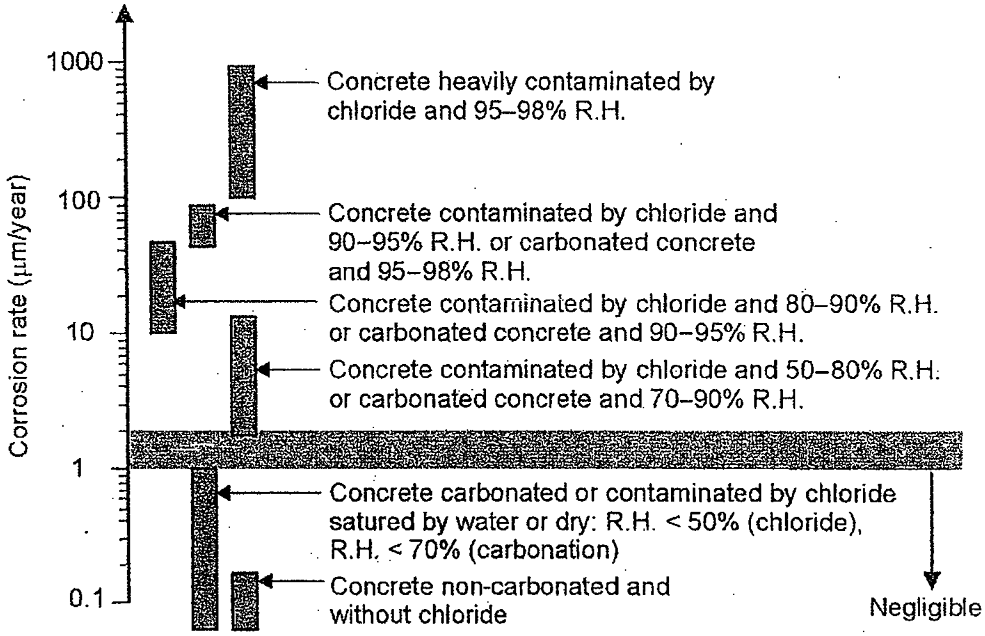



**Figure 4.2** Schematic representation of corrosion rate of steel in different concretes and exposure conditions (after [9], modified)

## 4.3 Consequences

The consequences of corrosion of steel reinforcement do not involve only the serviceability or the external condition of the structure, but may also affect its structural performance, and therefore its safety.

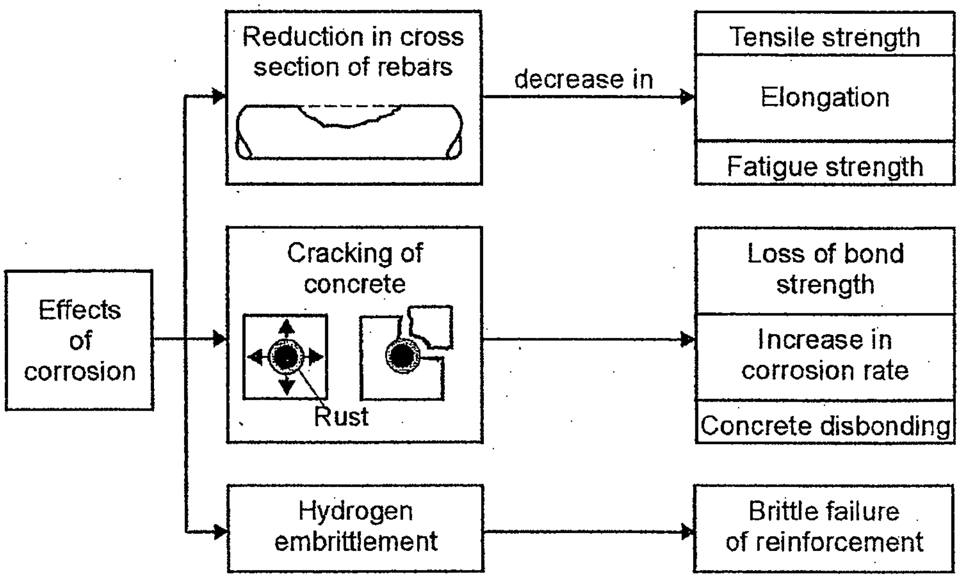



**Figure 4.3** Structural consequences of corrosion in reinforced concrete structures [10]

APPLICANT'S EXHIBIT 61

NUREG-1801, Vol. 2, Rev. 1

# Generic Aging Lessons Learned (GALL) Report

# Tabulation of Results

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Date Published: September 2005

**Division of Regulatory Improvement Programs**
**Office of Nuclear Reactor Regulation**
**U.S. Nuclear Regulatory Commission**
**Washington, DC 20555-0001**

## A1. CONCRETE CONTAINMENTS (REINFORCED AND PRESTRESSED)

### Systems, Structures, and Components

This section addresses the elements of pressurized water reactor (PWR) concrete containment structures. Concrete containment structures are divided into three elements: concrete, steel, and prestressing system.

### System Interfaces

Functional interfaces include the primary containment heating and ventilation system (VII.F3), containment isolation system (V.C), and containment spray system (V.A). Physical interfaces exist with any structure, system, or component that either penetrates the containment wall, such as the main steam system (VIII.B1) and feedwater system (VIII.D1), or is supported by the containment structure, such as the polar crane (VII.B). The containment structure basemat typically provides support to the nuclear steam supply system (NSSS) components and containment internal structures.

II CONTAINMENT STRUCTURES
A1 Concrete Containments (Reinforced and Prestressed)

| Item | Link | Structure and/or Component | Material | Environment | Aging Effect/ Mechanism | Aging Management Program (AMP) | Further Evaluation |
|---|---|---|---|---|---|---|---|
| II.A1-1<br><br>(C-08) | II.A1.1-h | Concrete:<br><br>Dome; wall; basemat; ring girder; buttresses | Concrete | Air – indoor uncontrolled or air – outdoor | Reduction of strength and modulus/ elevated temperature (>150°F general; >200°F local) | Plant-specific aging management program<br><br>The implementation of 10 CFR 50.55a and ASME Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of elasticity due to elevated temperature. Thus, for any portions of concrete containment that exceed specified temperature limits, further evaluations are warranted. Subsection CC-3400 of ASME Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 150°F except for local areas, such as around penetrations, which are not allowed to exceed 200°F. If significant equipment loads are supported by concrete at temperatures exceeding 150°F, an evaluation of the ability to withstand the postulated design loads is to be made.<br><br>Higher temperatures than given above may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and this reduction is applied to the design allowables. | Yes, if temperature limits are exceeded |

II CONTAINMENT STRUCTURES
A1 Concrete Containments (Reinforced and Prestressed)

| Item | Link | Structure and/or Component | Material | Environment | Aging Effect/ Mechanism | Aging Management Program (AMP) | Further Evaluation |
|---|---|---|---|---|---|---|---|
| II.A1-2<br><br>(C-01) | II.A1.1-a | Concrete:<br><br>Dome; wall; basemat; ring girders; buttresses | Concrete | Air – outdoor | Loss of material (spalling, scaling) and cracking/ freeze-thaw | Chapter XI.S2, "ASME Section XI, Subsection IWL"<br><br>Accessible areas:<br>Inspections performed in accordance with IWL will indicate the presence of loss of material (spalling, scaling) and surface cracking due to freeze-thaw.<br><br>Inaccessible Areas:<br>Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557). Documented evidence confirms that where the existing concrete had air content of 3% to 6%, subsequent inspection did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation.<br><br>The weathering index for the continental US is shown in ASTM C33-90, Fig. 1. | Yes, for inaccessible areas of plants located in moderate to severe weathering conditions |

II CONTAINMENT STRUCTURES
A1 Concrete Containments (Reinforced and Prestressed)

| Item | Link | Structure and/or Component | Material | Environment | Aging Effect/ Mechanism | Aging Management Program (AMP) | Further Evaluation |
|---|---|---|---|---|---|---|---|
| II.A1-3<br><br>(C-04) | II.A1.1-d | Concrete:<br><br>Dome; wall; basemat; ring girders; buttresses | Concrete | Any | Cracking due to expansion/ reaction with aggregates | Chapter XI.S2, “ASME Section XI, Subsection IWL”<br><br>Accessible Areas:<br>Inspections performed in accordance with IWL will indicate the presence of surface cracking due to reaction with aggregates.<br><br>Inaccessible Areas:<br>As described in NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54 or ASTM C227-50 can demonstrate that those aggregates do not react within reinforced concrete. For potentially reactive aggregates, aggregate-reinforced concrete reaction is not significant if the concrete was constructed in accordance with ACI 201.2R.Therefore, if these conditions are satisfied, aging management is not necessary. | Yes, if concrete was not constructed as stated for inaccessible areas |

II CONTAINMENT STRUCTURES
A1 Concrete Containments (Reinforced and Prestressed)

| Item | Link | Structure and/or Component | Material | Environment | Aging Effect/ Mechanism | Aging Management Program (AMP) | Further Evaluation |
|---|---|---|---|---|---|---|---|
| II.A1-4<br><br>(C-03) | II.A1.1-c | Concrete:<br><br>Dome; wall; basemat; ring girders; buttresses | Concrete | Ground water/soil or air-indoor uncontrolled or air-outdoor | Increase in porosity and permeability, cracking, loss of material (spalling, scaling)/ aggressive chemical attack | Chapter XI.S2, "ASME Section XI, Subsection IWL".<br><br>Accessible Areas:<br>Inspections performed in accordance with IWL will indicate the presence of increase in porosity and permeability, surface cracking, or loss of material (spalling, scaling) due to aggressive chemical attack.<br><br>Inaccessible Areas:<br>For plants with non-aggressive ground water/soil; i.e., pH > 5.5, chlorides < 500 ppm, or sulfates <1500 ppm, as a minimum, consider (1) Examination of the exposed portions of the below grade concrete, when excavated for any reason, and<br><br>(2) Periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations.<br><br>For plants with aggressive groundwater/soil, and/or where the concrete structural elements have experienced degradation, a plant specific AMP accounting for the extent of the degradation experienced should be implemented to manage the concrete aging during the period of extended operation. | Yes, plant-specific if environment is aggressive |