UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

April 9, 2007

MEMORANDUM TO: ACRS Members

FROM: Michael Junge, Senior Staff Engineer
Technical Support Staff, ACRS

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS SUBCOMMITTEE MEETING ON THE OYSTER CREEK GENERATING STATION LICENSE RENEWAL APPLICATION, JANUARY 18, 2007 - ROCKVILLE, MARYLAND

The minutes of the subject meeting were certified on April 9, 2007 as the official record of the proceedings of that meeting. A copy of the certified minutes is attached.

Attachment: As stated

cc w/o Attachment: F. Gillespie
C. Santos
S. Duraiswamy

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

April 4, 2007

MEMORANDUM TO: Otto Maynard, Chairman
ACRS Plant License Renewal Subcommittee

FROM: Michael Junge, Senior Staff Engineer
Technical Support Staff, ACRS

SUBJECT: WORKING COPY OF THE MINUTES OF THE ACRS SUBCOMMITTEE MEETING ON THE OYSTER CREEK GENERATING STATION LICENSE RENEWAL APPLICATION, JANUARY 18, 2007 - ROCKVILLE, MARYLAND

A working copy of the minutes for the subject meeting is attached for your review. Please review and comment on them at your earliest convenience. If you are satisfied with these minutes please sign, date, and return the attached certification letter.

Attachments: Certification Letter
Minutes (DRAFT)

cc w/o Attachment: F. Gillespie
C. Santos
S. Duraiswamy

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

MEMORANDUM TO: Michael Junge, Senior Staff Engineer,
Technical Support Staff, ACRS

FROM: Otto Maynard, Chairman
ACRS Plant License Renewal Subcommittee

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS SUBCOMMITTEE MEETING ON THE OYSTER CREEK GENERATING STATION LICENSE RENEWAL APPLICATION, JANUARY 18, 2007 - ROCKVILLE, MARYLAND

I hereby certify, to the best of my knowledge and belief, that the minutes of the subject meeting on January 18, 2007, are an accurate record of the proceedings for that meeting.

Otto Maynard 4/9/2007

Otto Maynard, Date
Plant License Renewal Subcommittee Chairman

Final

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MINUTES OF ACRS PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING
OYSTER CREEK GENERATING STATION
JANUARY 18, 2007
ROCKVILLE, MARYLAND

On January 18, 2007, the Plant License Renewal Subcommittee held a meeting in Room T2B3, 11545 Rockville Pike, Rockville, Maryland, to review the License Renewal Application (LRA) for the Oyster Creek Generating Station (OCGS) and the associated Safety Evaluation Report (SER) with Open Items.

The meeting was open to the public. Mr. Paul Gunter of the Nuclear Information Resource Service and Mr. Richard Webster of the Rutgers Environmental Law Clinic made oral statements following the formal presentations by the applicant and staff. Mr. Michael Junge was the Designated Federal Official for this meeting. The meeting convened at 8:30 am and adjourned at 5:31pm on January 18, 2007.

ATTENDEES:

ACRS MEMBERS/STAFF

Otto Maynard, Chairman
John Sieber, Member
Graham Wallis, Member
Said Abdul-Kahlik, Member
Michael Junge, ACRS Staff
William Shack, Member
Mario Bonaca, Member
J. Sam Armijo, Member
Dana Powers, Member

NRC STAFF/PRESENTERS

D. Ashley, NRR
L. Lois, NRR
H. Ashar, NRR
D. Shum, NRR
T. O'Hara, Region I
D. Hoang, NRR
D. Reddy, NRR
R. De La Garza, NRR
L. Lund, NRR
R. Mathew, NRR
R. Conte, Region I
D. Merzke, NRR
J. Eargle, NRR
K. Hsu, NRR
K. Chang, NRR
M. Mitchell, NRR
V. Rodriguez, NRR
G. Cheruvenki, NRR
D. Coe, OCM
S. Tingen, NRR
J. Davis, NRR
J. Ayala, NRR
J. Fair, NRR
S. Burnell, OPA
J. Lamb, OEDO
S. Ali, RES
P. Buckberg, NRR
L. Tran, NRR
N. Dudley, NRR
M. Morgan, NRR
J. Rajan, NRR
T. Le, NRR

W. Bateman, NRR
C. Sydnor, NRR
C. Ng, NRR
D. Nguyen, NRR
R. Li, RES
M. Modes, Region I
S. Arora, NRR
H. Graves, RES
R. Sun, NRR
A. Pal, NRR
J. Canady, NRR

OTHER ATTENDEES

J. O'Rourke, Exelon
D. Benson, The Press of Atlantic City
T. Quintenz, AmerGen
J. Kandasamy, Exelon
J. Hufnagel, Exelon
C. Wilson, AmerGen
K. Muggleson, Exelon
T. Trettel, AmerGen
G. Harttraft, AmerGen
D. Warfel, Exelon
L. Corsi, Exelon
T. Mscisz, Exelon
A. Ouaou, Exelon
H. Ray, Exelon
S. Schwartz, Exelon
T. Schuster, Exelon
P. Tamburno, AmerGen
R. Benson, AmerGen
J. Petti, Sandia
G. Ritz, First Energy
C. Marks, ISL
R. Rucker, First Energy
R. Webster, Rutgers
J. Laird, Exelon
M. Gallagher, Exelon
A. Polonsky, Morgan Lewis
P. Cowan, Exelon
F. Polaski, Exelon
R. Skelskey, AmerGen
S. Hutchins, AmerGen
S. Rafferty-Czincila, Exelon
C. Myer, SNC
D. Spamer, Exelon
G. Krueger, Exelon
S. Getz, Exelon
D. Barnes, Exelon
M. Miller, Exelon
R. Barbieri, Exelon
J. Camire, Exelon
M. Pruskowski, Exelon
T. Rausch, Exelon
B. Meher, Exelon
M. Hessheimer, Sandia
K. Green, ISL
M. Fallin, Constellation Energy
N, Clunn, Asbury Park Press
J. Zielinski, Congressman Saxton Staff
P. Gunter, NIRS

The presentation slides, handouts used during the meeting, and a complete list of attendees are attached to the office copy of the meeting minutes. The presentations to the Subcommittee are summarized below.

Opening Remarks

Mr. Maynard, Chairman of the Plant License Renewal Subcommittee, convened the meeting and made a few introductory remarks. The purpose of this meeting is to review the LRA submitted by AmerGen for OCGS, the updated SER which closed the open items contained in the draft SER and associated documents with focus on questions that were developed during the October 3, 2006 LRA subcommittee meeting.

Staff Introduction

Ms. Lund, NRR, introduced members of the staff including Dr. Kuo (Acting Director for the Division of License Renewal) and Mr. Ashley (License Renewal Program Manager). Ms. Lund stated that the LRA was submitted in July 2005. Ms. Lund stated that the ACRS Subcommittee had a number of questions following the October 2006 Subcommittee meeting. The Subcommittee requested additional information, specifically about the drywell shell from the applicant as well as results of the inspections that were held in October 2006. Ms. Lund stated that the applicant will present information to address the questions put forward by the committee. Additionally, the staff provided a draft and final report of the analysis of the drywell shell performed at Sandia National Laboratories to support the staffs review. Based on this work, the staff issued an update to the Safety Evaluation Report on December 29, 2006. Ms. Lund also stated that the regional inspectors that were present during the drywell inspections would make a presentation.

Oyster Creek Generating Station License Renewal Application

Introduction

Mr. Gallagher, AmerGen, introduced himself, Mr. Lopriore (Senior Vice President), Mr. Rausch (Site Vice President), Mr. Polaski (License Renewal Manager), Mr. Hufnagel, (Project Licensing Engineer), Mr. Quintenz (Site Lead License Renewal Engineer), and other members of AmerGen staff in attendance.

Agenda

Mr. Polaski, AmerGen, discussed the agenda and stated the focus of the presentation would be on the drywell shell corrosion. The first item on the agenda would be a brief overview of the physical configuration of the drywell and the leak path, then a discussion of the cause and corrective actions of the corrosion, followed by the drywell thickness analysis and descriptions of the sand bed region; embedded portions of the drywell shell; and the upper shell.

Drywell Shell Corrosion Cause and Corrective Actions

Mr. Polaski, AmerGen, described the cause of, and corrective actions implemented to address corrosion of the drywell liner. During refueling outages in the mid-1980's the sand bed drains were clogged and water was found in the sand bed regions. Leaks in the reactor cavity allowed water to flow through the gap between the drywell and the reactor building to the sand bed region. Approximately 1000 ultrasonic (UT) thickness measurements were taken to identify the thinnest locations in the sand bed region and upper elevations. Core samples were also taken to confirm the UT measurements and that the mechanism was general corrosion. A random UT inspection plan was implemented to verify the adequacy of measurement locations. The staff accepted this program in an SER dated November 1, 1995.

The corrective actions implemented in the early 1990s to address this drywell corrosion included: (1) re-analyzing the containment peak pressure to establish additional shell thickness margin; (2) determining the acceptable shell thickness; (3) taking UT measurements to verify minimum thickness with margin; (4) reducing the source of water leakage; (5) removing sand from the sand bed region; (5) clearing the sand bed drains; and (6) coating the drywell shell in the sand bed region. These corrective actions were determined to be effective in 1994 since UT measurements take in 1992 and 1994 confirmed that corrosion in the sand bed region was arrested. Since the UT measurements taken in 1996 contained some uncertainties, additional testing was performed in 2006 to confirm that corrosion has arrested. Mr. Gallagher added that visual inspections of the coating were also performed in 1994.

Mr. Polaski stated that during the 2006 refueling outage the leakage from the reactor cavity liner was estimated to be about 1 gallon per minute and it was captured by the drainage system. UT measurements of the drywell were taken at 19 monitoring locations for the sand bed region and indicated no change in thickness. A visual inspection of the entire epoxy coating was performed and it was determined to be in good condition. No water was found in the sand bed region. UT measurements were taken in 106 locations in 1992 before the epoxy coating was applied. UT measurements performed in the same locations during the 2006 outage showed the drywell shell exceeds design thickness requirements and 13 UT measurements in the upper elevations of the drywell show only 1 location with minimal ongoing corrosion. Based on the corrosion rate, that point will meet minimum required thickness through 2029 with margin.

Drywell Thickness Analysis

Dr. Hardayal Mehta (GE) discussed the Drywell Thickness Analysis which was completed in the early 1990s. Dr. Mehta described the modeling of the drywell including the materials in the drywell shell, the configuration of piping, and the concrete which embeds the drywell liner. He also described the finite element models used. He stated that the symmetry of the model was used so that only a 36 degree section needed to be modeled. The model included the drywell shell from the base of the sand bed region to the top of the elliptical head and included the vent and vent header. He stated that the drywell shell thickness in the sand bed region was assumed to be uniformly 736 mils thick. He described the applied loads as gravity loading consisting of dead weight loads, penetration loads and live loads; design pressure of 62 psi which was later changed to 44 psi through a license amendment in 1993; and seismic loads including inertia loads and relative support displacement.

Using the model described above, Dr. Mehta stated that a bucking analysis was completed and the following conclusions were drawn; the stress limits and safety factors are in accordance with the Code requirements; the analysis shows that the drywell shell meets the ASME Code Case N-284 requirements considering all design basis loads and load combinations; a locally thinned 12 inch by 12 inch area (to 536 mils) was evaluated and determined to have no significant impact on buckling; and the drywell shell thickness will be monitored using 736 mils as the acceptance criteria for the minimum required general thickness and 536 mils as the minimum required local thickness.

Dr. Mehta concluded that the stress analysis of the drywell shell was conducted in accordance with ASME Code and SRP 3.8.2 using reduced thicknesses due to corrosion; that the stress limits and safety factors are in accordance with ASME Code requirements; that the drywell shell meets ASME Code Stress requirements considering all design basis loads and load combinations; and that the drywell shell thickness will be monitored for corrosion using the calculated minimum required general and local thicknesses as acceptance criteria.

Sand Bed Region

Mr. O'Rourke discussed the background, history and recent inspections of the sand bed region. He stated that UT measurements were taken between 1983 and 1986 to identify the thinnest locations. These locations were used to develop the points for the corrosion monitoring grid points. He stated that at least one grid is located in each of the 10 bays. Mr. O'Rouke also stated that two trenches were excavated to determine the extent of the corrosion in the sand bed region below the drywell interior floor. Mr. O'Rourke stated that in 1992 the sand was removed from the sand bed region and the shell was cleaned. External UT measurements were taken in all bays at the thinnest region as determined by visual inspection. The shell was then coated with an epoxy coating which was designed to be used on corroded surfaces.

Mr. Cavallo (Corrosion Control Consultants and Labs, Inc.) Stated that the OCGS protective coatings monitoring and maintenance program is consistent with NUREG 1801, Rev. 1 (GALL). This program includes the coating service level II coatings applied to the exterior of drywell in the sand bed region. Mr. Cavallo stated that the inspections and evaluation of the coatings is conducted in accordance with ASME Section XI, Subsection IWE by qualified VT inspectors. He stated the premise of the Code is that degradation of a steel substrate will be indicated by the presence of visual anomalies in the attendant protective coating. He concluded that with periodic condition assessment and maintenance (if required), the OCGS sand bed region coating system will continue to prevent corrosion on the steel substrate for the period of extended operation and that a 10 year inspection periodicity cycle is appropriate and commensurate with the sand bed region environment and industry experience.

Mr. Tamburo discussed the background and history of the UT thickness measurements in the sand bed region. He discussed the statistical methodology used to determine the inspection periodicity of future UT measurements. Mr. Tamburo concluded that the corrosion on the outside of the drywell shell in the sand bed region has been arrested and there is sufficient margin to the minimum thickness requirement.

Mr. Ray (AmerGen) discussed the 2006 Inspections performed in the sand bed region. He stated that visual inspection of the coatings occurred in all 10 bays, that UT measurements were taken of 19 grid locations at the 11' 3" elevation and that 106 UT measurements were taken at locally thinned single point locations on the outside of the drywell shell. He stated the visual inspections of the coating identified no degradation, and the 19 grid location UT measurements did not identify ongoing corrosion. The 106 external UT measurements taken were not directly comparable to the 1992 results due to differences in measurement techniques. Based on these results, Mr. Ray concluded that corrosion on the outside of the drywell shell in the sand bed region had been arrested, the epoxy coating did not show indications of degradation, and there is sufficient margin to the minimum thickness requirement.

Embedded Portions of the Drywell Shell

Mr. O'Rourke described the lower drywell support structure including the sandbed, trenches and sump. He stated that any corrosion of the drywell exterior embedded surface occurred because of water leakage into the sand bed region. He stated that the corrective actions for the sand bed region arrested the corrosion of the drywell exterior embedded shell. These corrective actions included preventing water leakage into the sand bed region, and sealing the joint between the drywell shell and floor of the sand bed region. Mr. O'Rourke stated that the water identified in the trenches in bays 5 and 17 inside the drywell discovered during the 2006 refueling outage was determined to have originated from equipment leakage inside the drywell. He stated corrective actions made during the 2006 refueling outage included caulking the joint between the drywell interior floor and the drywell shell and repairs were made to the collection trough in the sub pile room.

Mr. Gordon (Structural Integrity Associates, Inc.) discussed the corrosion of steel embedded in concrete. He stated the high pH environment created during the concrete pours results in a passive, protective film on the carbon steel surface that mitigates corrosion in the absence of an aggressive environment. He stated the chemistry of the water leachate from the sand bed region measured in 1986 revealed high purity water, and per GALL, this water is not aggressive to the embedded steel in concrete.

Mr. O'Rourke discussed the 2006 refueling outage visual and UT inspection results. He stated that the 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. He stated that UT inspections were performed on the excavated portion of the trench in bay 5 and 106 individual measurements were made from the exterior of the sand bed region. Mr. O'Rourke concluded that corrosion on the embedded surfaces of the drywell shell, both interior and exterior, is not significant and is estimated to be less than 1 mil per year which allows the drywell shell to meet code thickness requirements, with margin, to 2029. He also stated that UT measurements will be repeated in 2008 to verify these conclusions.

Upper Drywell Shell

Mr. O'Rourke described the upper drywell shell region and the UT inspections that have been performed. He stated that over 1000 UT measurements have been taken to locate areas of corrosion on the exterior surface and based on the results, 13 grid locations were selected for monitoring every other refueling outage. He stated that the 2006 inspection results showed no statistically observable corrosion in 12 of the 13 grids; that the location with the minimum margin has no ongoing corrosion; and that only one location shows a corrosion rate of 0.66 mils per year. Mr. O'Rourke concluded that the measurements taken were lead indicators of corrosion on the outside of the shell, the corrosion rate of the upper shell is less than 1 mil per year, and based on current rates there will be enough margin through the period of extended operation.

Overall Applicant Conclusions

Mr. Polaski summarized the conclusions of the applicants presentation. He stated that 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; and that there is an effective management program in place to ensure continued safe operation.

Staff Presentation

The presentation by Mr. Ashley, NRR, Mr. Ashar, NRR, Mr. Modes, Region I, Mr. Conte, Region I, and Mr. O'Hara, Region I, provided an overview of the regions inspections during the 2006 refueling outage, staff's updated SER, and followed by a discussion on socket welds.

Region I Inspections

Mr. Conte summarized the scope and results of the inspections the Region performed during the fall refueling outage with the focus on the in-service inspection program, the visual examinations of the torus and drywell. Mr. Conte described the key observations/results as all UT results are greater than the calculated minimum code required thickness for various plates that form the drywell shell; no adverse conditions of the epoxy coating on the outside of the drywell shell in the former sandbed region; repairs in and around the trough within the reactor vessel pedestal area did not result in any adverse conditions; and water discovered in the drywell trenches had no adverse impact on the structural integrity of the concrete floor or the potential for corrosion of the embedded portion of the drywell shell. He concluded that no safety significant conditions with respect to the primary containment that would prohibit startup existed and that there was reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle.

Status of Open Items/Commitments

Mr. Ashley stated that the SER with open items was issued on August 18, 2006 with 5 open items and no confirmatory items. A new updated SER was issued on December 29, 2006, which closed the 5 open items with new commitments being incorporated into the updated SER. Mr. Ashley stated that the staff concluded that with the resolution of the open items and additional commitments, there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis.

Structural Integrity Analysis of the Degraded Drywell Containment

Mr. Ashar and Mr. Petti (SNL) discussed the scope and intent of the Sandia National Laboratories Analysis. Mr. Ashar stated that the intent of this study was to assess the ability of the degraded drywell shell to withstand the postulated loadings. This study used a 360 degree model of the drywell and included wall thinning to model degradation. Mr. Ashar stated the analysis concluded that the degradation of the drywell shell in its current state meets the requirements of the ASME Code. He also stated that the applicant has committed to future monitoring of the degradation and evaluation of the integrity of the drywell shell as an going process.

Public Comments

The presentation by Mr. Gunter, Nuclear Information Resource Service, and Mr. Webster, Rutgers Environmental Law Clinic, focused on the issue of drywell shell corrosion.

Mr. Webster described his understanding of the outcome from the previous subcommittee meeting. He stated his understanding to be that the staff must first establish margin for both the sandbed and embedded regions of the drywell shell, and second determine whether that margin can be maintained. He described the key issues from the previous meeting to be that less than 1 percent of the sandbed area was measured and the last good measurements were in 1992 or 1994; that data was fitted to a normal distribution by segmenting and editing out the pitted areas; that acceptance criteria was based on modeling of idealized geometries; that 0.064 inches is a claimed margin, and not real; that the visual assessment of the coating was inadequate; that there needs to be better detection of corrosive conditions and a faster response to those conditions; and that no measurements were taken in the embedded region.

Mr. Webster discussed his review of the 2006 external UT results, possible causes of thinning, how the applicant determines margin and that margin does not exist but if margin did exist, the applicant could not maintain the margin, and finally the embedded region measurements. He stated his conclusions were that margin in the sandbed region ranges from 0.04 inches to less than zero; that there is significant probability that there is no current margin in the sandbed region; that if margin is 0.04 inches, it is too small to maintain because of the uncertainty in measurements and corrosion rates; and that the margin in the embedded region is unknown.

Member Comments

General

Dr. Bonaca's comments: Dr. Bonaca felt the presentation provided an assertion that the corrosion has been stopped and that the drywell can operate until 2029. He would like to hear the monitoring program discussed in more detail at the full committee meeting. He would like to see a more aggressive short term inspection program but also thinks waiting for ten years to do the inspections again is too long a time period to wait. He raised the issue of controlling sources of water several times. He questioned whether the applicant has done as much as they can to control the sources of water to ensure there is no further accumulation in the drywell. He also questioned whether there was any corrosion taking place behind the epoxy and if the applicant was going to perform UT inspections to identify that there may be some weakness behind the epoxy. Lastly, he questioned how large an area of thinning could be tolerated on the drywell shell and still meet its design.

Dr. Shack's comments: Dr. Shack stated that water in the imbedded region was new information. He was concerned over this and although he fully agreed with the argument that it's a fairly benign environment and the corrosion rates are low, and if the containment didn't have the already substantial corrosion that this one does, he would agree that its probably not a problem. But this is a containment where there isn't a lot of margin. The estimate based on the monitoring done thus far was 41 mils lost and that was less than one mil per year. His calculation shows approximately two mils per year. He felt that there was some data from the imbedded region that could be looked at to understand the corrosion rates in the imbedded region a little better. He was comfortable that if the epoxy coating was in good condition, that the corrosion on the outside of the drywell shell is arrested, and that visual examination is the appropriate method for monitoring that area. He was not totally convinced with the small margins that exist that the corrosion in the imbedded region is as negligible. He felt the legalistic requirements of which buckling analysis, AmerGen/GE or Sandia, to accept needed to be settled. He would like to hear more discussion on this subject during the full committee meeting. He also felt that the details of each analysis should be discussed to identify if it was appropriate to use a modified reduction capacity factor or since the current margin is small, was it appropriate to use a uniform thinning model.

Dr. Wallis' comments: Dr. Wallis questioned how good the buckling analysis had to be, how close to the limit is too close? He felt the buckling analysis was the most important issue and he wasn't sure if it was adequate.

Dr. Armijo's comments: Dr. Armijo felt the condition of the epoxy was impressive. It has been on the drywell shell for 16 years, and was still in good shape. He felt more analysis needs to be done on the drywell shell using modern methods. This analysis could identify some point at which there will be a thickness that's acceptable based on area of the thinning. For example, would it be acceptable for small areas to be much thinner than large areas. He thought there was some controversy over the GE analysis and use of the capacity factor reduction. He felt that should be reassessed by the licensee to determine if that analysis is still valid. Lastly he stated that identifying the water sources was important and that the sources of water should be eliminated.

Mr. Sieber's comments: Mr. Sieber felt it was important to keep the water away from the steel and that filling in the trench and putting the curb back was important because it's inaccessible. The only time you get to look at it is during refueling outages. He thought there was confusion about the differences between the Sandia model and the General Electric models of the drywell shell buckling analysis. A definitive set of criteria that describes the analysis of record is needed. He felt a more modern method was the better technique and that the ASME code needed to be reconsidered during the analysis. He stated that the ASME refers to the governing authority which is this agency. So the interpretation of the code and the application of it to a specific example like this situation is the agency's responsibility to make. They have to write it down and provide the basis for what it is they're doing and why that's the way that it should be interpreted.

Dr. Abdel-Khalik's comments: Dr. Abdel-Khalik's primary concern pertains to the analysis of record submitted by the applicant and whether it conforms to ASME code requirements specifically as it relates to the modification of the capacity reduction factors and the buckling analysis of the refueling case. He pointed out that GE pie section, 36 degree analysis, Mode 1 buckling result corresponds to a Mode 10 buckling result for a 360 degree calculation, and therefore, one can not expect that result to adequately model the entire behavior of the shell specifically if the lower modes are much more limiting than the higher modes. He was also surprised about the discovery of water between the concrete floor inside the drywell and the inside surface of the drywell, and he felt it would be a good idea not to cover the trench and make sure it is monitored and find out where that water is from and how much of it is there.

Chairman Maynard's comments: Chairman Maynard felt the public comments raised a number of questions and resulted in taking some additional looks at the data and perhaps generated some additional questions for the staff or for the licensee. He did not feel the differences between the GE and the Sandia analysis were significant. He felt it was good to approach some things from different ways. He felt they both showed additional conservatism exist in both of the analyses. They're still very conservative analyses. He felt that the applicant and staff needed to resolve whether the GE analysis that took the capacity adjustments into account is appropriate. His primary concern was that the applicant continued to find water and lived with some leakage. He understood the discussions and the arguments on how it can be managed, but the reality is water should be kept out of the drywell shell area that we don't intend to get there. He felt the trenches should be left open until the staff is sure that water has been eliminated.

Subcommittee Decisions and Follow-up Actions

The Subcommittee Chairman will summarize the discussions at the February 2007 ACRS meeting.

Background Materials Provided to the Committee

1. Updated Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station, December 29, 2006.

2. Safety Evaluation Report with Open Items Related to the License Renewal of the Oyster Creek Generating Station, August 18, 2006.

3. Oyster Creek Generating Station- Application for Renewed Operating Licenses, July 22, 2005.

4. Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application, June 20, 2006.

5. Audit and Review Report for Plant Aging Management Reviews and Programs- Oyster Creek Generating Station August 18, 2006.

6. Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application, November 11, 2005.

7. Oyster Creek Generating Station - NRC License Renewal Inspection Report 05000219/2006007, September 21, 2006

8. Oyster Creek License Renewal Project, Drywell Monitoring Program-Information for ACRS Subcommittee from AmerGen

9. Memorandum dated December 14, 2006 from Louise Lund to John Larkins, Subject: Review Background Materials for the Meeting of the License Renewal Subcommittee Scheduled on January 18, 2007, Related to the Interim Review of the License Renewal of the Oyster Creek Generating Station. ML063470557

10. Memorandum date December 8, 2006 from Michael P. Gallagher to the U.S. Nuclear Regulatory Commission, Subject: Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating

License for Oyster Creek Generating Station. ML063470532

11. Sandia National Laboratories Report "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station," January 2007

12. ASME Code Case N-284-1, "Metal Containment Shell Buckling Design Methods, Class MC, Section III, Division one, March 14, 1995."

13. Letter dated January 31, 2007, from Senator Frank Lautenberg, Senator Robert Menendez, Representative Christopher H. Smith, and Representative Jim Saxton to The ACRS.

14. Letter dated January 31, 2007 from Richard Webster, Rutgers Environmental Law Clinic to the ACRS, regarding the Safety Evaluation Report for Oyster Creek Nuclear Power Plant.

15. Oyster Creek Generating Station-NRC In-Service Inspection and License Renewal Commitment Followup Inspection Report 0500021/2006013, January 17, 2007.

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NOTE:
Additional details of this meeting can be obtained from a transcript of this meeting available in the NRC Public Document Room, One White Flint North, 11555 Rockville Pike, Rockville, MD, (301) 415-7000, downloading on the Internet at http://www.nrc.gov/reading-rm/doc-collections/acrs/ can be purchased from Neal R. Gross and Co., 1323 Rhode Island Avenue, NW, Washington, D.C. 20005, (202) 234-4433 (voice), (202) 387-7330 (fax), nrgross@nealgross.com (e-mail).

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ADAMS DOCUMENT PROFILE
FOR SUBCOMMITTEE MEETING MINUTES

[Required fields in red]

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

December 11, 2006

MEMORANDUM TO: ACRS Plant License Renewal Subcommittee Members

FROM: Michael A. Junge, Senior Staff Engineer
Technical Support Branch, ACRS

SUBJECT: REVIEW MATERIALS FOR THE MEETING OF THE LICENSE RENEWAL SUBCOMMITTEE ON JANUARY 18, 2007 RELATED TO THE INTERIM REVIEW OF THE LICENSE RENEWAL OF THE OYSTER CREEK GENERATING STATION

The purpose of this memorandum is to forward background materials related to the License Renewal Subcommittee Meeting on January 18, 2007 with staff of the Office of Nuclear Reactor Regulation and AmerGen Power Company representatives to continue discussion on the License Renewal Application and Safety Analysis Report of Oyster Creek Generating Station.

To prepare for the meeting, the following documents are attached:

1) Oyster Creek License Renewal Project, Drywell Monitoring Program-Information for ACRS Subcommittee

A Draft Proposed Agenda and Status Report will be sent in the near future.

For additional information, please contact me at (301) 415-6855 or MXJ2@NRC.GOV.

Attachments: As stated

cc: w/o Attachments: J. Larkins M. Snodderly S. Duraiswamy

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 14, 2006

MEMORANDUM TO: John Larkins, Executive Director
Advisory Committee on Reactor Safeguards
and Advisory Committee on Nuclear Waste

FROM: Louise Lund, Branch Chief
License Renewal Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

SUBJECT: REVIEW BACKGROUND MATERIALS FOR THE MEETING OF THE LICENSE RENEWAL SUBCOMMITTEE SCHEDULED ON JANUARY 18, 2007, RELATED TO THE INTERIM REVIEW OF THE LICENSE RENEWAL OF THE OYSTER CREEK GENERATING STATION

The purpose of this memorandum is to forward background materials that may be of assistance to the license renewal subcommittee in preparing for the January 18, 2007 meeting with staff from the Office of Nuclear Reactor Regulation and AmerGen Energy Company representatives. The meeting is being held to continue discussions on the staff's review of the Oyster Creek Generating Station license renewal application.

To prepare for the meeting, the following background materials are enclosed:

1. Index and publicly available documents related to the Oyster Creek Drywell (1966-1996). **ML063470557**
2. Index and publicly available documents related to the inspection of socket welds. **ML063470532**
3. Draft Sandia Report, "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station". **ML063480155**

These documents are available in ADAMS individually or as package number **ML063480014**.

For additional information please contact the project manager, Donnie Ashley at 301-415-3191 or via e-mail at dja1@nrc.gov.

Enclosures:
As stated

mJ

specified in 10 CFR 20.1402. Because the proposed action will not significantly impact the quality of the human environment, the NRC staff concludes that the proposed action is the preferred alternative.

Agencies and Persons Consulted

NRC provided a draft of this Environmental Assessment to the Washington State Department of Health, Office of Radiation Protection for review on October 31, 2006. On November 6, 2006, the Washington State Department of Health, Office of Radiation Protection responded by electronic mail. The State agreed with the conclusions of the EA, and provided editorial comments.

The NRC staff has determined that the proposed action is of a procedural nature, and will not affect listed species or critical habitat. Therefore, no further consultation is required under Section 7 of the Endangered Species Act. The NRC staff has also determined that the proposed action is not the type of activity that has the potential to cause effects on historic properties. Therefore, no further consultation is required under Section 106 of the National Historic Preservation Act.

III. Finding of No Significant Impact

The NRC staff has prepared this EA in support of the proposed action. On the basis of this EA, the NRC finds that there are no significant environmental impacts from the proposed action, and that preparation of an environmental impact statement is not warranted. Accordingly, the NRC has determined that a Finding of No Significant Impact is appropriate.

IV. Further Information

Documents related to this action, including the application for license amendment and supporting documentation, are available electronically at the NRC's Electronic Reading Room at *http://www.nrc.gov/reading-rm/adams.html*. From this site, you can access the NRC's Agencywide Document Access and Management System (ADAMS), which provides text and image files of NRC's public documents. The documents related to this action are listed below, along with their ADAMS accession numbers.

1. NUREG–1757, "Consolidated NMSS Decommissioning Guidance;"
2. Title 10 Code of Federal Regulations, Part 20, Subpart E, "Radiological Criteria for License Termination;"
3. Title 10, Code of Federal Regulations, Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions;"
4. NUREG–1496, "Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities;"
5. NRC License No. 45–23645–01NA inspection and licensing records;
6. Department of the Navy, Termination of Naval Radioactive Materials Permit No. 46–00253–B1NP Issued to Naval Undersea Warfare Center Division, Keyport, Washington, dated October 11, 2005 (ML052970305); and
7. Department of the Navy, Final Status Survey for Naval Undersea Warfare Center and supporting documentation, dated December 15, 2004 (ML060390731).

If you do not have access to ADAMS, or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room (PDR) Reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr@nrc.gov*. These documents may also be viewed electronically on the public computers located at the NRC's PDR, O 1 F21, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852. The PDR reproduction contractor will copy documents for a fee.

Dated at King of Prussia this 5th day of December 2006.

For The Nuclear Regulatory Commission.

Marie Miler,

Chief, Materials Security & Industrial Branch, Division of Nuclear Materials Safety, Region I.

[FR Doc. E6–21355 Filed 12–14–06; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards (ACRS) Meeting of the Subcommittee on Plant License Renewal; Notice of Meeting

The ACRS Subcommittee on Plant License Renewal will hold a meeting on January 18, 2007, Room T–2B3, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

Thursday, January 18, 2007—8:30 a.m. until 5 p.m.

The purpose of this meeting is to continue discussion on the License Renewal Application for Oyster Creek and the associated Safety Evaluation Report (SER) prepared by the NRR staff with emphasis on the containment liner questions raised at the subcommittee meeting held on October 3, 2006. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC staff, AmerGen Energy Company, and other interested persons regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official, Mr. Michael Junge (telephone 301/415–6855) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Electronic recordings will be permitted.

Further information regarding this meeting can be obtained by contacting the Designated Federal Official between 6:45 a.m. and 3:30 p.m. (ET). Persons planning to attend this meeting are urged to contact the above named individual at least two working days prior to the meeting to be advised of any potential changes to the agenda.

Dated: December 11, 2006.

Antonio F. Dias,

Acting Branch Chief, ACRS/ACNW.

[FR Doc. E6–21366 Filed 12–14–06; 8:45 am]

BILLING CODE 7590–01–P

PENSION BENEFIT GUARANTY CORPORATION

Required Interest Rate Assumption for Determining Variable-Rate Premium for Single-Employer Plans; Interest Assumptions for Multiemployer Plan Valuations Following Mass Withdrawal

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Notice of interest rates and assumptions.

SUMMARY: This notice informs the public of the interest rates and assumptions to be used under certain Pension Benefit Guaranty Corporation regulations. These rates and assumptions are published elsewhere (or can be derived from rates published elsewhere), but are collected and published in this notice for the convenience of the public. Interest rates are also published on the PBGC's Web site (*http://www.pbgc.gov*).

DATES: The required interest rate for determining the variable-rate premium under part 4006 applies to premium payment years beginning in December 2006. The interest assumptions for performing multiemployer plan valuations following mass withdrawal

Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee Meeting
Oyster Creek Generating Station
January 18, 2007
Rockville, MD

-PROPOSED SCHEDULE-

Cognizant Staff Engineer: Michael A. Junge mxj2@NRC.GOV (301) 415-6855

Topics	Presenters	Time
Opening Remarks	O. Maynard, ACRS	8:30am - 8:35 am
Staff Introduction	Louise Lund, NRR	8:35 am - 8:40 am
AmerGen - Oyster Creek Presentation A. Drywell Shell Corrosion Overview	 Fred Polaski,	8:40 pm - 9:30 am
B. Drywell Shell Thickness Analysis	Dr. Hardayal Mehta (GE), Ahmed Ouaou	9:30 am - 10:30 am
Break		10:30 am - 10:45 am
C. Drywell Sand Bed Region	John O'Rourke, Jon Cavallo, Pete Tamburro, Howie Ray	10:45 am - 12:00 pm
Lunch		12:00 pm - 1:00 pm
D. Embedded portions of the Drywell Shell	John O'Rourke, Barry Gordon, Howie Ray	1:00 pm - 1:45 pm
E. Upper Drywell Shell	John O'Rourke, Howie Ray	1:45 pm - 2:15 pm
Break		2:15 pm - 2:30 pm
NRC Staff Presentation A. Introduction/Overview	Donnie Ashley, NRR	2:30 pm - 2:35 pm
B. NRC inspection during 2006 outage	Richard Conte, Region I Tim O'Hara, Region I Michael Modes, Region I	2:35 pm - 2:50 pm
C. Status of Open Items / Licensee Commitments	Donnie Ashley, NRR Hans Ashar, NRR	2:50 pm - 3:00 pm
D. Confirmatory Analysis of Drywell - Sandia Model	Hans Ashar, NRR Jason Petti, SNL	3:00 pm - 3:45 pm
E. Socket Welds	Jim Davis, NRR	3:45 pm - 4:00 pm

Public Comment	Paul Gunter (NIRS), Richard Webster (NIRS)	4:00 pm - 5:00 pm
Subcommittee Discussion	O. Maynard, ACRS	5:00 pm-5:30 pm

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE MEETING ON PLANT LICENSE RENEWAL

January 18, 2007
Date

NRC STAFF SIGN IN FOR ACRS MEETING

PLEASE PRINT

	NAME	NRC ORGANIZATION
1	DAN HOANG	NRR/DLR/RLRC
2	Donnie Ashley	NRR/DLR/RLRA
3	JAMES MEDOFF	NRR/DLR/RLRC
4	Michael Modes	RI
5	NOEL DUDLEY	NRR/DLR/RLRA
6	Jim Davis	NRR/DLR/RLRC
7	DUC NGUYEN	NRR/DLR/RLRC
8	ROY MATHEW	NRR/DLR/RLRC
9	Kaihwa R. HSU	NRR/DLR/RLRC
10	P T Kuo	NRR/DLR
11	G.E. Miller	NRR/DORL
12	Hans Ashar	NRR/NRC
13	Louise Lund	NRC/NRR/DLR
14	Harold Chernoff	NRR/ADRO/DORL
15	Ken Chang	NRR/DLR/RLRC
16	MITZI YOUNG	NRC/OGC
17	William B Kennedy	NRR/DPR/PRTA
18	Tommy Le	NRR/DLR/RLRB
19	KAMAL MANOLY	NRR/DE/EEMB
20	Perry Buckberg	NRR/DLR/RLRA

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE MEETING ON PLANT LICENSE RENEWAL

January 18, 2007
Date

NRC STAFF SIGN IN FOR ACRS MEETING

PLEASE PRINT

	NAME	NRC ORGANIZATION
1	MAURICE HEATH	NRR/DLR/RLRA
2	HERMAN GRAVES	RES/DFERR/MSEB
3	ISTAR, ATA	RES/DFERR/MSEB
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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE MEETING ON PLANT LICENSE RENEWAL

January 18, 2007
Date

PLEASE PRINT

	NAME	AFFILIATION
1	Bryan Ford	Entergy
2	PAUL GUNTER	NIRS
3	Jason Petti	Sandia
4	Mike Hessheimer	Sandia
5	William deCamp Jr.	individual
6	David J. Lach	Entergy
7	ALAN Cox	ENTERGY
8	Masato Ando	JAPC
9	MIKE STROUD	ENTERGY
10	April Schilpp	AmerGen
11	Toni Zielinski	Rep. Saxton
12	John Hufnagel	AmerGen
13	RICHARD PEARSON	NMC - PINGP
14	TOM HEDIGAN	NRR/DIRS/IRIB
15	Jason Jennings	NRO/DCIP
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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE MEETING ON PLANT LICENSE RENEWAL

January 18, 2007
Date

PLEASE PRINT

	NAME	AFFILIATION
1	GREG HARTTRAFT	AMERGEN ENERGY
2	Howie Ray	AMERGEN
3	GARY HARLOW	Lehigh Univ.
4	Rachelle Benson	AmerGen
5	Dave Kettering	EXELON\AMERGEN.
6	Kathryn Sutton	MORGAN LEWIS
7	Dan Barnes	AmerGen
8	Jon R. Cavallo	CCC&L INC.
9	Richard Skelskey	AmerGen
10	Peter Tamburro	AmerGen.
11	Barry Gordon	Structural Integrity Associates
12	George Licina	Structural Integrity Associates
13	DAN PAPPONE	GE
14	Thomas Quintenz	AmerGen
15	Ahmed Ouaou	Exelon
16	HAR MEHTA	GE
17	Richard Ciemiewicz	Exelon
18	Mike Gallagher	EXELON/AMERGEN
19	JOHN O'ROURKE	EXELON/AMERGEN
20	FRED POLASKI	EXELON/AmerGen

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE MEETING ON PLANT LICENSE RENEWAL

January 18, 2007
Date

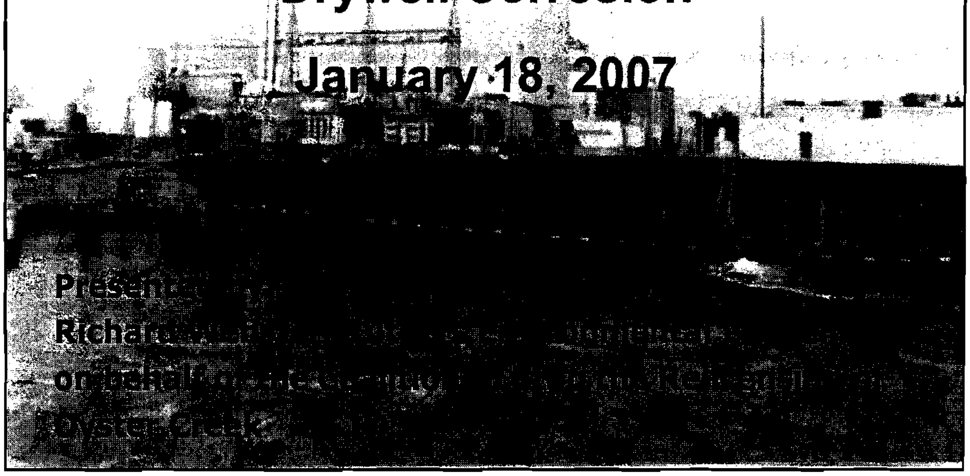
PLEASE PRINT

	NAME	AFFILIATION
1	MICHAEL FALLIN	CONSTELLATION ENERGY
2	Kevin Muggleston	Exelon
3	Alex Polonsky	Morgan Lewis & Bockius LLP
4	Richard Webster	Rutgers Env Law Clinic
5	TIM RAUSCH	EXELON / AMERGEN
6	PAM COWAN	EXELON
7	ROGER STEWART	PROGRESS ENERGY
8	Richard Lopriore	Exelon
9	DON Warfel	EXELON
10	BRAD FEWELL	EXELON
11	Patricia Campbell	GE
12	JOHN DREYFUSS	ENTERGY - VY
13	Steve Bethay	Entergy - Pilgrim
14	Chalmer Myer	SNC
15	JOE ABISAMRA	Entergy - JAF
16	DAVID MANNAI	ENTERGY - Vermont YANKEE
17	Rick Plasse	Entergy - JAF
18	Jim Costedio	Entergy - JAF
19	KAREN TOM	ENTERGY - JAF
20	Richard Schaller	STARS

Oyster Creek Nuclear Generating Station

Unresolved Problems With Drywell Corrosion

January 18, 2007



Outcome of Previous Meeting

- Must put the horse before the cart
- First establish margin for both sandbed and embedded region
  - Significant issues with paucity of data, non-rigorous statistics, large uncertainty, unrealistic modeling, and many cumulative unjustified assumptions
- Second determine whether margin can be maintained
  - Significant issues with equipment failure leading to ongoing leakage, operator failures, uncertainty in the measurements, lack of data to predict corrosion rate, scope & frequency of monitoring

2

Key Issues from Previous Meeting

- Measured < 1% of Sandbed area, last good measurements in 1992 or 1994
- Fitted data to normal distribution by segmenting and editing out pits
- Acceptance criteria based on modeling of idealized geometries
- Margin not established, 0.064 inches claimed
- Visual assessment of coating alone inadequate
- Need better detection of corrosive conditions and faster response
- No measurements in the embedded region

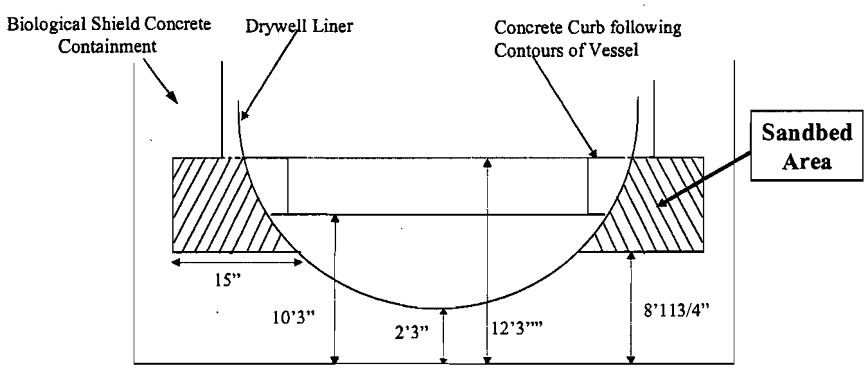
3

What's New

- For sandbed have historic results and new results taken in October 2006
- For embedded region now have a 42 point grid taken in a trench in bay 5 in October 2006
- In October 2006 found water on the inside of the shell below interior floor to be a normal operating condition
- Start with discussion with sandbed

4

Schematic Drawing of Lower Spherical Section of Drywell Liner (not to size)



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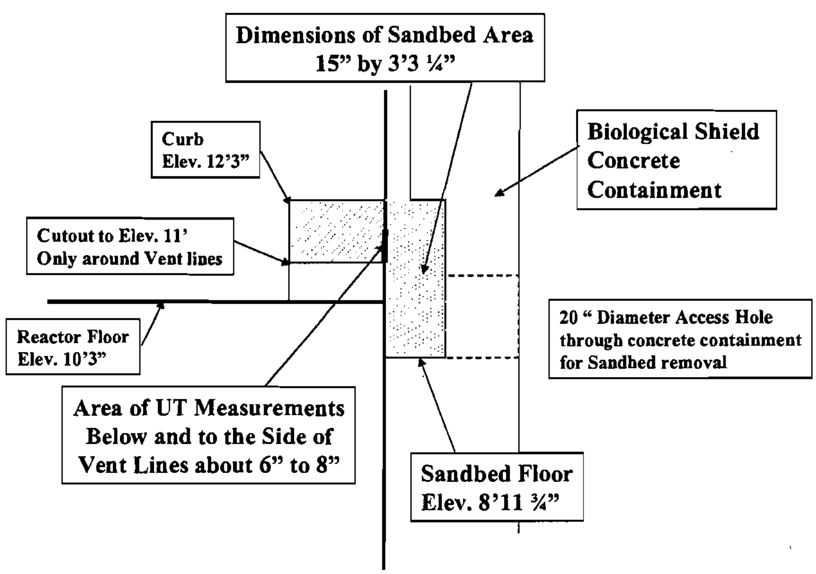
Schematic Cross Section through Sandbed Area
(not to size)



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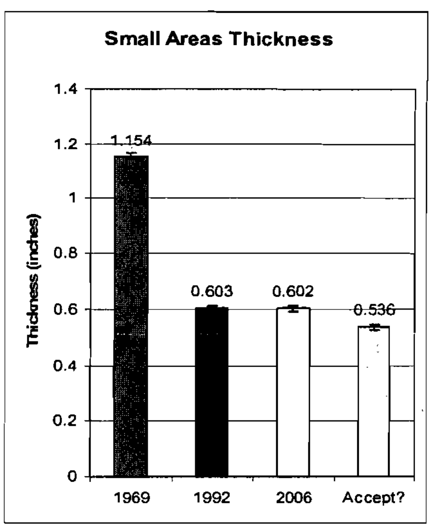
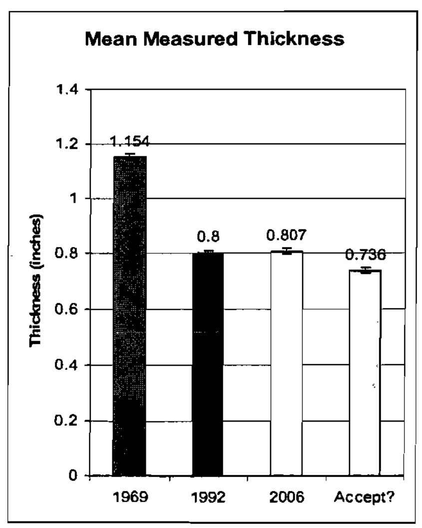
The Sandia Study

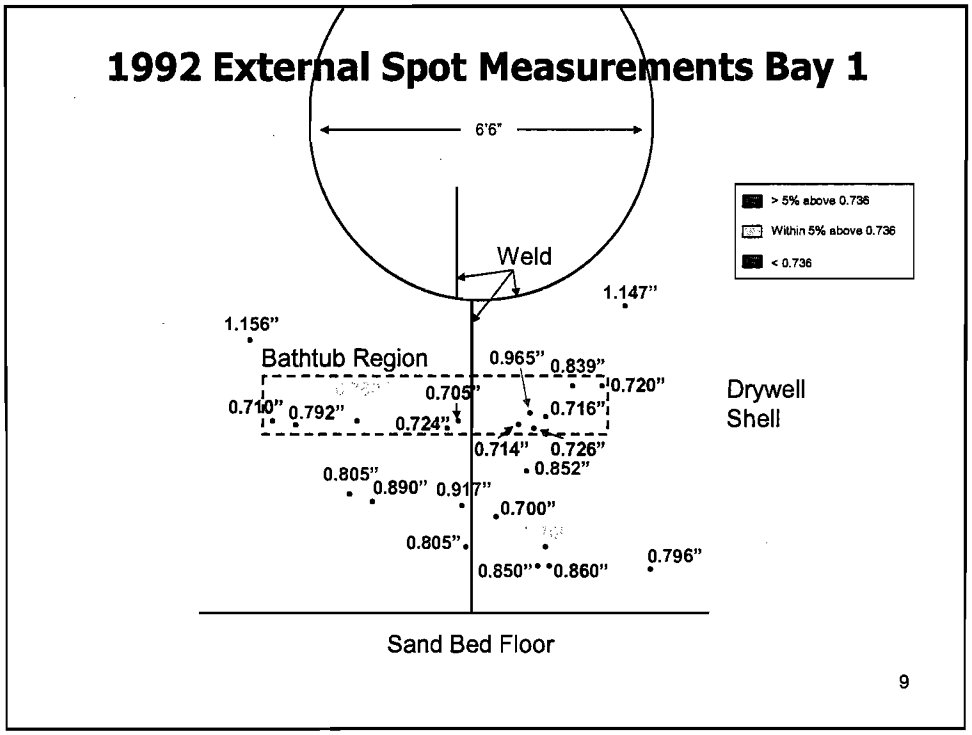
- Sandia model shows:
  - locally thin areas are significant and degradation has caused a 43% reduction in safety factor for the buckling in the sandbed under refueling conditions
  - GE model for buckling under refueling conditions was over optimistic, 0.844 inches uniform thickness needed, not 0.736 inches
  - Under accident conditions bending stress at the transition point at the bottom of the sand bed would be excessive
  - Safety factors for buckling under refueling conditions predicted at 1.95 in the upper drywell and 2.15 in sandbed
- Model fails to take account of measured thinning in the sandbed exterior measurements in October 2006
- Sandi failed to estimate the uncertainty of the prediction of the safety factor or its sensitivity and did not attempt to produce acceptance criteria for future corrosion

7

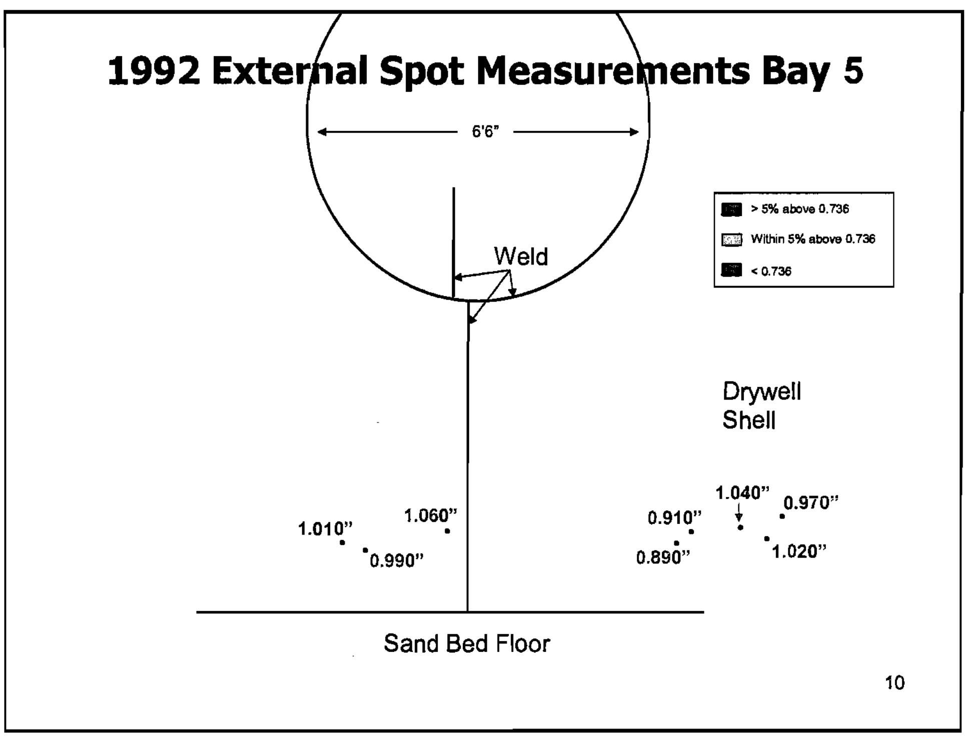
Claimed Safety Margins Based on 6 By 6 Grids





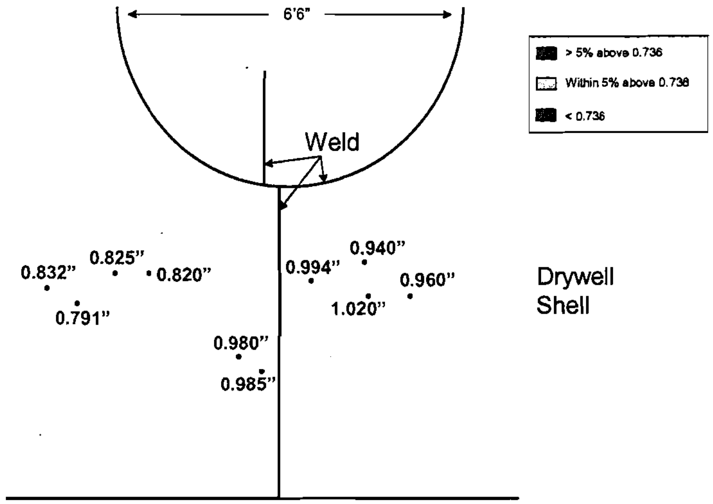


1992 External Spot Measurements Bay 1
6'6"
> 5% above 0.736
Within 5% above 0.736
< 0.736
Weld
1.147"
1.156"
Bathtub Region
0.965"
0.839"
0.720"
0.705"
0.710"
0.792"
0.724"
0.716"
0.714"
0.726"
0.852"
0.805"
0.890"
0.917"
0.700"
0.805"
0.796"
0.850"
0.860"
Drywell
Shell
Sand Bed Floor
9



1992 External Spot Measurements Bay 5
6'6"
> 5% above 0.736
Within 5% above 0.736
< 0.736
Weld
Drywell
Shell
1.040"
0.970"
0.910"
1.020"
0.890"
1.060"
1.010"
0.990"
Sand Bed Floor
10

1992 External Spot Measurements Bay 9



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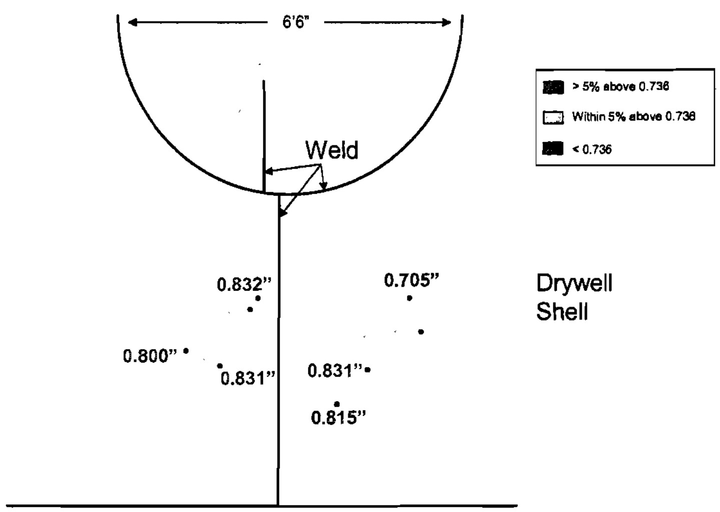
1992 External Spot Measurements Bay 11



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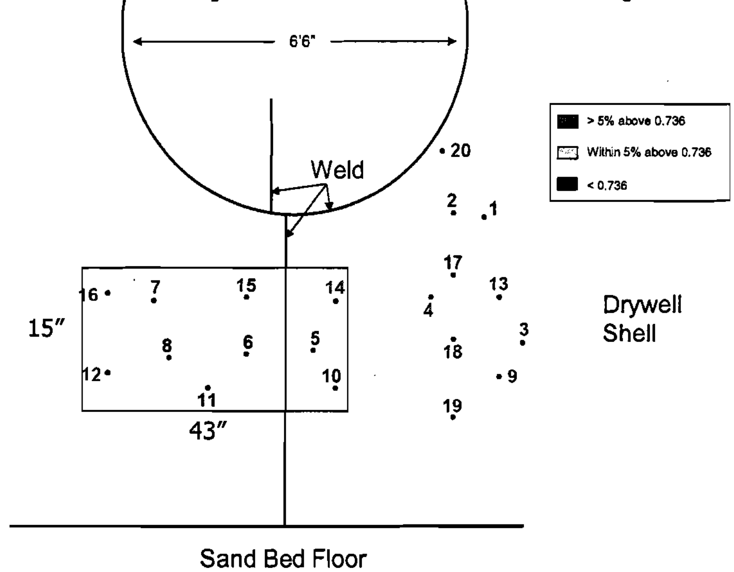
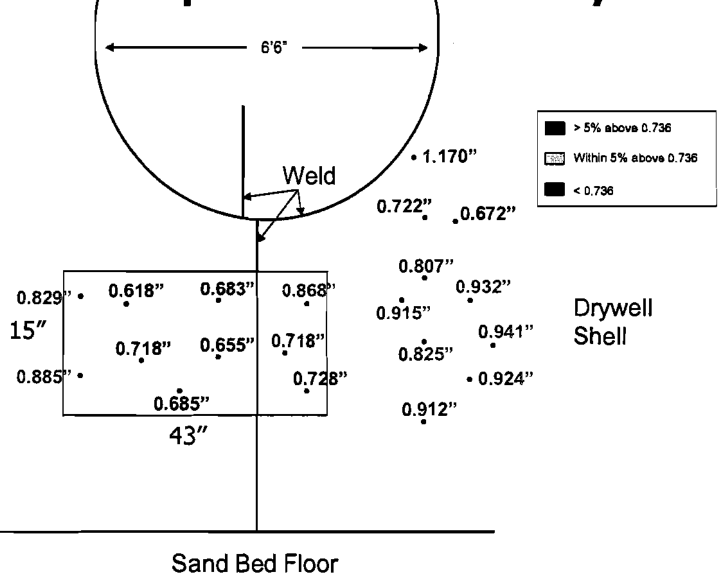
1992 External Spot Measurements Bay 13



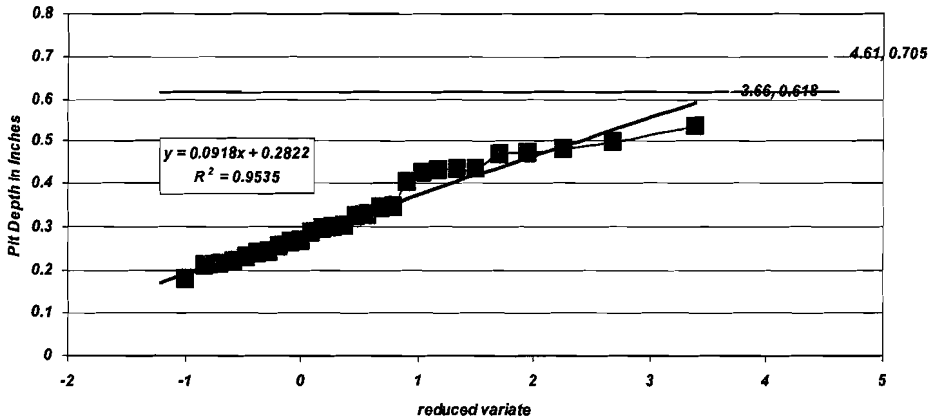
13

1992 External Spot Measurements Bay 13



14

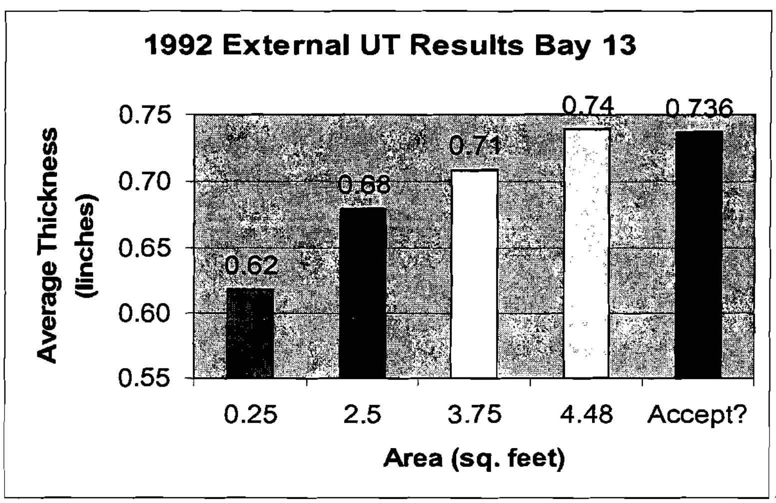
Extreme Value Statistics for 1992 Exterior UT Results in Bay 13



2.5% chance a single point measurement would give thickness less than 0.536"
At 99% certainty shell thickness at each point is > 0.449 inches

15

Significant Thin Areas Existed in 1992



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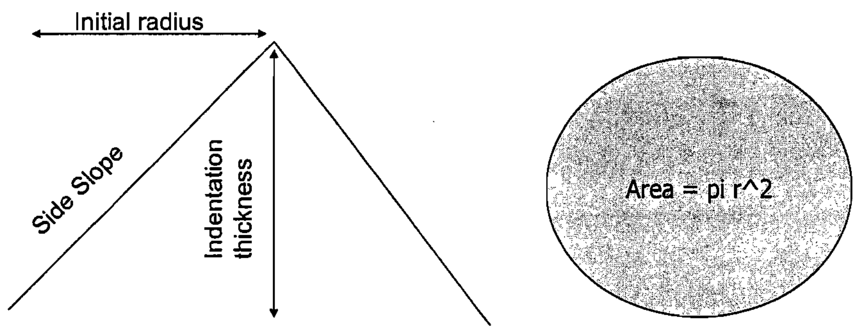
Sensitivity of Area Below 0.736 Inches to Thinning



For illustration assume constant side slope and conical shape
Use known result that Point 7 in Bay 13 has min thickness of 0.618 inches and area below 0.736 inches of 0.25 sq. ft

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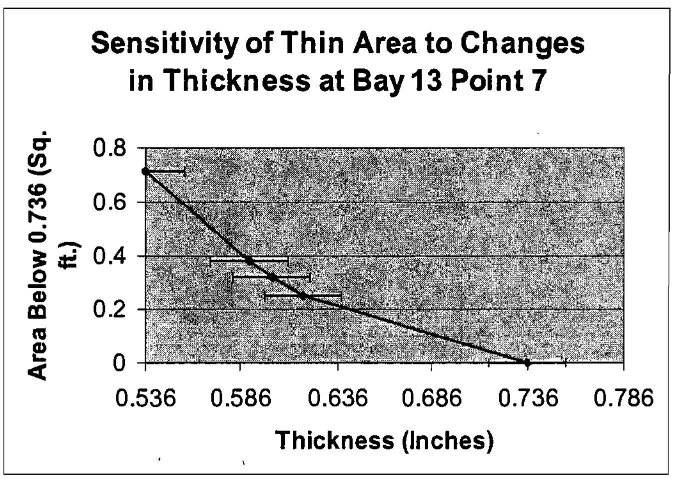
Areas of Thin Regions Are Sensitive to Corrosion



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2006 External UT Results

- Incomplete results presented in an opaque way in ACRS information package
- Thinnest point measured decreased from 0.618 inches to 0.602 inches
- Results indicated general thinning of the drywell shell by up to 0.039 inches
- Likely that shell is thinner than it was in 1992
- Even 0.02 inches of corrosion would be significant because claimed margin was 0.064 inches and thin areas expand quickly with additional thinning

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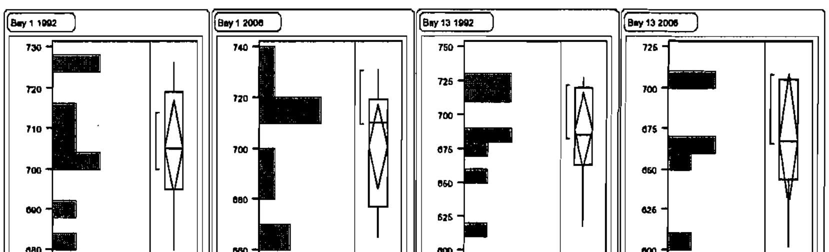
2006 External UT Results: Details



Quantiles

		Bay 1 1992	Bay 1 2006	Bay 13 1992	Bay 13 2006
maximum	100.0%	726.00	731.00	726.00	708.00
	99.5%	726.00	731.00	726.00	708.00
	97.5%	726.00	731.00	726.00	708.00
	90.0%	726.00	730.10	726.00	708.00
quartile	75.0%	719.00	719.75	720.00	705.00
median	50.0%	705.00	710.50	685.00	667.50
quartile	25.0%	695.00	677.25	663.50	644.00
	10.0%	680.00	665.40	618.00	602.00
	2.5%	680.00	665.00	618.00	602.00
	0.5%	680.00	665.00	618.00	602.00
minimum	0.0%	680.00	665.00	618.00	602.00

Moments

	Bay 1 1992	Bay 1 2006	Bay 13 1992	Bay 13 2006
Mean	705.4444	700.9000	688.7778	667.8333
Std Dev	15.0259	23.2113	36.7926	38.3584
Std Error Mean	5.0086	7.3401	12.2642	15.6598
Upper 95% Mean	716.9945	717.5045	717.0593	708.0874
Lower 95% Mean	693.8944	684.2955	660.4962	627.5792
N	9.0000	10.0000	9.0000	6.0000
Sum Weights	9.0000	10.0000	9.0000	6.0000

20

Possible Causes of Thinning

- Systematic measurement error in 1992 – unlikely, major concern if true
- External corrosion occurring despite the preventative measures taken – all coatings were visually inspected as satisfactory, would mean that corrosion could occur when coating is visually intact
- Internal corrosion – water inside the drywell identified as a normal operating condition in October 2006
- Cause of thinning is probably corrosion

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No Margin Left

- Instead of using area acceptance criterion, Exelon has applied point acceptance for exterior measurements without justification
- If area acceptance criterion were applied to external and internal results, the drywell failed in 1992 – worst 0.25 sq ft area measured externally had average thickness of around 0.62 inches, 0.12 inches under 0.736
- Margin failure has increased by around 0.02 inches since 1992, so worst 0.25 sq ft is now around 0.6 inches thick
- If adjust grid criterion to 0.844 inches, 4 of 12 grids fail significantly, and margin is insignificant for 2 others
- Now have no valid acceptance criteria except for 0.844 inches

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Operator Approach To Margin

- 1992 average thickness of Bay 13 estimated at 0.800 inches – not clear how
- Margin was assessed as 0.064 inches by comparing to 0.736 inches uniform thickness prediction
- Bay 13 is now around 0.02 inches thinner
- NRC documents confirm operator also needs to track extent of corroded areas e.g. April 4, 1992 - "In order to consider the corroded area as a discontinuity in NE-3213.10 the extent of the reduction in thickness due to corrosion should be known"
- Sandi cautioned area measured is "limited" and "in many cases, the raw data was not available"

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Operator Cannot Show Margin

- Sandia Model shows a uniform symmetric sandbed at thickness 0.844 inches exactly conforms to code requirements
- Corrosion in Bays 1, 9, 11 and 13 is widespread, are many points thinner than 0.844 inches
- 4 Grids in Bays 11, 17, and 19 show average thinner than 0.844 inches
- In Bay 13, best estimate is that area with average thickness thinner than 0.736 inches is around 4 sq. ft.
- Area thinner than 0.736 inches has probably expanded since 1992
- High degree of uncertainty about the nature of the corroded surface

24

Operator Cannot Maintain Margin

- Even if margin is 0.04 inches, can't rely on visual inspection – could have concealed exterior corrosion or interior corrosion
- Worst sand bed exterior corrosion rate was 0.04 inches/year
- Worst case interior corrosion rate unknown
- Individual measurements have at least 0.02 inches random error, additional location error, and possible additional systematic error

25

E-mail from Ryan to Polaski, dated October 10, 2006

- "The equipment used in the past to perform 'randomly selected' locations did not function worth a 'sh_t', or it didn't perform to expectation
- "Because the locations were not 'stamped or date match marked,' it wouldn't be possible to provide accurate follow up inspections"
- "If you wanted to perform baseline inspections now . . ."

26

Embedded Region

- Sandbed floor damaged when sand was removed
- Floor repaired with epoxy in 1992
- "Since 1996 inspections have found indications of epoxy separating from concrete" and "the separate seams could potentially allow some water to get under the epoxy coating repair" – AmerGen October 25, 2006
- Separation "could be caused by concrete swelling"
- Bottom of drywell is below the groundwater table
- Embedded region corrosion observed at Beaver Valley
- Drilled holes in interior concrete floor at Dresden to take UT measurements
- SER – could get a semi-quantitative assessment using guided wave technology

27

Embedded Region Measurements

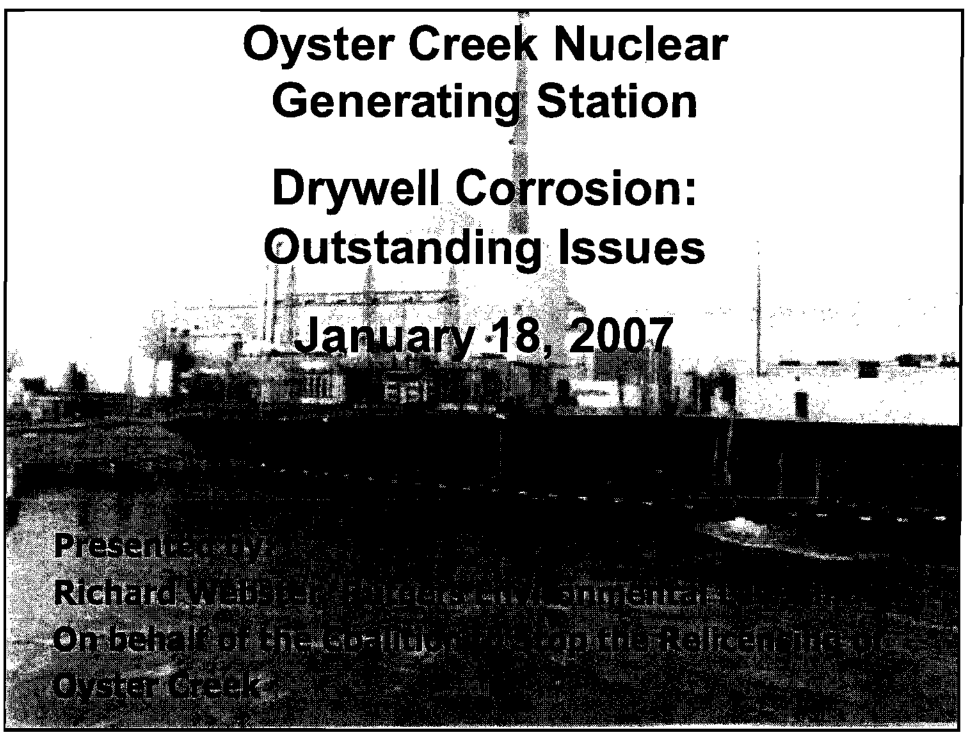
- First measurements taken in Bay 5 in Oct. 2006
- Grid of 42 measurements showed loss in thickness of 0.041 inches
- Corrosion in the embedded region has occurred
- Corrosion in Bay 5 is not bounding - Bay 5 was one of the least corroded bays in the sandbed region
- Shows need for measurement in most corroded bays and for monitoring of conditions in the embedded region
- No assurance of margin at present

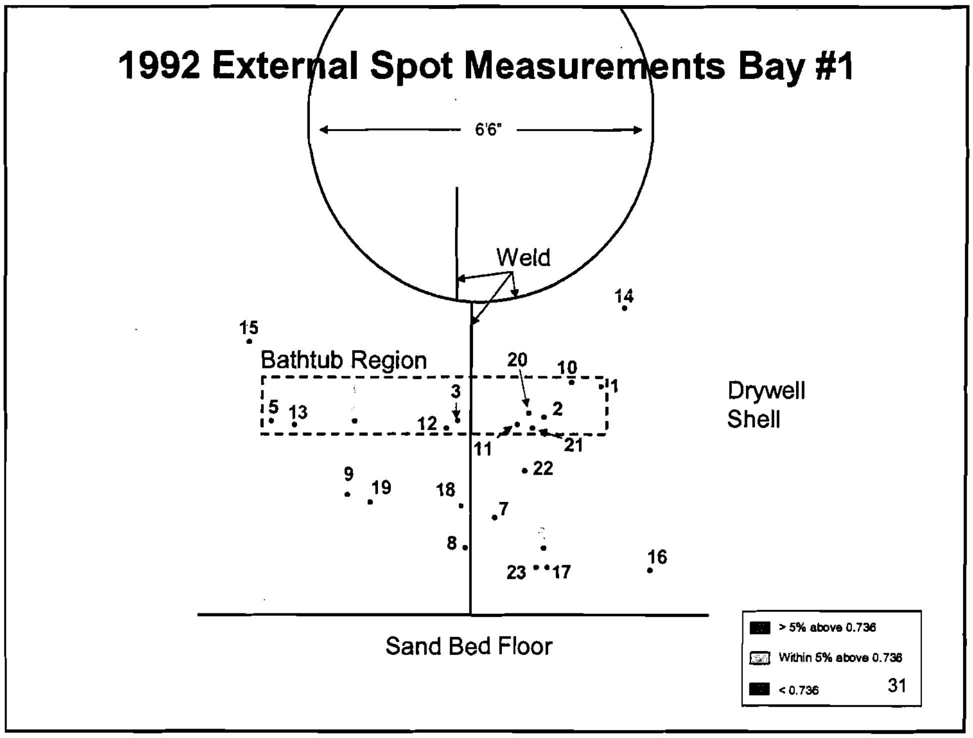
28

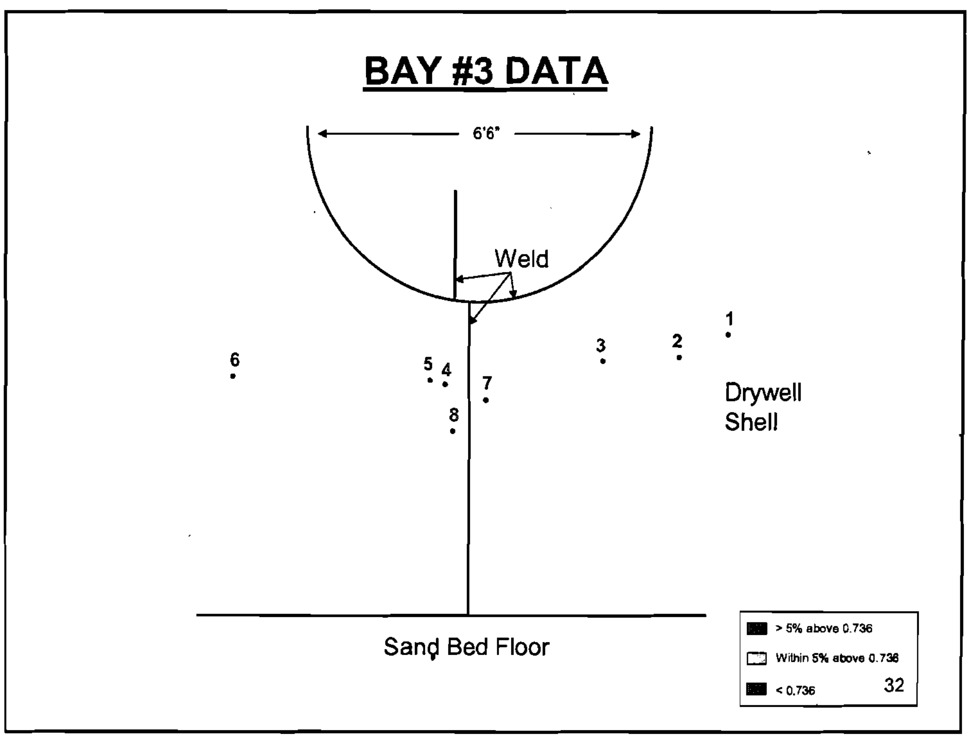
Conclusion

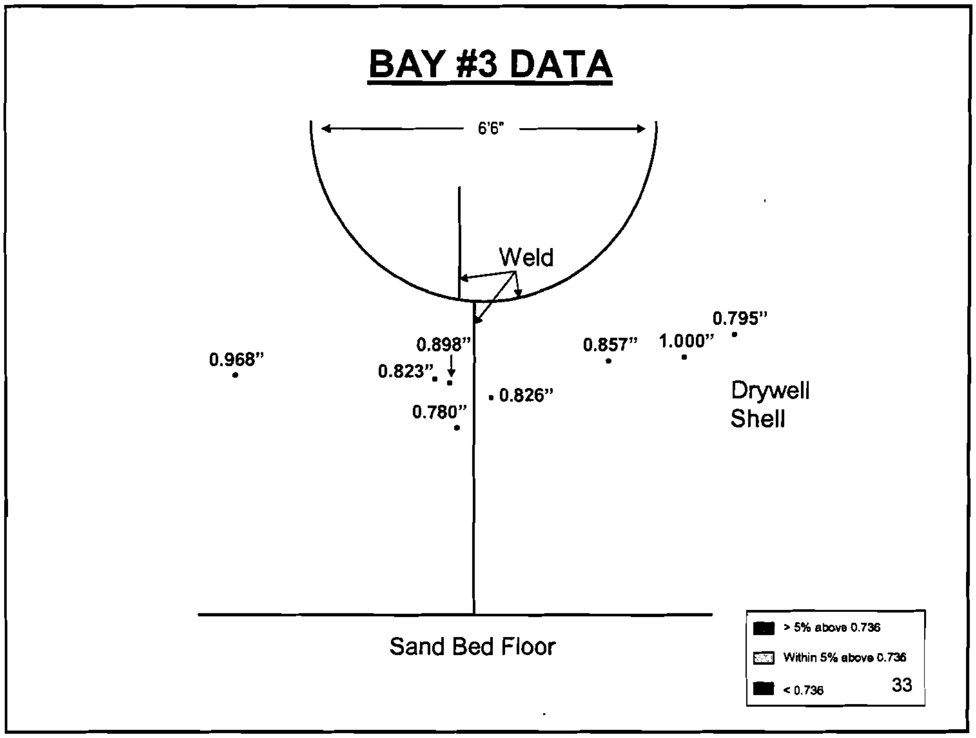
- Margin in the sandbed region ranges from 0.04 inches to less than zero
- There is a significant probability that there is no current margin in the sandbed region
- Err on the side of caution – safety at stake and Exelon has created uncertainty by failing to monitor adequately
- Even if margin is 0.04 inches, it is too small to maintain because of uncertainty in measurements and corrosion rates
- Margin in embedded region is unknown

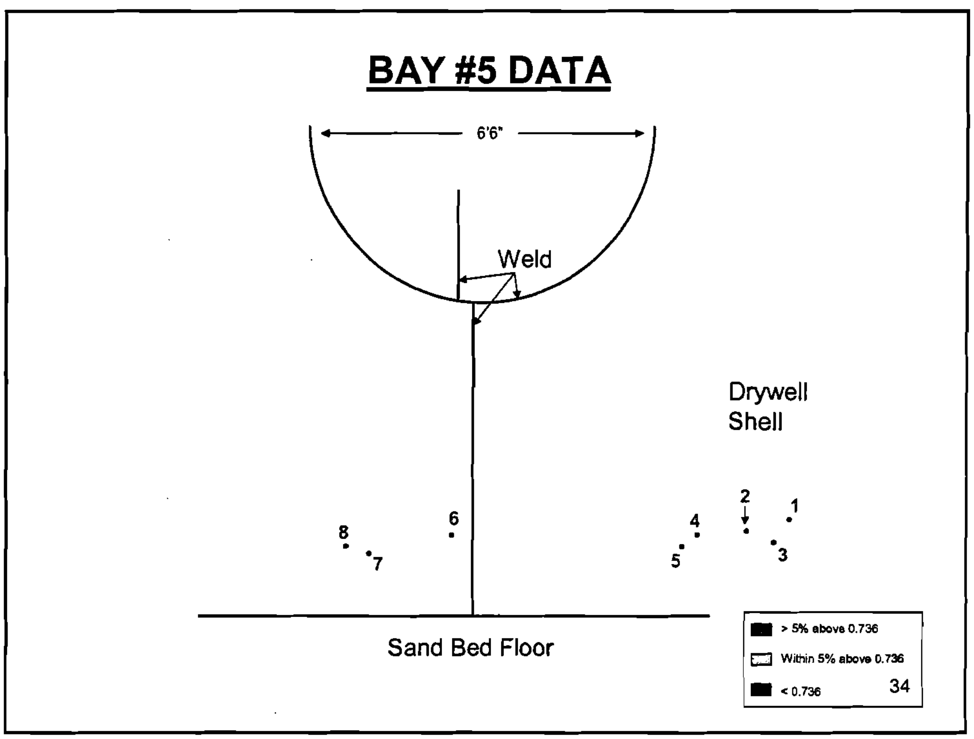
29

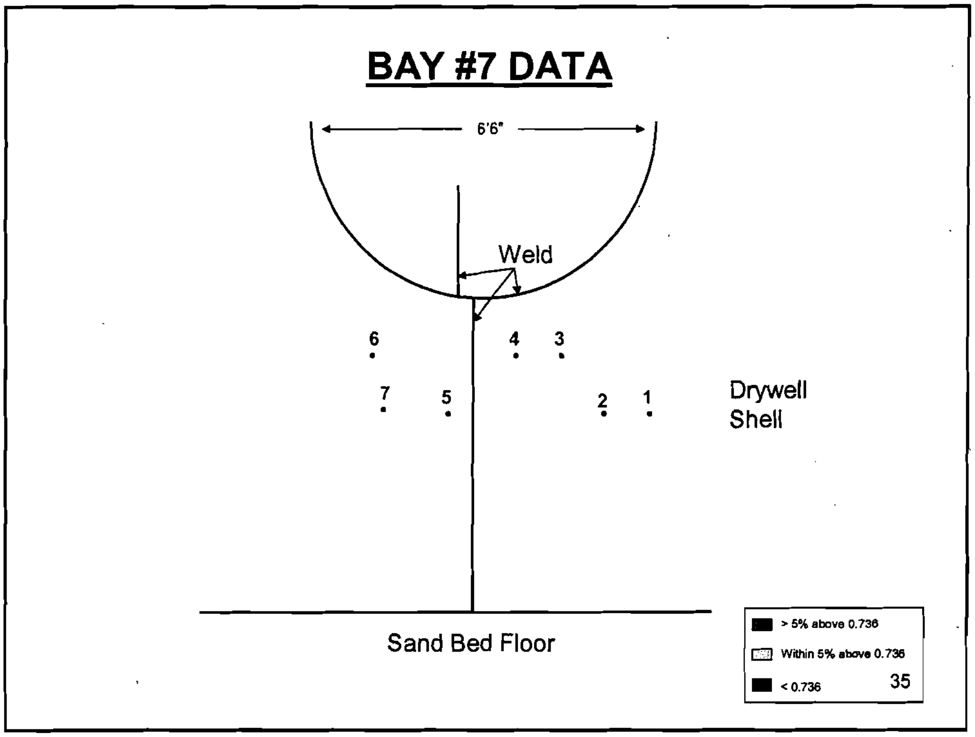


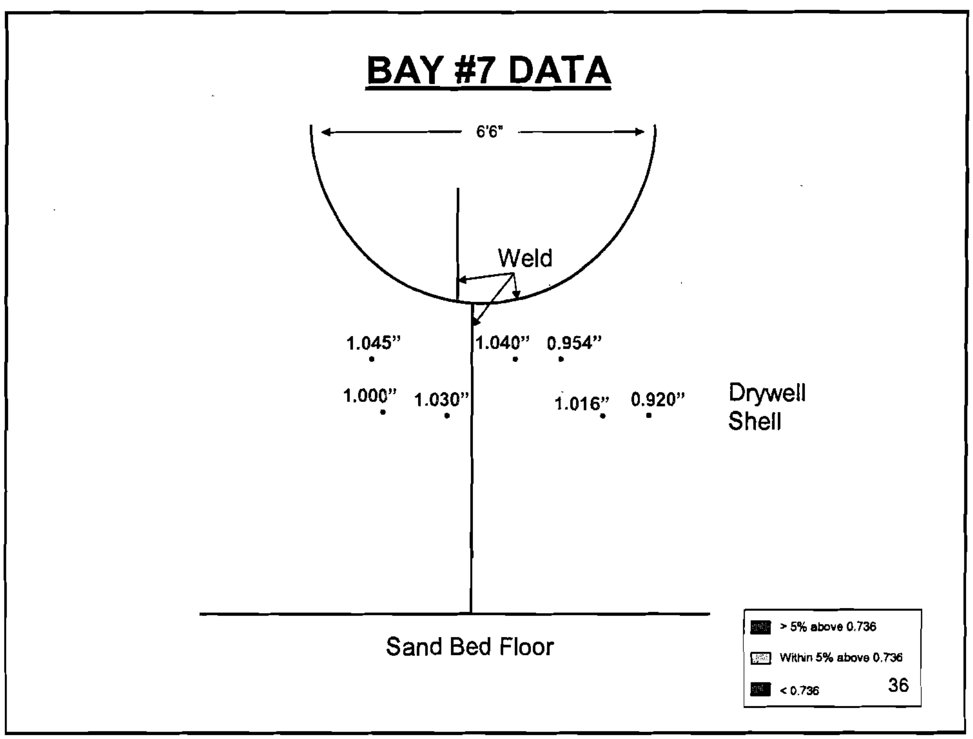

1992 External Spot Measurements Bay #1
6'6"
Weld
14
15
Bathtub Region
20
10
1
3
5
13
12
2
11
21
22
9
19
18
7
8
16
23
17
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
31

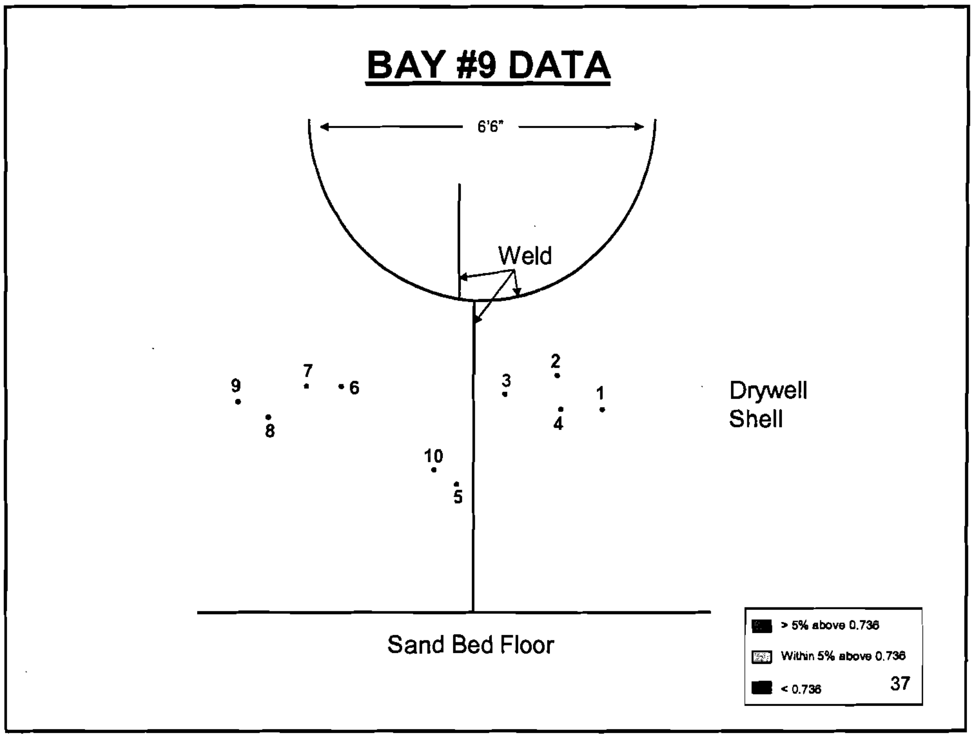

BAY #3 DATA
6'6"
Weld
1
2
3
6
5
4
7
8
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
32

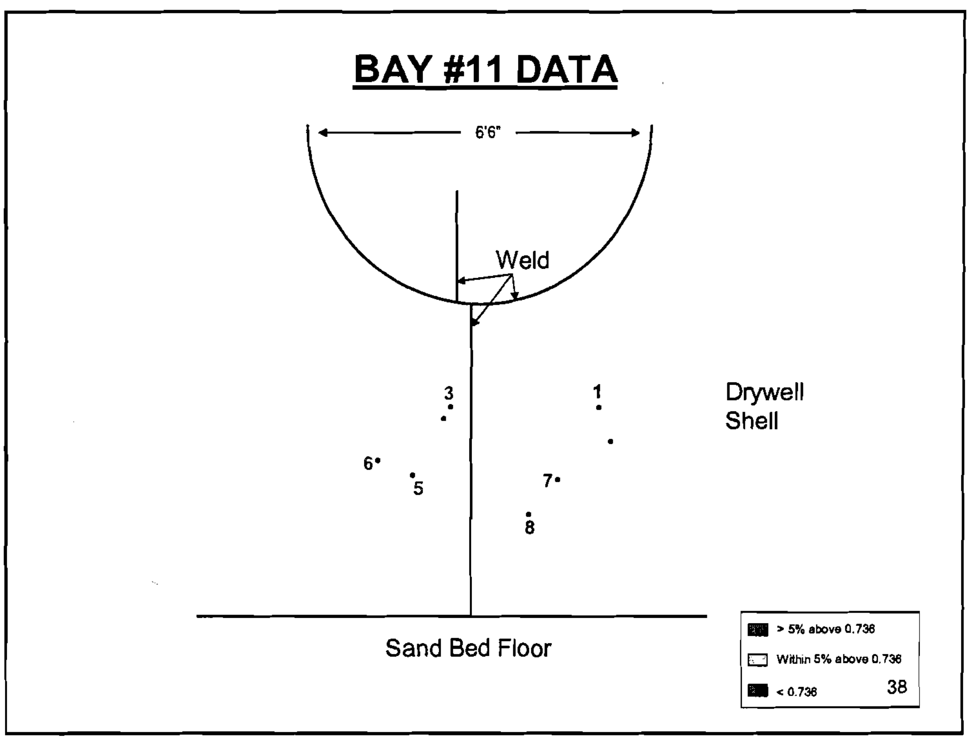

BAY #3 DATA
6'6"
Weld
0.795"
0.898"
0.857"
1.000"
0.968"
0.823"
0.826"
Drywell
Shell
0.780"
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
33

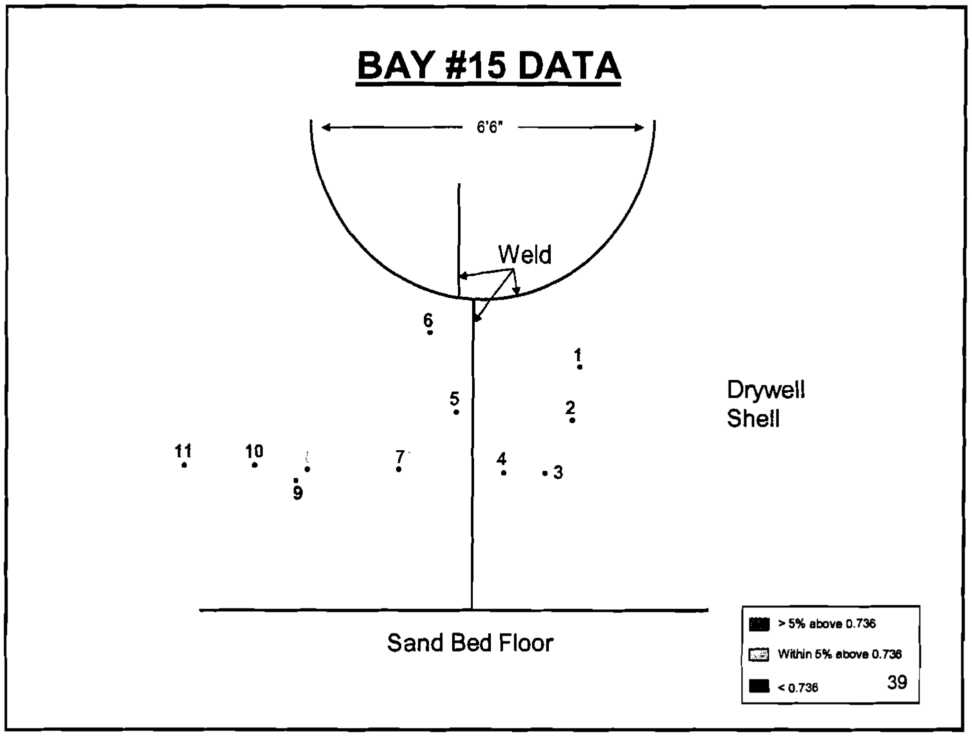

BAY #5 DATA
6'6"
Weld
Drywell
Shell
2
1
4
6
8
7
5
3
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
34

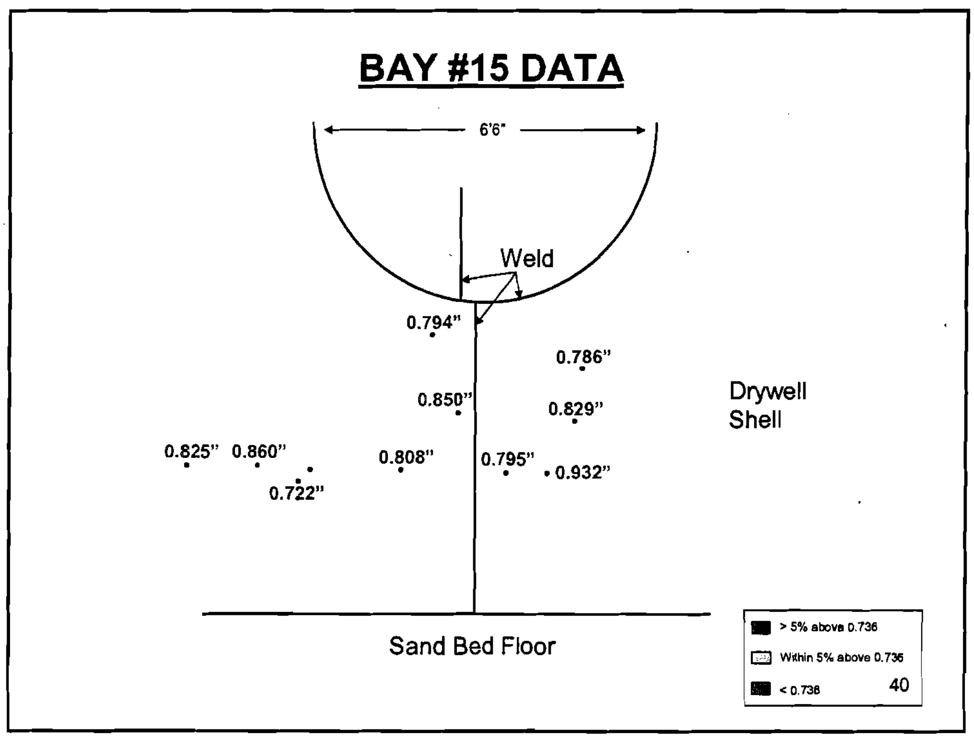

BAY #7 DATA
6'6"
Weld
6
4
3
7
5
2
1
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
35

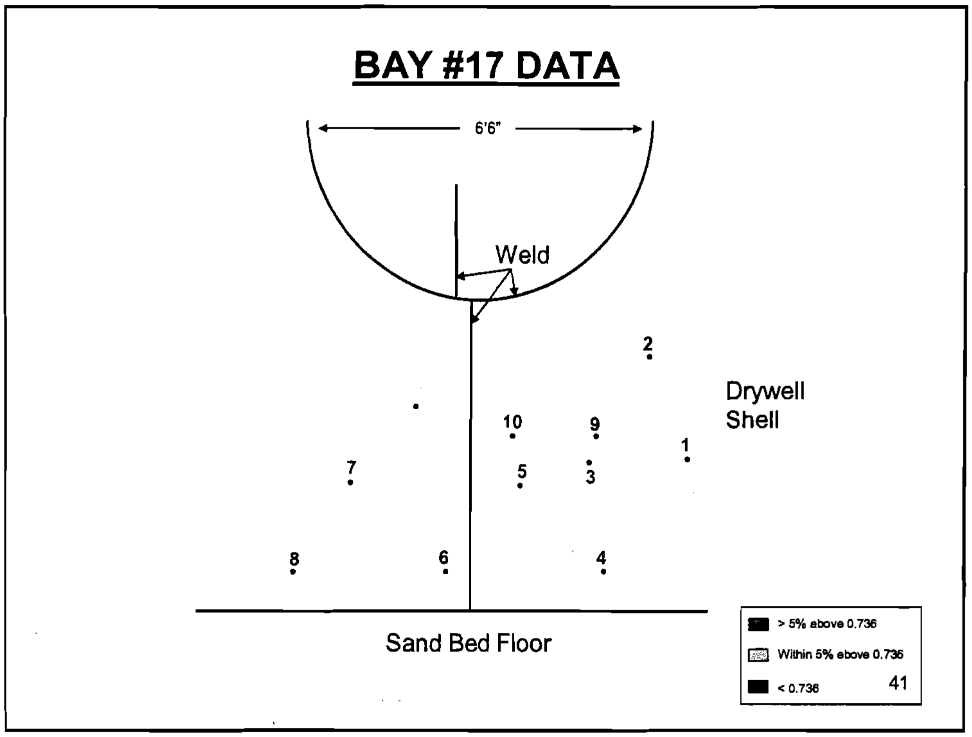

BAY #7 DATA
6'6"
Weld
1.045"
1.040"
0.954"
1.000"
1.030"
1.016"
0.920"
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
36

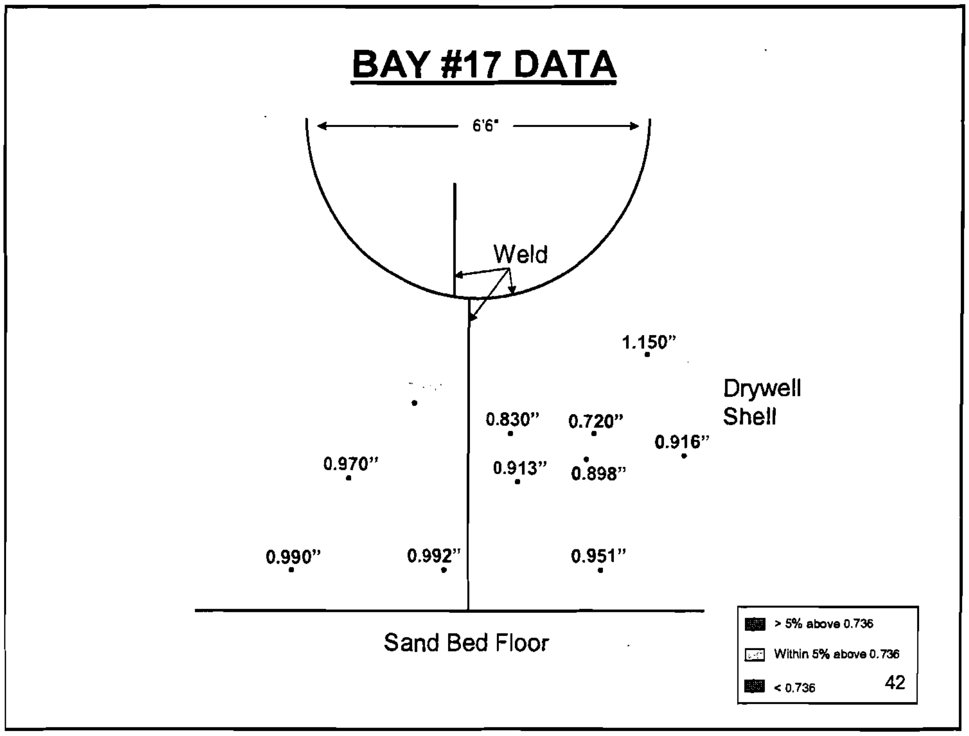

BAY #9 DATA
6'6"
Weld
7
9
6
8
10
5
3
2
1
4
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
37

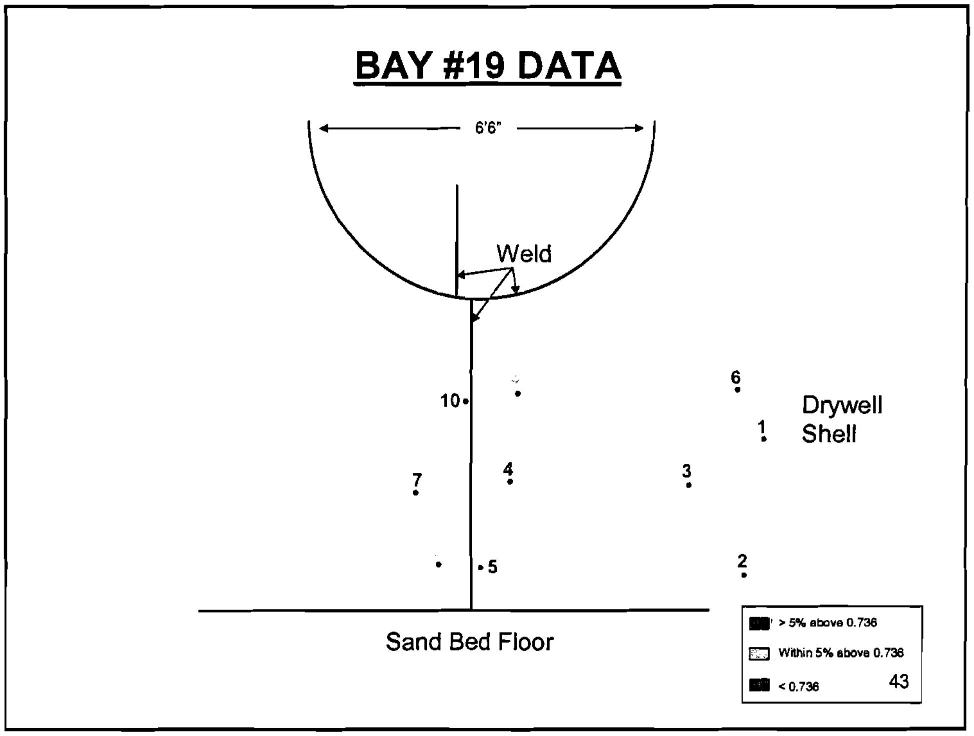

BAY #11 DATA
6'6"
Weld
3
1
6
5
7
8
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
38

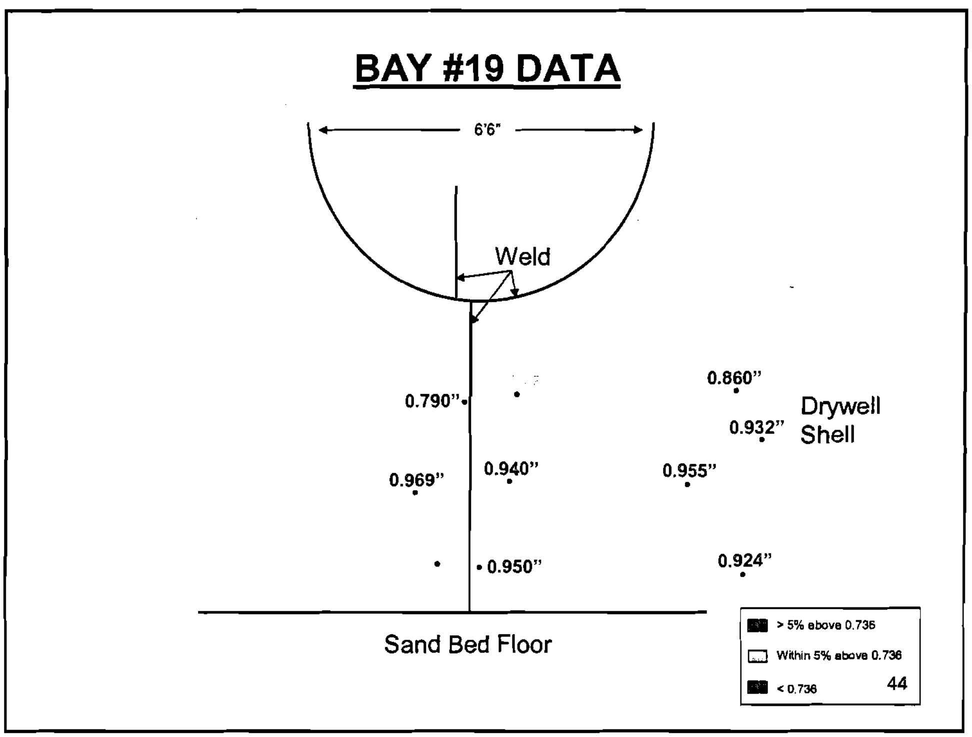

BAY #15 DATA
6'6"
Weld
6
1
5
2
11
10
7
4
3
9
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
39


BAY #15 DATA
6'6"
Weld
0.794"
0.786"
0.850"
0.829"
0.825"
0.860"
0.808"
0.795"
0.932"
0.722"
Drywell
Shell
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
40


BAY #17 DATA
6'6"
Weld
2
Drywell
Shell
10
9
1
7
5
3
8
6
4
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
41


BAY #17 DATA
6'6"
Weld
1.150"
Drywell
Shell
0.830"
0.720"
0.916"
0.970"
0.913"
0.898"
0.990"
0.992"
0.951"
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
42


BAY #19 DATA
6'6"
Weld
10
6
Drywell
Shell
1
7
4
3
5
2
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
43


BAY #19 DATA
6'6"
Weld
0.790"
0.860"
Drywell
Shell
0.932"
0.969"
0.940"
0.955"
0.950"
0.924"
Sand Bed Floor
> 5% above 0.736
Within 5% above 0.736
< 0.736
44

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Subcommittee

Oyster Creek Generating Station

Safety Evaluation Report

January 18, 2007

Donnie J. Ashley, Project Manager
Office of Nuclear Reactor Regulation

Introduction

- NRC Inspections during Fall 2006
- Status of Open Items / Licensee Commitments
- Confirmatory Analysis of Drywell - Sandia Model
- Socket Welds

License Renewal Inspections
October 2006

Rich Conte
Timothy O'Hara
Region I

OUTAGE INSPECTION IN OCTOBER 2006

SCOPE OF INSPECTION REVIEW

- Non-destructive examination results of the drywell shell and torus and related AmerGen evaluations.
- Visual inspection by NRC staff of epoxy coating on the outside of the drywell shell in 3 of 10 bays (adjacent bays could also be viewed) and NRC staff review of the results of licensee visual inspection in all 10 bays.
- AmerGen's efforts to identify and mitigate the source of water which accumulated in the trenches in the concrete floor inside the drywell.
  - tracer dye testing of the drywell leakage collection trough inside the reactor pedestal
  - inspection of the drywell sump
  - inspection and repair of the leakage collection trough
  - caulking of the joint between the concrete drywell floor and the steel drywell shell.
- Structural integrity of the concrete drywell floor and the condition of the embedded portion of the drywell shell.
- The potential impact from various repairs to the containment on the design and licensing bases of the drywell.

OUTAGE INSPECTION IN OCTOBER 2006

KEY NRC OBSERVATIONS/RESULTS

- All UT results are greater than the calculated minimum code required thickness for various plates that form the drywell shell.
- No adverse conditions of the epoxy coating on the outside of the drywell shell in the former sandbed region.
- Repairs in and around the trough within the reactor vessel pedestal area did not result in any adverse conditions.
- The water discovered in the drywell trenches had no adverse impact on the structural integrity of the concrete floor or the potential for corrosion of the embedded portion of the drywell shell.
  - AmerGen had taken actions to prevent further accumulation of water in this area.
- No adverse conditions with respect to the drywell or torus structural integrity that preclude restart.

OUTAGE INSPECTION IN OCTOBER 2006

INSPECTION SUMMARY

- No safety significant conditions with respect to the primary containment that would prohibit plant startup.
- Reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle.

Status of Open Items / Commitments

Donnie Ashley, NRR

5 open items:

- **<u>OI 4.7.2-1.1:</u>** Drywell Corrosion Sampling in the transition area: Question on the appropriate number of locations on the drywell for periodic ultrasonic testing

- **<u>OI 4.7.2-1.2:</u>** Drywell Corrosion Inaccessible areas embedded concrete: Question on the possibility of corrosion of drywell liner plates embedded in concrete between the containment floor and foundation

- **<u>OI 4.7.2-1.3:</u>** Buckling Analysis: Question on the appropriateness of certain technical assumptions in AmerGen's analysis of the potential for "buckling" of the drywell shell

- **<u>OI 4.7.2-1.4:</u>** Drywell Shell Thickness and the Minimum Available Thickness Margin: Question on the use of an ASME Code provision to simulate the behavior in thinned areas

- **<u>OI 4.7.2-3:</u>** Questions on the implementation of the Protective Coating Monitoring and Maintenance Program and the extent of inspections of epoxy-coated drywell surfaces

New Drywell Commitments

- **Increase sample sizes to 4 in transition area.**

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

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

New Drywell Commitments (condt)

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

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

Structural Integrity Analysis of the Degraded Drywell Containment at Oyster Creek

Hansraj Ashar, NRR
Jason Petti, SNL

Presented to ACRS Subcommittee
January 18, 2007

Scope and Intent of SNL Analysis

- The intent of this study was to assess the ability of the degraded drywell shell to withstand the postulated loadings
- 360° model of drywell was used to study the spatial variation of the degradation
- Stress and stability analyses of the drywell for as-designed and degraded shell conditions for postulated loads

Degradation Modeling

- Wall thinning used to model degradation.
- Region by region averages used based on reported measurements.
- Localized thinning was modeled in Bay 1 and Bay 13

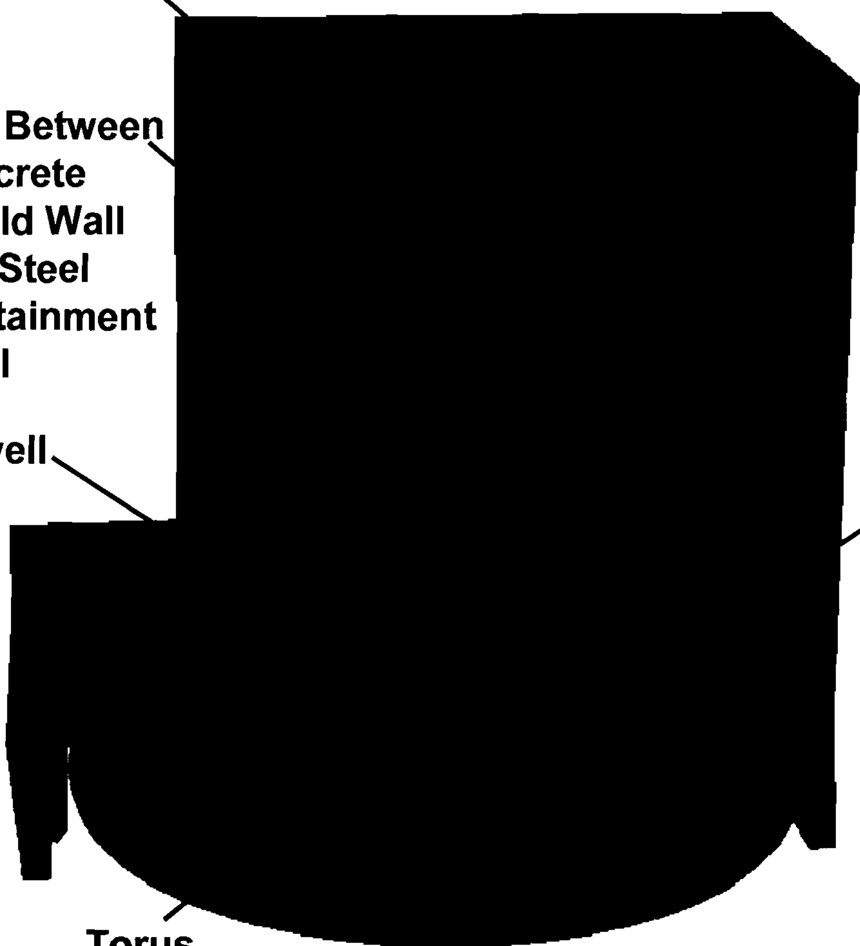
thickness

Oyster Creek
Reactor Building and Containment

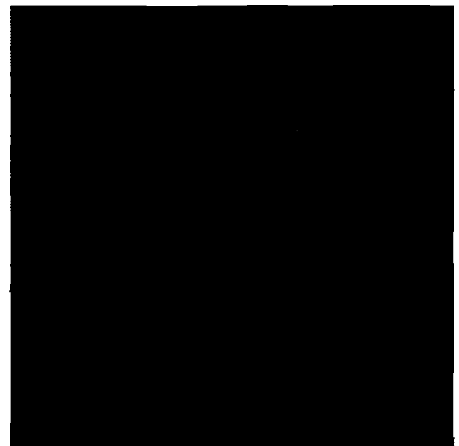
Reactor Building (one half removed to view containment)

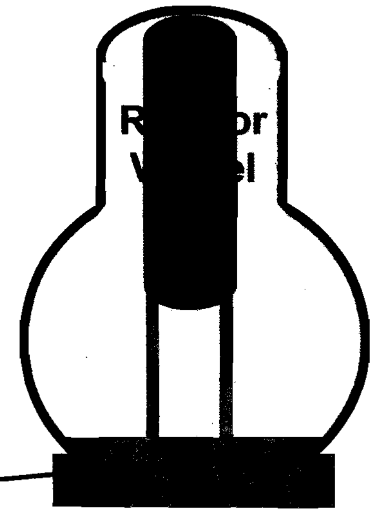
Gap Between Concrete Shield Wall and Steel Containment Shell

Drywell



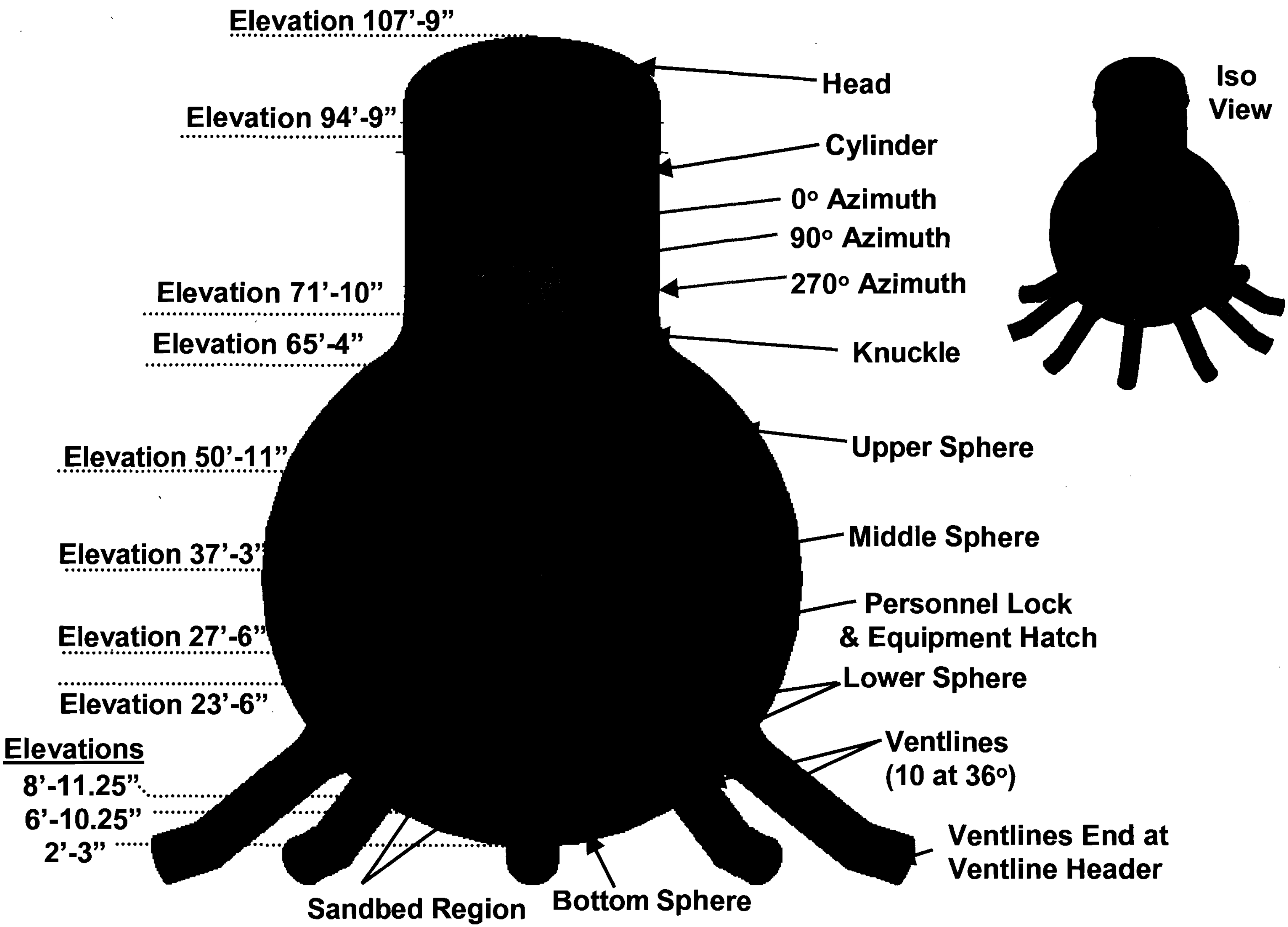
Torus



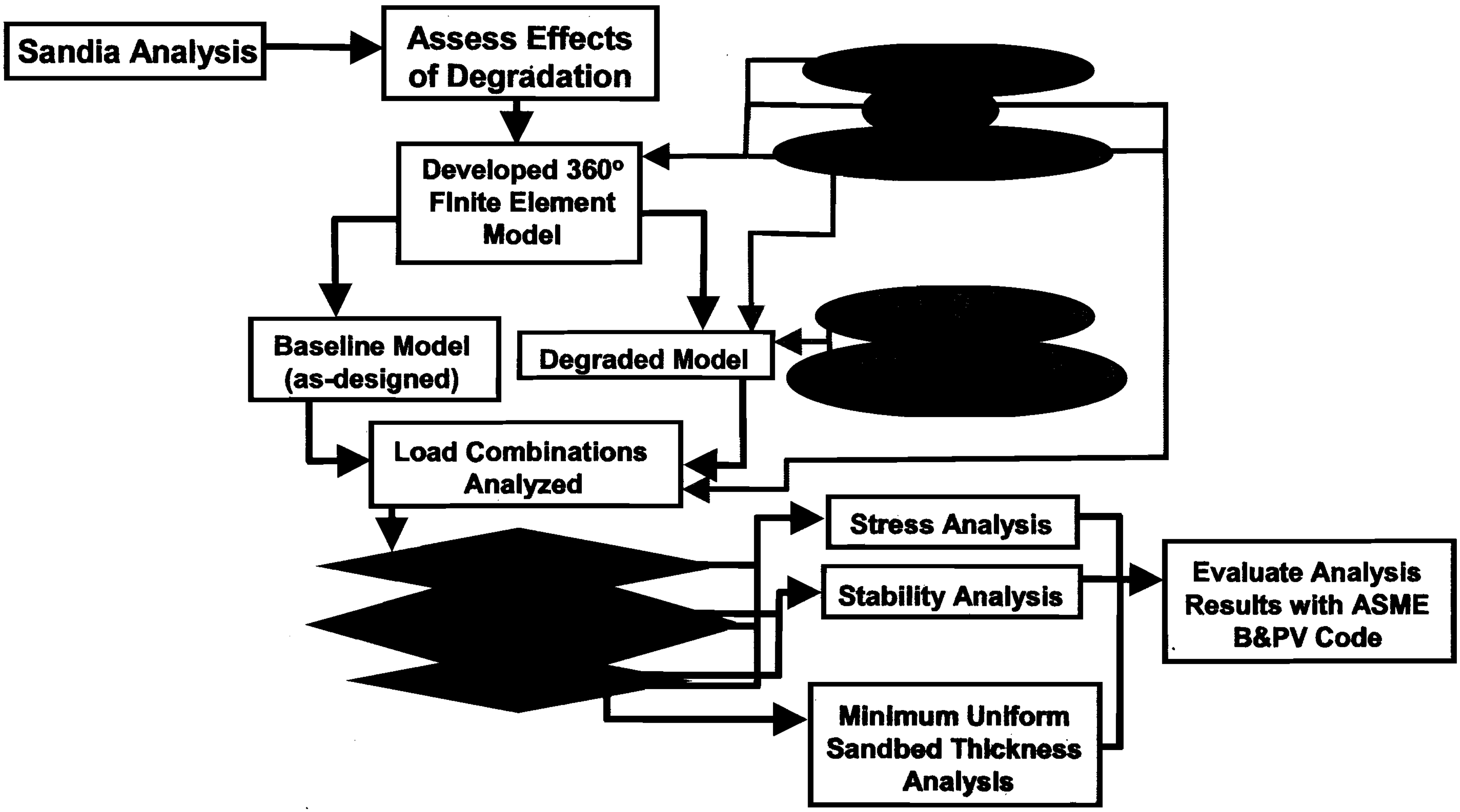


Sandbed Region

Drywell Model – Elevations and Regions



Model and Analysis Development



Analysis Results Summary

Load Combination		Baseline	Degraded
Refueling			
Dead, Seismic, Water	Stress	42%	51%
	Buckling (FS)	3.85 (2)	2.15 (2)
Accident			
Dead, Seismic, 44psi Int. Pressure, 292^{o}F	Stress	72%	93%
	Buckling (FS)	-	-
Post-Accident (flooded)			
Dead, Seismic, Hydrostatic	Stress	48.3%	63.3%
	Buckling (FS)	3.47 (1.67)	2.60 (1.67)

- Stress Ratio: Analysis Stress / Allowable Stress <100%
- Buckling Factors of Safety for Sandbed Region
- ASME B&PV Section III, Subsection NE

Stress plots

Conclusion of the Analysis

- Based on the SNL study, the NRC staff finds that the degradation in its current state meets the requirements of the ASME code

- The applicant has committed to future monitoring of the degradation and evaluation of the integrity of the Oyster Creek drywell shell as an ongoing process

Minimum thickness code

Socket Welds

Jim Davis, NRR

Inspection of Socket Welds in Class 1 Small-Bore Piping

Issue

- Aging management of socket welds in Class 1 and Class 2 small-bore piping (less than NPS 4 inches)

- Should socket welds be included in the "One-time Inspection of Small Bore Piping" AMP (XI.M35)

Socket Welds

- No additional examinations will be required for socket welds in excess of the current ASME code requirements

Conclusions

Donnie Ashley, NRR

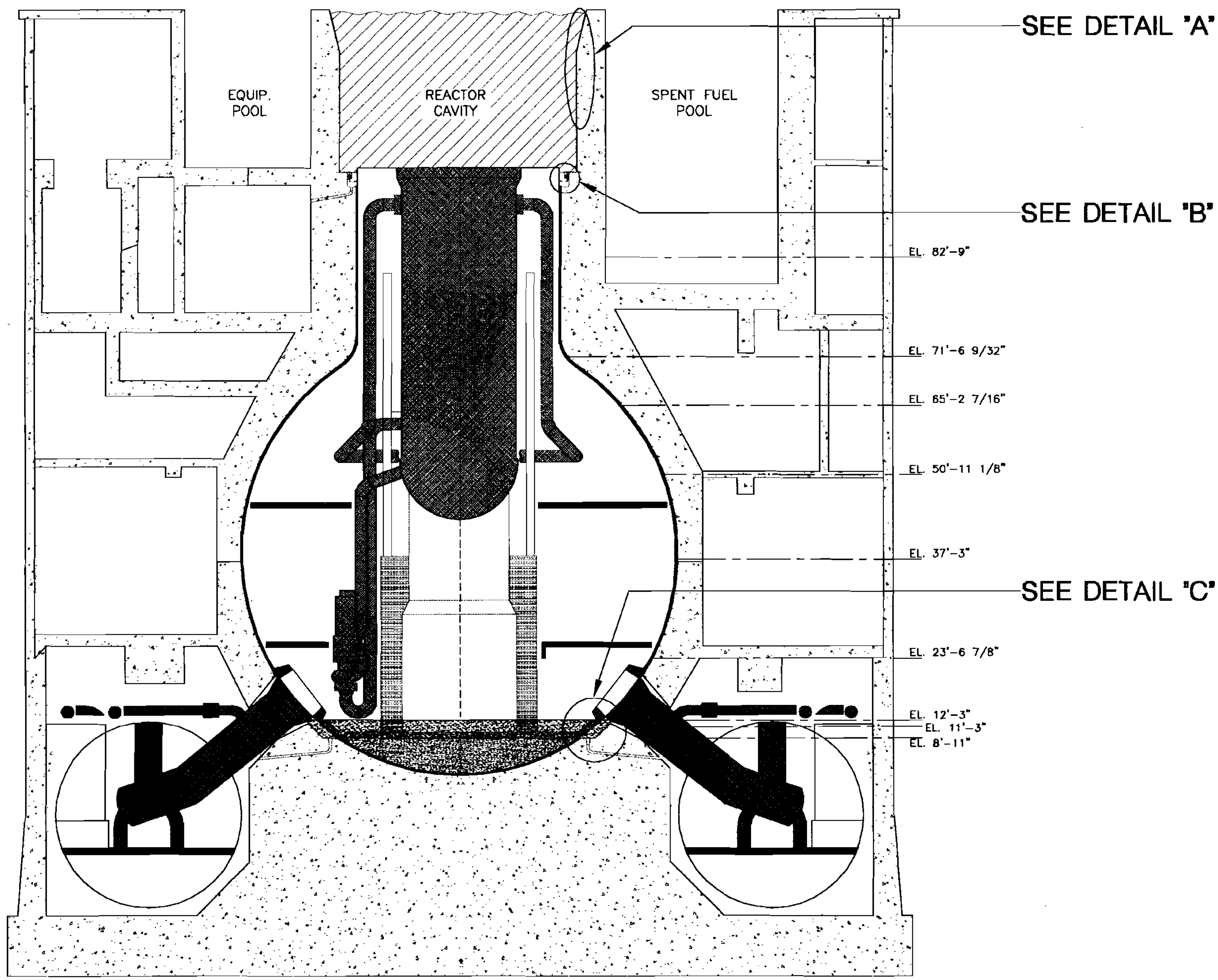
Conclusions

- The staff has concluded that with the resolution of the open items and additional commitments, there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the OCGS CLB in order to comply with 10 CFR 54.29(a) are in accordance with the Commission's regulations.

U.S.NRC

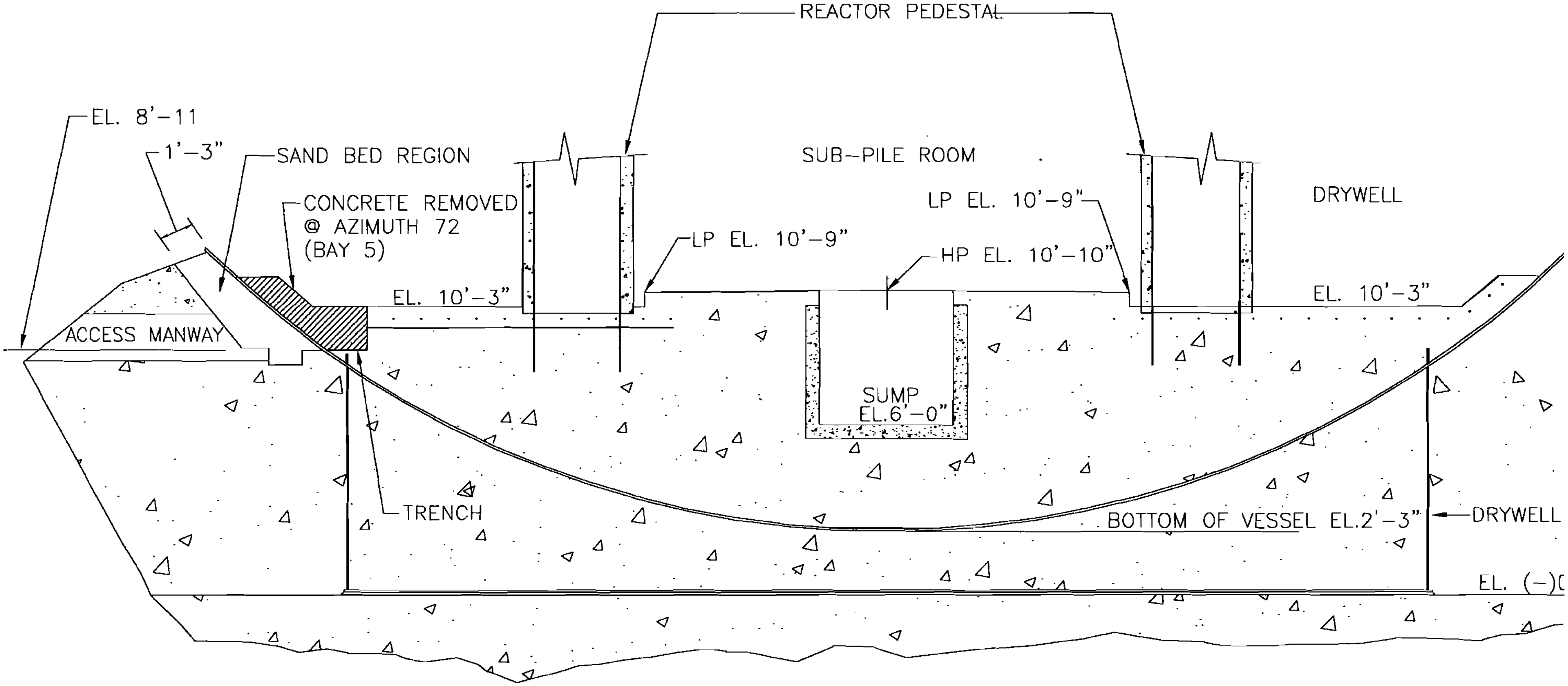
UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment



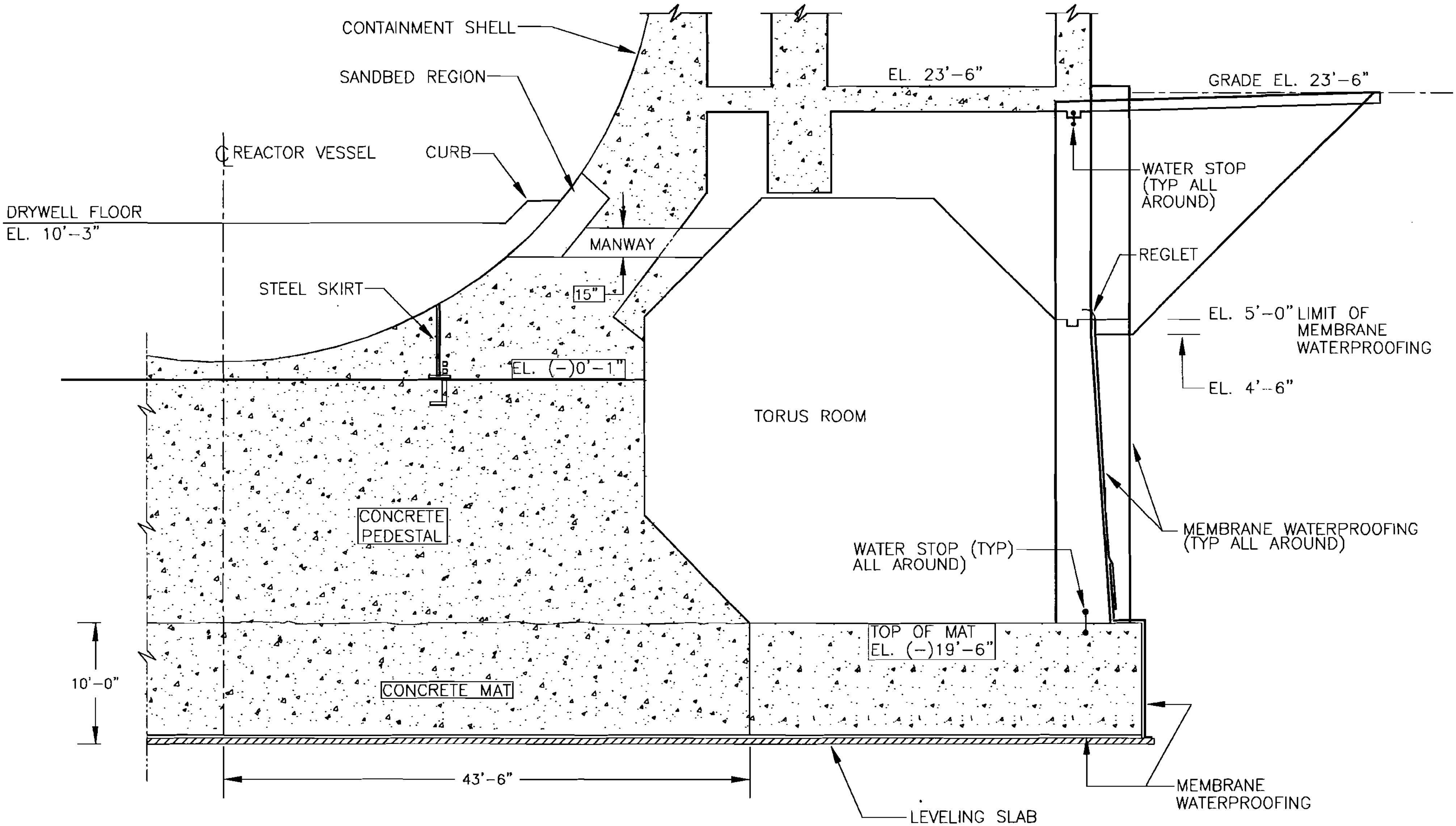
EQUIP. POOL
REACTOR CAVITY
SPENT FUEL POOL
SEE DETAIL "A"
SEE DETAIL "B"
SEE DETAIL "C"
EL. 82'-9"
EL. 71'-6 9/32"
EL. 65'-2 7/16"
EL. 50'-11 1/8"
EL. 37'-3"
EL. 23'-6 7/8"
EL. 12'-3"
EL. 11'-3"
EL. 8'-11"

LOWER DRYWELL-
SANDBED, TRENCH & SUMP

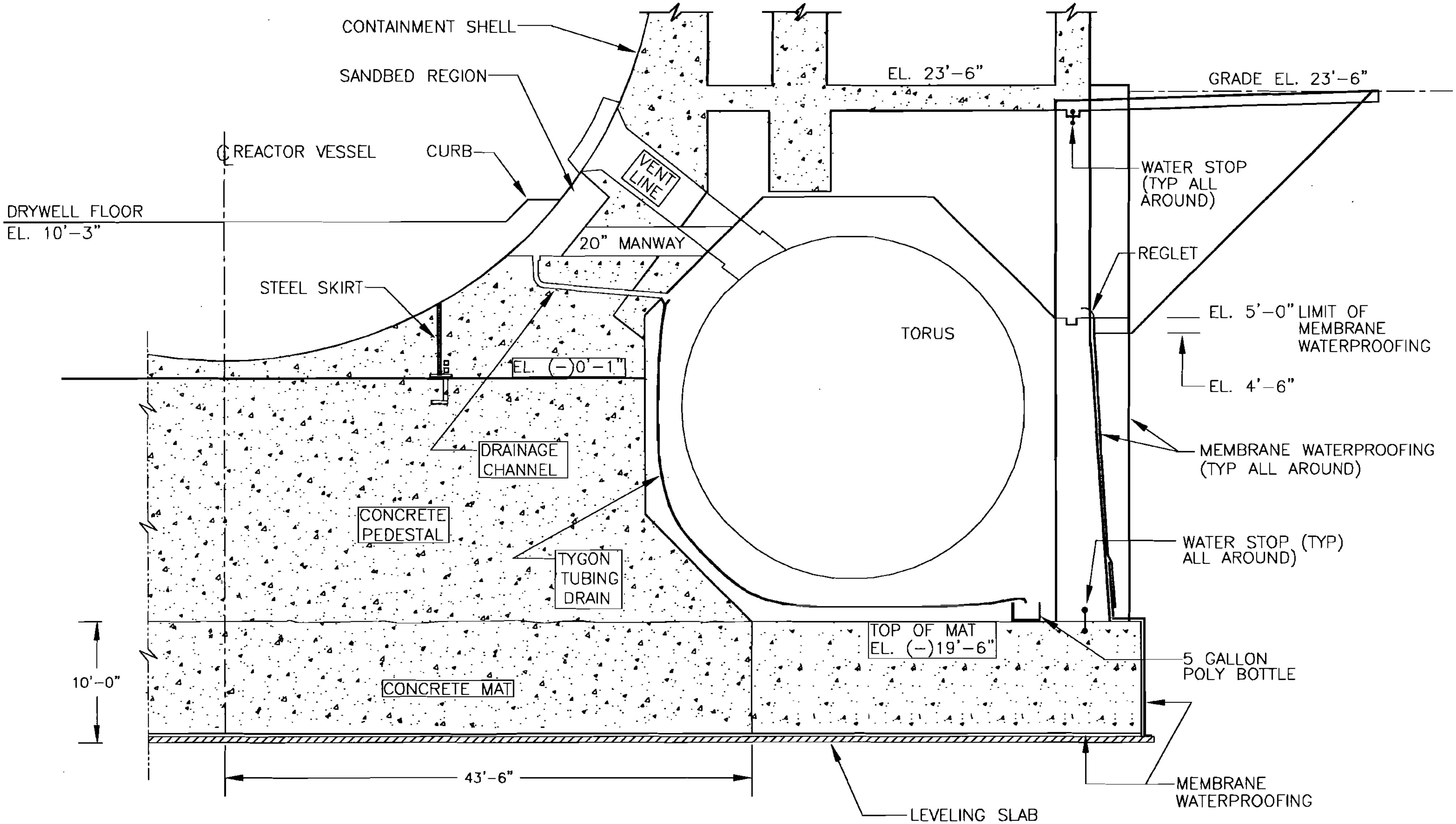


ELEVATION LOOKING WEST

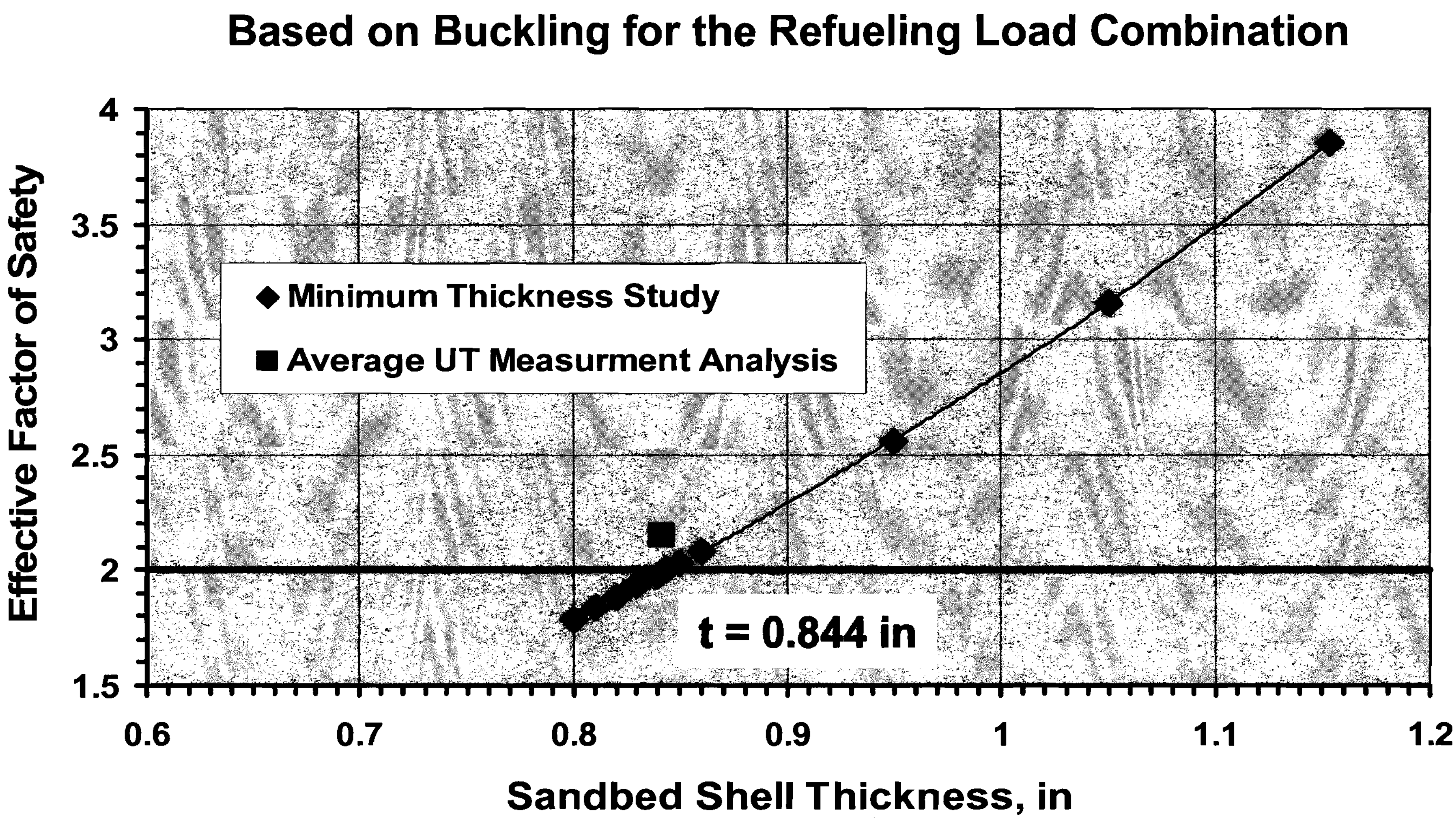
REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE



REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE



Minimum Uniform Sandbed Thickness



BACK

Thicknesses Used in Lower Sphere

Sphere Equator – Elevation 37'-3"

Bay Combinations

Ventline Locations

Elevation 23'-6"

[redacted]

Elevation 8'-11.25"

Sandbed Region

Local Bay 1 Region

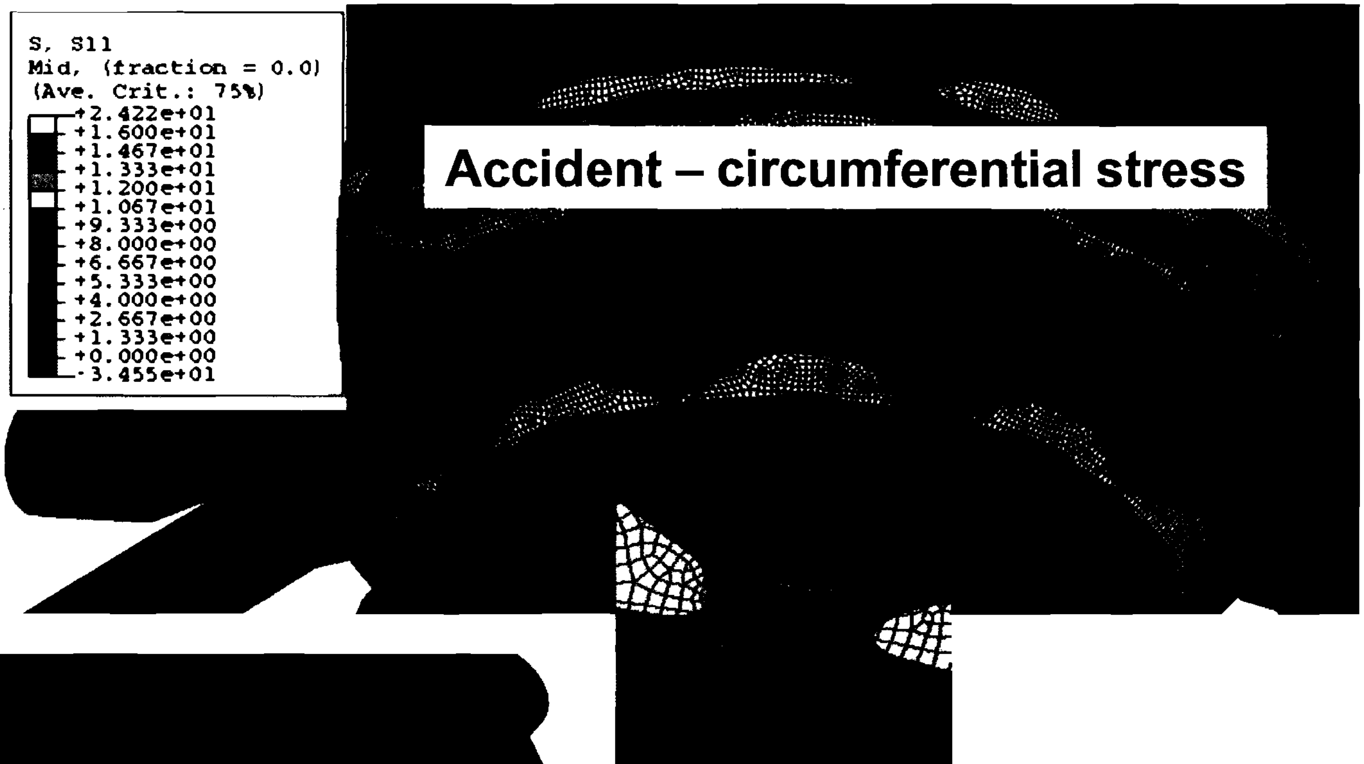
0.705

Local Bay 13 Region

0.618

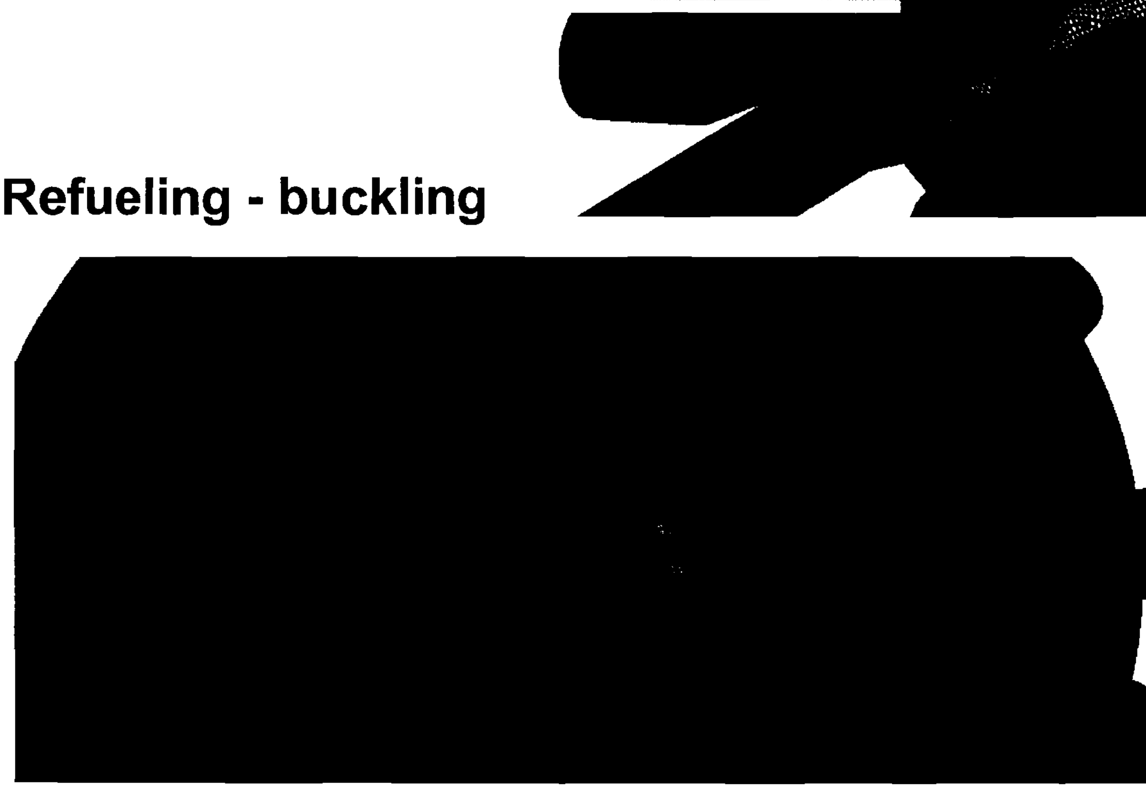
BACK

Analysis Results



Accident – circumferential stress

Refueling - buckling



BACK

ASME B&PV Code Case N-284

"-1500 CAPACITY REDUCTION FACTORS

…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 α_{ij} must be given in the Design Report."

BACK

December 11, 2006

MEMORANDUM TO: ACRS Plant License Renewal Subcommittee Members

FROM: Michael A. Junge, Senior Staff Engineer
Technical Support Branch, ACRS

SUBJECT: REVIEW MATERIALS FOR THE MEETING OF THE LICENSE RENEWAL SUBCOMMITTEE ON JANUARY 18, 2007 RELATED TO THE INTERIM REVIEW OF THE LICENSE RENEWAL OF THE OYSTER CREEK GENERATING STATION

The purpose of this memorandum is to forward background materials related to the License Renewal Subcommittee Meeting on January 18, 2007 with staff of the Office of Nuclear Reactor Regulation and AmerGen Power Company representatives to continue discussion on the License Renewal Application and Safety Analysis Report of Oyster Creek Generating Station.

To prepare for the meeting, the following documents are attached:

1) Oyster Creek License Renewal Project, Drywell Monitoring Program-Information for ACRS Subcommittee
2) Proposed Agenda
3) Status Report

For additional information, please contact me at (301) 415-6855 or MXJ2@NRC.GOV.

Attachments: As stated

cc: w/o Attachments: J. Larkins M. Snodderly S. Duraiswamy

Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee Meeting
Oyster Creek Generating Station
January 18, 2007
Rockville, MD

-PROPOSED SCHEDULE-

Cognizant Staff Engineer: Michael A. Junge mxj2@NRC.GOV (301) 415-6855

Topics	Presenters	Time
Opening Remarks	O. Maynard, ACRS	8:30am - 8:35 am
Staff Introduction	Louise Lund, NRR	8:35 am - 8:40 am
AmerGen - Oyster Creek Presentation A. Drywell Shell Corrosion Overview	 Fred Polaski,	8:40 pm - 9:30 am
B. Drywell Shell Thickness Analysis	Dr. Hardayal Mehta (GE), Ahmed Ouaou	9:30 am - 10:30 am
Break		10:30 am - 10:45 am
C. Drywell Sand Bed Region	John O'Rourke, Jon Cavallo, Pete Tamburro, Howie Ray	10:45 am - 12:00 pm
Lunch		12:00 pm - 1:00 pm
D. Embedded portions of the Drywell Shell	John O'Rourke, Barry Gordon, Howie Ray	1:00 pm - 1:45 pm
E. Upper Drywell Shell	John O'Rourke, Howie Ray	1:45 pm - 2:15 pm
Break		2:15 pm - 2:30 pm
NRC Staff Presentation A. Introduction/Overview	Donnie Ashley, NRR	2:30 pm - 2:35 pm
B. NRC inspection during 2006 outage	Richard Conte, Region I Tim O'Hara, Region I Michael Modes, Region I	2:35 pm - 2:50 pm
C. Status of Open Items / Licensee Commitments	Donnie Ashley, NRR Hans Ashar, NRR	2:50 pm - 3:00 pm
D. Confirmatory Analysis of Drywell - Sandia Model	Hans Ashar, NRR Jason Petti, SNL	3:00 pm - 3:45 pm

E. Socket Welds	Jim Davis, NRR	3:45 pm - 4:00 pm
Public Comment	Paul Gunter (NIRS), Richard Webster (NIRS)	4:00 pm - 5:00 pm
Subcommittee Discussion	O. Maynard, ACRS	5:00 pm-5:30 pm

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
SUBCOMMITTEE ON PLANT LICENSE RENEWAL
OYSTER CREEK GENERATING STATION
JANUARY 18, 2007
ROCKVILLE, MARYLAND

- STATUS REPORT -

PURPOSE

The purpose of this meeting is to review the License Renewal Application (LRA) for Oyster Creek Generating Station (OCGS), and the associated Draft Safety Evaluation Report (SER) December 2006 update, dated December 29, 2006, with focus on questions that were raised during the October 3, 2006 License Renewal Subcommittee meeting. This updated SER closed the open items contained in the previous Draft SER with open items dated August 2006. The Subcommittee will hear presentations by and hold discussions with representatives of the staff and AmerGen Energy Company.

BACKGROUND

The Oyster Creek Generating Station (OCGS) is a single unit facility. It is located in Lacey Township, Ocean County, New Jersey, approximately two miles south of the community of Forked River, about two miles inland from the shore of Barnegat Bay and seven miles west-north-west of Barnegat Light. The site, about 800 acres, is approximately nine miles south of Toms River, New Jersey, about fifty miles east of Philadelphia, Pennsylvania, and sixty miles south of Newark, New Jersey. The reactor is a single cycle, forced circulation boiling water reactor (BWR-2) with a Mark 1 type Containment. The reactor produces steam for direct use in the steam turbine. The primary containment is of the Mark 1 design that consists of a drywell, a suppression chamber in the shape of a torus and a connecting vent system between the drywell and the suppression chamber.

Initial criticality was achieved on May 3, 1969 and Oyster Creek Generating Station was placed in commercial operation on December 23, 1969 under a Provisional Operating License. On July 2, 1991, the NRC issued a Full Term Operating License (Facility Operating License No. DPR-16) which superseded the Provisional Operating License in its entirety. On August 8, 2000, Oyster Creek Generating Station was acquired by and the license transferred to AmerGen. The License permits steady-state reactor core power levels not in excess of 1930 megawatts (thermal) and is in effect until midnight on April 9, 2009.

DISCUSSION

By letter dated July 22, 2005(ADAMS Accession No. ML052080048), AmerGen submitted the License Renewal Application (LRA) for OCGS in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54).

AmerGen is requesting renewal of the operating licenses for OCGS, (Facility Operating License DPR-16) for a period of 20 years beyond the current expiration date of April 9, 2009. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) reviewed the license renewal application (LRA) for Oyster Creek Generating Station in accordance with the NRC regulations and NUREG-1800, Revision 1, "Standard Review Plan for Review of License

Renewal Applications for Nuclear Power Plants," dated September 2005. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

The licensee stated that it had not identified any Technical Specification (TS) changes necessary to support issuance of the renewed operating license.

The staff used the following Interim Staff Guidance (ISG) in the Oyster Creek LRA review: Station Blackout (SBO) Scoping, Concrete Aging Management Program (AMP), Fire Protection (FP) System Piping, and Identification & Treatment of Electrical Fuse Holders.

The December 2006 update to the Draft SER presents the status of the staff's review of information submitted through December 15, 2006. It closes the 5 open items contained in the previous Draft SER, and has no confirmatory items, 3 proposed license conditions, and 65 commitments.

<u>OPEN ITEMS</u>

The following 5 open items have been closed.

1. In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: For the drywell corrosion (lower portion of the spherical area above the sand-pocket area) during the late 1980s and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done to identify the areas of corrosion has been adequate. The staff finds that the applicant's actions to include in the program UT measurement of shell areas that may experience increased rates of corrosion resolves the staff concern. *The basis for this finding is that the UT measurements should provide an adequate data base to confirm whether the random sampling program for UT measurements is reasonably representative.* The staff, however, noted an inconsistency in the license renewal commitment list (pages 45 and 46, items 10 and 11) where it states that the UT measurements will be at one location. In a letter dated December 15, 2006, the applicant noted the editorial error in its letter dated December 3, 2006. The applicant corrected the error by changing item 10 and 11 from UT measurements at one location to UT measurements at four locations. Open Item OI 4.7.2-1.1 is closed.

2. In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: For the drywell corrosion (sand pocket region of the drywell shell) during the late 1980s and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done to identify the areas of corrosion has been adequate. Based on review of the applicant's evaluation of the condition of the inaccessible portion of drywell shell embedded in concrete, the applicant's actions to date, and the enhanced inspection program including a detailed UT measurement plan to which the applicant committed, the staff concludes with reasonable assurance that the environment in the region is sufficiently non-aggressive for no significant progressive corrosion. Therefore, the staff concern is resolved and Open Item 4.7.2-1.2 is closed.

3. In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: A summary of the factors considered in establishing the minimum required drywell thickness. On further evaluation of the applicant's information, the staff concluded that the stability evaluation was consistent with the guidelines of ASME Code Case N-284-1. The staff's concern about use of the same section strength across the corroded section of the shell is addressed by Code Case N-284-1, which uses conservative assumptions to determine shell capacity reduction factors (i.e., assumption of imperfection limit indicated by parameter "e/t" to be 1.0 in the code case) expected to compensate reasonably for such use of the same section strength. In addition, the applicant conservatively assumed the local corroded thickness for the entire drywell shell region and demonstrated that the code-allowable stresses were satisfied consistently with the guidelines of the code case. Thus, this analysis adds a margin of safety for the drywell stability evaluation. On this basis, the staff believes that the stability evaluation method is adequate and acceptable, and the staff's concern is resolved. Open Item 4.7.2-1.3 is closed.

4. In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: A summary of the factors considered in establishing the minimum required drywell thickness. After further evaluation of the applicant's justification, the staff accepts the use of the NE-3213.10 provisions of Subsection NE of ASME Code Section III. The staff acceptance is based on the the applicant's conservative approaches to its determination of the allowable shell capacity. Specifically, the applicant demonstrated acceptable shell capacity based on a conservative LOCA peak internal pressure (i.e., peak internal pressure of 62 psi in the evaluation versus the 44 psi peak internal pressure in an Oyster Creek specific calculation approved by the NRC in 1993), use of a local corroded thickness for the entire region of the drywell, and compliance with local primary stress code limits in the corroded condition. In addition, the applicant expects its enhanced actions to prevent significant additional corrosion in the sand bed region. With this information, the staff's concern is resolved and Open Item 4.7.2-1.4 is closed.

5. In RAI 4.7.2-3 dated March 10, 2006, the staff noted that leakage from the refueling seal has been identified as one of the reasons for accumulation of water and contamination of the sand-pocket area. The refueling water passes through the gap between the shield concrete and the drywell shell in the long length of inaccessible areas. As there is a potential for corrosion, ASME Code Subsection IWE would require augmented inspection of this area. The staff requested that the applicant provide a summary of inspections (visual and NDE) and mitigating actions to prevent water leaks from the refueling seal components. In a letter dated June 23, 2006, the applicant committed to monitoring of the coating on the drywell shell exterior in the sand bed region as part of its ASME Section XI, Subsection IWE 1-18 Program and of its Protective Coating Monitoring and Maintenance Program. The applicant committed to additional visual inspections of the epoxy coating in all 10 drywell bays at least once prior to the period of extended operation. In a letter dated December 3, 2006, the applicant stated that 100 percent of the epoxy coating had been inspected during the October 2006 outage with no evidence of flaking, blistering, peeling, discoloration, or other signs of coating distress. The staff finds that these commitments with the IWE program and the absence of evidence of coating deterioration in the October 2006 inspection resolve the concern over the extent of coatings inspections; therefore, the staff's concern is resolved and Open Item 4.7.2-3 is closed.

PROPOSED LICENSE CONDITIONS

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

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

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

COMMITMENTS

Commitments made by the licensee are listed in detail in Appendix A to the SER. The licensee made 65 commitments related to the AMPs to manage aging effects of structures and components prior to the periods of extended operation. The following are a summary:

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD. Existing program is credited. For the isolation condensers this program also includes enhancement activities identified in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," lines IV.C1-5 and IV.C1-6. These enhancement activities consist of: (1) Temperature and radioactivity monitoring of the shell-side (cooling) water, which will be implemented prior to the period of extended operation. (2) Eddy current testing of the tubes, with inspection (VT or UT) of the tubesheet and channel head, which will be performed during the first ten years of the extended period of operation.
2. Water Chemistry existing program is credited.
3. Reactor Head Closure Studs existing program is credited.
4. BWR Vessel ID Attachment Welds existing program is credited.
5. BWR Feedwater Nozzle. Existing program is credited. The Oyster Creek Feedwater Nozzle Program will be enhanced
6. BWR Control Rod Drive Return Line Nozzle Existing program is credited.
7. BWR Stress Corrosion Cracking Existing program is credited. The program will be enhanced.
8. BWR Penetrations existing program is credited.
9. BWR Vessel Internals Existing program is credited. The program will be enhanced.
10. Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS). Program is new.
11. Flow-Accelerated existing program is credited.
12. Bolting Integrity existing program is credited. Program site implementing documents will be enhanced.
13. Open-Cycle Cooling Water System Existing program is credited. The program will be enhanced.
14. Closed-Cycle Cooling Water System Existing program is credited.
15. Boraflex Monitoring Existing program is credited.

16. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems existing program is credited. The scope of the program will be increased and enhanced.
17. Compressed Air Monitoring existing program is credited.
18. BWR Reactor Water Cleanup System Existing program is credited. Based on Generic Letter 89-10 containment isolation valve upgrades/enhancements, an effective Hydrogen Water Chemistry program, and the complete lack of cracking found during any of the RWCU piping weld inspections performed under Generic Letter 88-01, all inspection requirements for the portion of the RWCU System outboard of the second containment isolation valves have been eliminated.
19. Fire Protection existing program is credited. The program will be enhanced.
20. Fire Water System existing program is credited. The program will be enhanced.
21. Aboveground Outdoor Tanks is a new program..
22. Fuel Oil Chemistry will be enhanced.
23. Reactor Vessel Surveillance will be enhanced.
24. One-Time Inspection is a new program.
25. Selective Leaching of Materials is a new program.
26. Buried Piping Inspection existing program is credited. The program will be enhanced.
27. ASME Section XI, Subsection IWE existing program is credited. The program will be enhanced.
28. ASME Section XI, Subsection IWF existing program is credited. The scope of the program will be enhanced.
29. 10 CFR Part 50, Appendix J existing program is credited.
30. Masonry Wall Program existing program is credited.
31. Structures Monitoring Program existing program is credited.
32. RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants existing program is credited.
33. Protective Coating Monitoring and Maintenance Program existing program is credited.
34. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program.
35. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits existing program is credited. The program will be enhanced.
36. Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program.
37. Periodic Testing of Containment Spray Nozzles existing program is credited.
38. Lubricating Oil Monitoring Activities existing plant specific program is credited.
39. Generator Stator Water Chemistry Activities existing program is credited.
40. Periodic Inspection of Ventilation Systems existing plant specific program is credited.
41. Periodic Inspection Program is a new program.
42. Wooden Utility Pole Program is a new program.
43. Periodic Monitoring of Combustion Turbine Power Plant - Electrical A new plant specific program is credited.
44. Metal Fatigue of Reactor Coolant Pressure Boundary existing program is credited.
45. Environmental Qualification (EQ) Program existing program is credited.
46. New P-T curves Revised pressure-temperature (P-T) limits for a 60-year licensed operating life have been prepared and will be submitted to the NRC for approval.
47. Circumferential Weld Exam Relief Apply for extension Reactor Vessel Circumferential Weld Examination Relief for 60-year operation.

48. Axial weld Exam Relief Apply for extension Reactor Vessel Axial Weld Examination Relief for 60-year operation.
49. Measure Drywell wall thickness Drywell wall thickness will be monitored to ensure minimum wall thickness is maintained. The ASME Section XI, Subsection IWE Program, will manage the aging effects.
50. Fluence Methodology The NRC has issued a SER for RAMA approving RAMA for reactor vessel fluence calculations. Oyster Creek will comply with the applicable requirements of the SER.
51. Bolting Integrity - FRCT. The Bolting Integrity - FRCT Program is a new program.
52. Closed-Cycle Cooling Water System - FRCT. The Closed-Cycle Cooling Water System – FRCT Program is a new program.
53. Aboveground Steel Tanks - FRCT. The Above ground Steel Tanks - FRCT Program is a new program.
54. Fuel Oil Chemistry – FRCT. The Fuel Oil Chemistry - FRCT Program is a new program.
55. One-Time Inspection - FRCT. The One-Time Inspection – FRCT program will provide measures to verify that an aging management program is not needed, confirms the effectiveness of existing activities, or determines that degradation is occurring which will require evaluation and corrective action. The program will be implemented prior to the period of extended operation.
56. Selective Leaching of Materials -FRCT. The Selective Leaching of Materials - FRCT Program is a new program.
57. Buried Piping Inspection – FRCT. The Buried Piping Inspection - FRCT Program is a new program.
58. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components- FRCT. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program is a new program.
59. Lubricating Oil Analysis Program – FRCT. The Lubricating Oil Analysis Program – FRCT is a new program.
60. Periodic Inspection Program - FRCT. The Periodic Inspection Program - FRCT is a new program.
61. Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply. The Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply Program is a new program.
62. AmerGen will commit to perform monitoring of any leakage from the spent fuel pool liner via the pool leak chase piping.
63. AmerGen will replace the previously un-replaced, buried safety-related ESW piping prior to the period of extended operation.
64. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program .
65. Corrective Action, Confirmation and Administrative Controls for Forked River Combustion Turbine activities. Prior to the period of extended operation, AmerGen will ensure that procedures are established to implement the program elements of Corrective Action, Confirmation, and Administrative Controls, as described in Sections A.0.5 and B.0.3 of Enclosure 1 of AmerGen letter 2130-06-20334, for the Forked River Combustion Turbine aging management activities.

SCOPING & SCREENING AND AUDIT OF AMPs & AMRs

The staff performed a scoping and screening methodology inspection, AMP inspection, and an audit of the AMPs and aging management reviews (AMRs).

The staff's scoping and screening methodology inspection has been completed, with an exit meeting scheduled September 13, 2006. The report will be issued shortly after the exit meeting. The audit of the AMPs and AMRs is documented in a report by Brookhaven National Laboratory dated May 9, 2006. The audit examined 29 AMPs and the associated AMRs in the LRA. The project team reviewed 28 AMPs and associated AMRs that the licensee claimed were consistent with the GALL Report. The project team also reviewed one plant-specific AMP. The audit verified that the AMPs were consistent with GALL. The audit also concluded that the AMRs were consistent with the GALL Report.

TLAAs

Based on OCGS's current licensing basis, UFSAR, and design-basis documents, the following categories of Time Limited Aging Analyses (TLAAs) were considered:

- neutron embrittlement of reactor vessel and internals
- metal fatigue of the reactor vessel, internals, and reactor coolant pressure boundary (RCPB) piping and components
- environmental qualification (EQ) of electrical equipment
- loss of prestress in concrete containment tendon
- fatigue analysis of primary containment, attached piping, and components
- reactor building crane, turbine building crane, heater bay crane load cycles
- drywell corrosion
- equipment pool and reactor cavity walls rebar corrosion
- reactor vessel weld flaw evaluations
- control rod drive (CRD) stub tube flaw analysis

On the basis of its review, the staff concludes, subject to the resolution OIs 4.7.2-1.1, 4.7.2-1.2, 4.7.2-1.3, 4.7.2-1.4, and 4.7.2-3, that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concludes that the applicant has demonstrated that (1) the TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(I), (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) that the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and found that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, consistent with 10 CFR 54.21©)(2), the staff concludes that no plant-specific, TLAA-based exemptions are in effect.

PREVIOUS SUBCOMMITTEE MEETING

Following the License Renewal Subcommittee Meeting on October 3, 2006, several questions were developed regarding Drywell corrosion. The Subcommittee requested that there be another Subcommittee meeting to obtain answers to these questions.

EXPECTED SUBCOMMITTEE ACTION

The Subcommittee Chairman will provide a report to the Full Committee during the February 2007 ACRS meeting.

June 25, 2007

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March 8, 2007

Dr. William J. Shack, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Dr. Shack:

During the 539th meeting of the Advisory Committee on Reactor Safeguards (ACRS or the Committee) held on February 1–3, 2007, the ACRS completed its review of the license renewal application (LRA) for the Oyster Creek Generating Station (OCGS) and the associated final safety evaluation report (SER) prepared by the U.S. Nuclear Regulatory Commission (NRC) staff. In its final report, the Committee recommends renewal of the OCGS operating license in conjunction with the recommendations discussed in your letter dated February 8, 2007. The staff appreciates the Committee's expeditious, objective, and in-depth review of the LRA and the staff's final SER. The staff agrees with the Committee's recommendations:

1. The staff will impose a license condition to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

2. The staff will ensure that the applicant fulfills its commitment to (a) perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner, and (b) perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued support of the license renewal process.

Sincerely,

/RA/

Luis A. Reyes
Executive Director
for Operations

cc: Chairman Klein
Commissioner McGaffigan
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

March 8, 2007

Dr. William J. Shack, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

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The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued support of the license renewal process.

Sincerely,

/RA/

Luis A. Reyes
Executive Director
for Operations

cc: Chairman Klein
Commissioner McGaffigan
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

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Letter to W. Shack, from L. Reyes, dated: March 8, 2007

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR OYSTER CREEK GENERATING STATION

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

ACRSR-2233

February 8, 2007

The Honorable Dale E. Klein
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Chairman Klein:

During the 539th meeting of the Advisory Committee on Reactor Safeguards, February 1-3, 2007, we completed our review of the license renewal application for the Oyster Creek Generating Station (OCGS) and the updated Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during meetings on October 3, 2006 and January 18, 2007. During these reviews, we had the benefit of discussions with representatives of the NRC staff and its contractor Sandia National Laboratories (SNL), members of the public, and AmerGen Energy Company, LLC (AmerGen) and its contractors. We also had the benefit of the documents referenced. This report fulfills the requirements of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

RECOMMENDATIONS

1. With the incorporation of the conditions described in Recommendations 2, 3, and 4, the application for license renewal for OCGS should be approved.

2. We concur with the staff's proposal to impose license conditions to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

3. The staff should add a license condition to ensure that the applicant fulfills its commitment to perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner.

4. The staff should add a license condition to ensure that the applicant fulfills its commitment to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

DISCUSSION

The Oyster Creek Generating Station is located in Lacey Township, Ocean County, New Jersey, approximately 2 miles south of the community of Forked River, 2 miles inland from the shore of Barnegat Bay, and 9 miles south of Toms River, New Jersey. The NRC issued the provisional operating license for OCGS on April 9, 1969 and the operating license on July 2,

1991. OCGS is a single unit facility with a single cycle, forced circulation boiling water reactor (BWR)-2 with a Mark 1 containment. The nuclear steam supply system was furnished by General Electric and the balance of the plant was originally designed and constructed by Burns & Roe. The licensed power output is 1930 MWt with a design electrical output of approximately 650 MWe. The applicant, AmerGen requested renewal of the OCGS operating license for 20 years beyond the current license term, which expires on April 9, 2009.

During the 1980s, the licensee discovered corrosion on the outside wall of the OCGS drywell shell. Although some corrosion had occurred in the upper shell region, the majority had occurred in a region near the base of the shell where the shell was partially supported by a sand bed. The licensee determined that water had been leaking through flaws in the refueling cavity liner during refueling operations. This water had migrated down the outside of the drywell shell and into the sand bed. As part of the corrective actions, the licensee removed the sand and applied an epoxy coating to the outside of the shell in the sand bed region. In addition, repairs were made to the refueling pool liner and the concrete drain trough under the refueling seal. These repairs reduced the leakage and routed any leakage to a drain line rather than down the outside of the drywell shell. To further reduce leakage, the licensee applied strippable coatings to the liner during all but one of the subsequent refueling outages. The licensee performed ultrasonic testing (UT) to determine the as-found condition of the drywell shell and performed a structural analysis in 1992 to demonstrate acceptability of the containment in the degraded condition.

The 1992 structural analysis was reviewed and approved by the NRC staff. This analysis included a determination of the stresses in the thinned region under the design pressure loads and an evaluation of the potential for buckling during normal operations and postulated accident conditions. The buckling analysis utilized American Society of Mechanical Engineers (ASME) Code Case N-284, Revision 1. The staff accepted the use of this Code Case in the 1992 analysis. In support of the review of the OCGS license renewal application, the staff had SNL perform a confirmatory structural analysis. Both analyses demonstrated that the drywell shell met the minimum ASME Code requirements for buckling. However, the amount of margin above the Code minimum depended on the applicability of the increase in the buckling capacity due to tensile stresses orthogonal to the applied compressive stresses computed according to the Code Case. During the January 18, 2007 meeting, the Subcommittee requested additional justification for using the increased capacity factor. At our February meeting, Dr. C. Miller, the author of the ASME Code Case, described the technical basis for the Code Case and presented test results to demonstrate that the increased capacity factor was applicable to OCGS. The increased capacity factor used in the 1992 analysis provided by the applicant was based on results for metal cylinders. Dr. Miller showed results of tests conducted on metal spheres which demonstrated that the results for cylinders were conservative for spherical shells. The staff reaffirmed its position that the use of the increased capacity factor is appropriate for the analysis of the OCGS drywell shell. We concur with this position.

The 1992 structural analysis was based on the assumption that the shell is uniformly thinned in the sand bed region. The applicant has committed to perform a 3-D finite-element analysis of the OGCS drywell to determine the margin of the shell in the as-found condition using modern methods. This analysis will provide a more accurate quantification of the margin above the Code required minimum for buckling. The applicant has committed to complete the analysis prior to the period of extended operation. We commend the applicant for this action and would like to be briefed by the staff on the results when they become available. Although it is anticipated that the analysis will demonstrate additional margin above the Code required minimum, the applicant should complete this analysis in a timely manner prior to entering the period of extended operation in order to identify and resolve any unexpected results. The analysis should include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect the Code margins. The staff should impose a license condition to ensure that the applicant completes the analysis prior to entering the period of extended operation.

In 2006, the applicant performed additional UT and visual inspections of the drywell shell. When compared to the previous UT, the 2006 results confirmed that the corrective actions taken in the sand bed region had been effective and that the corrosion had been arrested or at least that the corrosion rates were very low (i.e., within the data scatter). The epoxy coating appeared in very good condition with no evidence of degradation which is also consistent with the conclusion that the corrosion has been effectively arrested. These examinations also demonstrated that the corrosion rate in the upper shell region and the embedded floor regions remained sufficiently low to demonstrate structural integrity during the period of extended operation. The applicant has committed to perform UT and visual inspections of the drywell shell during the period of extended operation. Because of the relatively small margin above the Code minimum against buckling in the sand bed region shown by current analyses, the staff is proposing a license condition to increase the frequency of drywell inspections and UT in the sand bed region to all 10 bays every other refueling outage for the extended period of operation. Increased inspections will result in additional radiation exposure to personnel involved in the inspections. Therefore, the applicant should be allowed to increase the period between inspections if it demonstrates increased margin through analysis or if the ongoing inspections continue to demonstrate that the corrosion has been sufficiently arrested. With this provision, we agree with this license condition.

The 2006 examinations revealed that when the cavity was flooded for refueling, water leakage was still occurring. This leakage of approximately 1 gallon per minute is well within the capacity of the drain as long as the drain system is working properly. The purpose of the drain system is to catch water that may leak past a failed refueling seal or liner and divert the water to sumps, and prevent it from coming into contact with the outside of the drywell shell. Leakage is not expected to occur as part of normal operation with properly maintained equipment and structures. The applicant has committed to continue monitoring for leakage of the refueling cavity liner and other water sources associated with the drywell. The applicant has also committed to complete an engineering study to identify cost-effective repair or replacement options to eliminate the refueling cavity liner leakage. The engineering study will be completed prior to entering the period of extended operation. We agree that efforts should be made to eliminate routine leakage in order to provide increased protection against further degradation. The staff should impose a license condition to ensure the study is completed by the applicant prior to the period of extended operation.

During the 2006 refueling outage, the applicant discovered water in two trenches that had been previously excavated to allow access to and inspection of the inside of the shell in the embedded region. The applicant determined that the water had come from normal operation and maintenance activities. The water had migrated to the trenches due to a blocked drain tube in the sub-pile area and the lack of a seal between the shell and concrete curb. The applicant repaired the drain tube and installed a seal in the gap between the shell and concrete curb. The applicant intends to fill these trenches after two consecutive outages in which no water is observed. Having the trenches open is beneficial for identifying drainage issues, but it increases the risk of additional corrosion because it provides an open area in which water can be trapped against the shell. The staff is proposing a license condition that would require the applicant to leave the trenches open and monitor them during each refueling outage until such time that the applicant can demonstrate that the water sources have been identified and eliminated. We agree with the monitoring of the trenches to ensure the elimination of the sources of water. However, leaving the trenches open longer than necessary increases the risk of future corrosion. Therefore, the applicant should not be unnecessarily delayed in repairing the trenches. With this provision, we agree with the license condition proposed by the staff.

In the updated SER, the staff documents its review of the license renewal application and other information submitted by AmerGen and obtained during an audit and inspections conducted at the plant site. The staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's aging management programs (AMPs); and the identification and assessment of time-limited aging analyses (TLAAs) requiring review.

The OCGS application either demonstrates consistency with the Generic Aging Lessons Learned (GALL) Report or documents deviations from the approaches specified in the GALL Report. The staff reviewed this application in accordance with NUREG-1800, the "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants."

The applicant identified those SSCs that fall within the scope of license renewal. For these SSCs, the applicant performed a comprehensive aging management review. Based on the results of this review, the applicant will implement 57 AMPs for license renewal including existing, enhanced, and new programs. In the SER, the staff concludes that the applicant has appropriately identified SSCs within the scope of license renewal and that the AMPs described by the applicant are appropriate and sufficient to manage aging of long-lived passive components that are within the scope of license renewal. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we agree with this conclusion.

The staff conducted inspections and an audit of the license renewal application. The purpose of the inspections was to verify that the scoping and screening methodologies are consistent with the regulations and are adequately reflected in the application. In addition, the inspectors personally examined selected areas of the sand bed region to verify the condition of the epoxy coating. The audit confirmed the appropriateness of the AMPs and the aging management reviews. Based on the inspections and audit, the staff concluded that these programs are consistent with the descriptions contained in the OCGS license renewal application. The staff also concluded that the existing programs, to be credited as AMPs for license renewal, are generally functioning well and that the applicant has established an implementation plan in its commitment tracking system to ensure timely completion of the license renewal commitments.

The applicant identified those systems and components requiring TLAAs and reevaluated them for 20 more years of operation. Affected TLAAs include those associated with neutron embrittlement, metal fatigue, irradiation-assisted stress corrosion cracking, environmental qualification of electrical equipment, and stress relaxation of hold-down bolts. The staff concluded that the applicant has provided an adequate list of TLAAs. Further, the staff concluded that in all cases the applicant has met the requirements of the license renewal rule by demonstrating that the TLAAs will remain valid for the period of extended operation, or that the TLAAs have been projected to the end of the period of extended operation, or that the aging effects will be adequately managed for the period of extended operation. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we concur with the staff that OCGS TLAAs have been properly identified and that criteria supporting 20 more years of operation have been met.

With the incorporation of the license conditions described in Recommendations 2, 3, and 4, no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) preclude renewal of the operating license for OCGS. The programs established and committed to by AmerGen provide reasonable assurance that OCGS can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public and the NRC should approve the AmerGen application for renewal of the operating license for OCGS.

Sincerely,

/RA/

William J. Shack
Chairman

References:

1. Updated Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station, December 29, 2006.

2. Safety Evaluation Report with Open Items Related to the License Renewal of the Oyster Creek Generating Station, August 18, 2006.

3. Oyster Creek Generating Station- Application for Renewed Operating Licenses, July 22, 2005.

4. Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application, June 20, 2006.

5. Audit and Review Report for Plant Aging Management Reviews and Programs- Oyster Creek Generating Station August 18, 2006.

6. Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application, November 11, 2005.

7. Oyster Creek Generating Station - NRC License Renewal Inspection Report 05000219/2006007, September 21, 2006

8. Memorandum dated December 14, 2006 from Louise Lund to John Larkins, Subject: Review Background Materials for the Meeting of the License Renewal Subcommittee Scheduled on January 18, 2007, Related to the Interim Review of the License Renewal of the Oyster Creek Generating Station. ML063470557

9. Memorandum date December 8, 2006 from Michael P. Gallagher to the U.S. Nuclear Regulatory Commission, Subject: Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating License for Oyster Creek Generating Station. ML063470532

10. Sandia National Laboratories Report "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station," January 2007

11. ASME Code Case N-284-1, "Metal Containment Shell Buckling Design Methods, Class MC, Section III, Division one, March 14, 1995."

12. Letter dated January 31, 2007, from Senator Frank Lautenberg, Senator Robert Menendez, Representative Christopher H. Smith, and Representative Jim Saxton to The ACRS.

13. Letter dated January 31, 2007 from Richard Webster, Rutgers Environmental Law Clinic to the ACRS, regarding the Safety Evaluation Report for Oyster Creek Nuclear Power Plant.

14. Oyster Creek Generating Station-NRC In-Service Inspection and License Renewal Commitment Followup Inspection Report 0500021/2006013, January 17, 2007.

embrittlement, metal fatigue, irradiation-assisted stress corrosion cracking, environmental qualification of electrical equipment, and stress relaxation of hold-down bolts. The staff concluded that the applicant has provided an adequate list of TLAAs. Further, the staff concluded that in all cases the applicant has met the requirements of the license renewal rule by demonstrating that the TLAAs will remain valid for the period of extended operation, or that the TLAAs have been projected to the end of the period of extended operation, or that the aging effects will be adequately managed for the period of extended operation. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we concur with the staff that OCGS TLAAs have been properly identified and that criteria supporting 20 more years of operation have been met.

With the incorporation of the license conditions described in Recommendations 2, 3, and 4, no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) preclude renewal of the operating license for OCGS. The programs established and committed to by AmerGen provide reasonable assurance that OCGS can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public and the NRC should approve the AmerGen application for renewal of the operating license for OCGS.

Sincerely,

/RA/

William J. Shack
Chairman

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OFC	ACRS	ACRS	ACRS	ACRS
NAME	MJunge	CSantos	FGillespie	FPG for WJS
DATE	02/08/07	02/08/07	02/08/07	02/08/07

OFFICIAL RECORD COPY

SEPT. 30, 2006

TO: MR. O. MAYNARD - ACRS -
CHAIRMAN, OYSTER CREEK
LICENSE RENEWAL SUBCOMMITTEE

FROM: JOHN J. BARTON - ACRS CONSULTANT

SUBJ: OYSTER CREEK NUCLEAR
GENERATING STATION - LICENSE
RENEWAL APPLICATION

HAVING COMPLETED MY REVIEW OF
THE OYSTER CREEK LICENSE RENEWAL
APPLICATION, THE NRC SAFETY
EVALUATION REPORT, (WITH OPEN ITEMS),
AND OTHER DOCUMENTS AND REPORTS,
I HAVE THE FOLLOWING QUESTIONS AND/OR
COMMENTS.

1. NRC LICENSING RENEWAL INSPECTION
REPORT, DATED 9/21/06 -
THE OBSERVATION MADE REGARDING
THE TORUS ROOM WALKDOWN

AND THE DUMPING OF THE WATER COLLECTION CONTAINERS JUST PRIOR TO THE NRC INSPECTION OF THE TORUS ROOM IS SOMEWHAT DISTURBING.

FROM THE WORK THAT WAS PERFORMED IN THE EARLY TO MID 1990'S IN MITIGATING THE LEAKAGE, PERFORMING ULTRASONIC TESTS TO DETERMINE DRYWELL PLATE THICKNESS, ANALYZING THE DRYWELL FROM A SAFETY PERSPECTIVE, IT WAS DETERMINED THAT THE DRYWELL WAS NOT A SAFETY ISSUE.

A PROGRAM WAS TO BE IN PLACE TO PERFORM INSPECTIONS AND TO CONTINUE PRACTICES THAT MITIGATED LEAKAGE DURING SUBSEQUENT REFUELING OUTAGES.

FROM MY REVIEW OF THE REPORTS I HAVE RECEIVED, IT APPEARS THAT SOME OF THE FOLLOW ON ACTIONS HAVE NOT BEEN ONGOING. FOR EXAMPLE THERE DOES NOT SEEM TO BE A LEAKAGE MONITORING PROGRAM IN PLACE, AND IT IS NOT APPARENT THAT THE STRIPPABLE COATING HAS BEEN APPLIED DURING REFUELING OUTAGES.

AT THIS POINT IN TIME, I BELIEVE THAT THE ACRS NEEDS TO HEAR WHY THE DRYWELL IS ACCEPTABLE FOR LICENSE RENEWAL.

2. BURIED PIPING INSPECTION PROGRAM

IS THE DIESEL OIL PIPING FROM THE FUEL OIL STORAGE TANK TO THE EMERGENCY DIESEL GENERATOR BUILDING INCLUDED IN THIS PROGRAM?

HOW ABOUT BURIED FIRE PROTECTION SYSTEM PIPING?

HOW MANY BURIED PIPING FAILURES HAVE THERE BEEN ONSITE IN THE PAST 5 YEARS, - 10 YEARS??

3. INSPECTION OF WATER CONTROL STRUCTURES (PG. 3-160 SER)

INSPECTIONS CONDUCTED IN 2001, 2002 NOTED SOME CONCRETE SPALLING/CRACKING OF INTAKE AND DILUTION STRUCTURES. ALSO, WASHOUT OF CANAL EMBANKMENT COATING MATERIAL.

WERE ANY REPAIRS MADE TO CORRECT THESE OBSERVED CONDITIONS?

4. SUPPRESSION CHAMBER (TORUS)
(SER PG. 3-137)

DISCUSSION OF TORUS COATING – STATEMENT THAT THE TORUS AND VENT SYSTEM WERE ORIGINALLY COATED WITH CARBOLINE CARBO-ZINC 11 PAINT.

I DON'T BELIEVE THAT IS THE CURRENT COATING MATERIAL SINCE THE TORUS WAS RECOATED IN THE MID 1980'S. I DIDN'T SEE MENTION OF THE CURRENT COATING MATERIAL.

5. REACTOR INTERNAL COMPONENT'S

THE APPLICANT HAS BEEN ADDRESSING IGSCC AND IASCC ISSUES AND HAS REPLACED OR MADE APPROPRIATE REPAIRS TO CORRECT THESE PROBLEMS.

SINCE AN AGING INSPECTION PROGRAM AS PART OF THE BWR VESSEL INTERNALS PROGRAM IS BEING IMPLEMENTED, I DO NOT HAVE A CONCERN IN THIS AREA.

6. REACTOR VESSEL MATERIALS UPPER SHELF ENERGY REDUCTION DUE TO NEUTRON EMBRITTLEMENT.

THE ANALYSES FOR RX VESSEL CIRCUMFERENTIAL AND AXIAL WELDS HAS BEEN APPROVED BY THE STAFF FOR THE ORIGINAL LICENSE PERIOD OF 40 YEARS.

IF THE APPLICANT DEMONSTRATES THAT THE ANALYSES ARE APPLICABLE FOR THE EXTENDED PERIOD AND THAT ACTIONS WOULD BE TAKEN TO ~~MITIGATE~~ CORRECT ISSUES THAT ARE PROBLEMATIC, I SEE NO REASON THAT THIS ISSUE WOULD PRECLUDE GRANTING THE LICENSE EXTENSION

7. ONE-TIME INSPECTION PROGRAM

THE APPLICANT HAS TAKEN EXCEPTION TO THE USE OF ASME CODE CLASS I SMALL-BORE PIPING PROGRAM, AND HAS PROPOSED A ONE-TIME INSPECTION AGING MANAGEMENT PROGRAM FOR CLASS 1 PIPING LESS THAN OR EQUAL TO NPS 4. THE APPLICANT DESCRIBES HIS PROGRAM AS EXAMINING ONE SOCKET

7 CONT'D.

WELD ELBOW OFF AN ISOLATION CONDENSER DRAIN LINE.

SINCE THIS IS THE ONLY SOCKET-WELD OF CLASS 1 < 4" PIPING TO BE EXAMINED, WHY HAS THE STAFF FOUND THIS TO BE ACCEPTABLE?

8. SCOPING & SCREENING METHODOLOGY (LRA PGS. 2.2-8, 2.2-9) "STRUCTURES"

I DON'T FIND THE "INTAKE TUNNEL" MENTIONED AS EITHER IN-SCOPE OR NOT.

THE INTAKE TUNNEL, IN ADDITION TO PROVIDING ~~WAT~~ CIRCULATING WATER TO THE MAIN CONDENSER WATER BOXES, ALSO PROVIDES A SOURCE OF "SERVICE WATER".

SINCE THE SERVICE WATER SYSTEM HAS BEEN LISTED AS IN-SCOPE, WHY HASN'T THE INTAKE TUNNEL, WHICH HAS PROVISION TO SUPPLY SERVICE WATER, BEEN INCLUDED "IN-SCOPE"?

9. <u>SCOPING AND SCREENING METHODOLOGY</u>

THE APPLICANT HAS INCLUDED THE NITROGEN SUPPLY SYSTEM AS IN SCOPE, AND HAS LISTED THOSE COMPONENTS WITHIN THE SYSTEM IN TABLE 3.3.21.23.

I CANNOT DETERMINE FROM THE INFORMATION CONTAINED IN THIS TABLE WHETHER THE "LIQUID NITROGEN STORAGE TANKS" ARE IN-SCOPE SINCE THE TABLE DESCRIBES TANKS WITH AN INTERNAL ATMOSPHERE OF "DRYGAS".

I ASSUME THESE ARE OTHER TANKS WITHIN THE N_2 SUPPLY SYSTEM.

10. <u>ELECTRICAL SYSTEMS</u>
(SER SECTION 2.5.1.1)

THE STATION BLACKOUT SYSTEM PROVIDES A.C. POWER IN THE EVENT OF LOSS OF ALL A.C. POWER. THE SOURCE OF THIS POWER IS FROM THE FORKED RIVER COMBUSTION TURBINE POWER PLANT. THIS FACILITY IS OWNED, OPERATED AND MAINTAINED BY "FIRST ENERGY COMPANY".

10 CONT'D.

WHAT IS THE LEGAL AGREEMENT IN PLACE THAT ENSURES THAT THE COMBUSTION TURBINE GENERATED ELECTRIC POWER IS AVAILABLE TO OYSTER CREEK WHEN/IF REQUIRED?

HOW DOES THE OYSTER CREEK STAFF MONITOR, OBSERVE MAINTENANCE PRACTICES PERFORMED BY FIRST ENERGY OR ITS CONTRACTORS?

DOES OYSTER CREEK INCLUDE THIS SYSTEM UNDER THE "MAINTENANCE RULE"? IF SO, WHAT IS THE SYSTEM'S CURRENT CLASSIFICATION?

11. GENERAL

WHAT DO THE OYSTER CREEK PERFORMANCE INDICATORS LOOK LIKE?

12. FUSE HOLDERS

I DON'T UNDERSTAND WHY OYSTER CREEK'S FUSE HOLDERS ARE SO DIFFERENT FROM OTHER PLANTS THAT HAVE INCLUDED THEM "IN SCOPE"

13. CONCLUSION

FROM MY REVIEW OF THE DOCUMENTS PROVIDED, I BELIEVE THERE ARE SEVERAL AREAS OF CONCERN THAT NEED TO BE THOROUGHLY UNDERSTOOD, FOLLOWED CLOSELY, AND THAT THE STAFF HAS THE CONFIDENCE THAT THE AGING MANAGEMENT PROGRAMS PROPOSED FOR THESE AREAS WILL EFFECTIVELY MANAGE AGING TO ENSURE SAFE, RELIABLE PERFORMANCE.

THE AREAS ARE:

- DRYWELL CORROSION (I ONLY ADDED THIS DUE TO THE RECENT DISCOVERY OF WATER LEAKAGE AND ~~THE FACT~~ THAT IT APPEARS COMMITTMENTS MADE HAVE NOT BEEN IMPLEMENTED)
- BURIED PIPING - BECAUSE OF HISTORICAL FAILURES AND THE AMOUNT OF BURIED PIPES
- BURIED CABLES - BECAUSE OF HISTORICAL FAILURES

January 17, 2007

Mr. Christopher M. Crane
President and CEO
AmerGen Energy Company, LLC
200 Exelon Way, KSA 3-E
Kennett Square, PA 19348

SUBJECT: OYSTER CREEK GENERATING STATION - NRC IN-SERVICE INSPECTION AND LICENSE RENEWAL COMMITMENT FOLLOWUP INSPECTION REPORT 05000219/2006013

Dear Mr. Crane:

On December 6, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Oyster Creek Generating Station. The inspection was a review of AmerGen's in-service inspections, including a followup inspection of your license renewal commitments relevant to the Fall 2006 outage related to the drywell shell and torus. The enclosed report documents the inspection results, which were discussed on November 16, 2006, and again on January 16, 2007, with Mr. T. Rausch, Senior Vice President, Oyster Creek, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. In addition, this inspection also examined the plant activities and documents that supported license renewal commitments of Oyster Creek Generating Station drywell shell and torus. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, no findings of significance were identified. Also, the NRC staff determined that there were no safety significant conditions with respect to the primary containment that would prohibit plant startup and there was reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle.

For the license renewal commitments reviewed during this inspection, the inspectors determined that AmerGen was adequately implementing those commitments. This inspection report does not provide an overall NRC conclusion about acceptability of programs for license renewal; final technical conclusions will be provided by the NRC Office of Nuclear Reactor Regulation.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web Site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Richard J. Conte, Chief
Engineering Branch 1
Division of Reactor Safety

Docket No. 50-219
License No. DPR-16

Enclosure: Inspection Report 05000219/2006013
w/Attachment: Supplemental Information

cc w/encl:
Chief Operating Officer, AmerGen
Site Vice President, Oyster Creek Nuclear Generating Station, AmerGen
Plant Manager, Oyster Creek Generating Station, AmerGen
Regulatory Assurance Manager, Oyster Creek, AmerGen
Senior Vice President - Nuclear Services, AmerGen
Vice President - Mid-Atlantic Operations, AmerGen
Vice President - Operations Support, AmerGen
Vice President - Licensing and Regulatory Affairs, AmerGen
Director Licensing, AmerGen
Manager Licensing - Oyster Creek, AmerGen
Vice President, General Counsel and Secretary, AmerGen
T. O'Neill, Associate General Counsel, Exelon Generation Company
J. Fewell, Assistant General Counsel, Exelon Nuclear
Correspondence Control Desk, AmerGen
J. Matthews, Esquire, Morgan, Lewis & Bockius LLP
Mayor of Lacey Township
K. Tosch, Chief, Bureau of Nuclear Engineering, NJ Dept of Environmental Protection
R. Shadis, New England Coalition Staff
N. Cohen, Coordinator - Unplug Salem Campaign
E. Gbur, Chairwoman - Jersey Shore Nuclear Watch
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance
P. Baldauf, Assistant Director, Radiation Protection and Release Prevention, State of NJ

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J. Lamb, RI OEDO
H. Chernoff, NRR
E. Miller PM, NRR
T. Valentine, Backup PM (Interim), NRR
M. Young, OGC
ROPreports@nrc.gov
Region I Docket Room (with concurrences)
A. Blough, DRS
M. Gamberoni, DRS
R. Conte, DRS
J. White, DRS
P. Kaufman, DRS

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DATE	01/08/07	01/08/07	01/08/07	01/17/07	

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NAME					
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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-219
License No:	DPR-16
Report No:	05000219/20006013
Licensee:	AmerGen Energy Company, LLC
Facility:	Oyster Creek Generating Station
Location:	Forked River, New Jersey
Dates:	October 16 - December 6, 2006
Inspectors:	P. Kaufman, Team Leader, Senior Reactor Inspector, Division of Reactor Safety (DRS) T. O'Hara, Reactor Inspector, DRS M. Ferdas, Senior Resident Inspector, Oyster Creek, Division of Reactor Projects (DRP) S. Chaudhary, Health Physicist, Division of Nuclear Materials Safety (DNMS) R. Fuhrmeister, Senior Project Engineer, DRP
NRR Reviewers:	H. Ashar, Technical Reviewer, NRR S. Samaddar, Technical Reviewer, NRR E. Miller, Project Manager, NRR
Approved By:	Richard J. Conte, Chief Engineering Branch 1 Division of Reactor Safety

Enclosure

SUMMARY OF FINDINGS

IR 05000219/2006013; 10/16/2006 - 12/6/2006, Oyster Creek Generating Station; In-service Inspection, including License Renewal Commitment Followup inspection activity.

This inspection of in-service inspection activities, including license renewal commitment followup activities, was performed by four regional office inspectors and one resident inspector. There were no safety significant conditions with respect to the primary containment that would prohibit plant startup and there is reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

No findings of significance were identified.

B. Licensee-Identified Violations

None.

Executive Summary

The NRC staff conducted a baseline inspection of in-service inspection (ISI) activities, as well as an extensive onsite review of AmerGen's actions to evaluate: (1) the structural integrity of the primary containment relative to the existing licensing basis in consideration of any actual or potential corrosion, and (2) the significance of water that was identified in two trenches located inside the drywell during the October 2006 outage at the Oyster Creek Nuclear Generating Station (OCNGS). The NRC review involved a multi-week inspection of AmerGen's ISI program, and included an assessment of license renewal commitments for the outage and AmerGen's technical evaluation and structural integrity reports associated with the design basis for the primary containment (drywell). In accordance with the NRC's agreement with the State of New Jersey, state engineers observed portions of the NRC's staff review. Based on the results of the NRC's inspection activities, the NRC concluded that: (1) ISI activities were adequately performed, (2) there were no safety significant conditions with respect to the primary containment that would prohibit plant startup, and (3) there is reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle. The following provided additional background and details pertaining to the primary containment.

In the mid-1980s, GPU Nuclear (as licensee) identified corrosion of the shell of the OCNGS containment drywell in the sandbed region. Initial licensee actions were not effective in arresting corrosion, and in 1992, all sand was removed from the sandbed region and the accessible exterior surfaces of the drywell shell were cleaned and coated with an epoxy paint. Ultrasonic test (UT) measurements of the drywell shell thickness were taken in 1992 and 1996. UT results indicated that the corrosion had been effectively arrested.

On October 16, 2006, OCNGS shut down for a refueling and maintenance outage. Scheduled outage work included expanded in-service inspection of the drywell shell thickness (through UT testing) and material condition of accessible internal and external portions of the drywell (via visual testing).

During the Fall 2006 outage, AmerGen Energy, LLC (the current licensee) obtained UT measurements of drywell shell thickness at many of the same locations as previously examined in the 1990s. UT measurements were taken in the former sandbed region, both inside and outside the drywell, and in two trenches cut into the concrete floor in two bays inside the drywell. These trenches permit access to the embedded portion of the drywell shell below the sandbed region. In addition, UT measurements were taken at various levels of the drywell shell from the inside (the upper drywell shell is not accessible in these areas from the outside due to the concrete shield building).

The NRC staff inspection throughout the outage focused on:

1) Non-destructive examination results of the drywell shell and torus and related AmerGen evaluations.
2) AmerGen's efforts to identify and mitigate the source of water which accumulated in the trenches in the concrete floor inside the drywell. These efforts included tracer dye testing of the drywell leakage collection trough inside the reactor pedestal, inspection of the drywell sump, inspection and repair of the leakage collection trough, and caulking of the joint between the concrete drywell floor and the steel drywell shell.
3) Structural integrity of the concrete drywell floor and the condition of the embedded portion of the drywell shell.
4) The potential impact from various repairs to the containment on the design and licensing bases of the drywell.

The overall results of the staff's observations and review were:

1) All UT results were greater than the AmerGen calculated minimum ASME code required thickness for various plates that form the drywell shell.
2) There were no adverse conditions associated with the epoxy coating on the outside of the drywell shell in the former sandbed region.
3) Repairs performed by Amergen in and around the trough within the reactor vessel pedestal area did not result in any adverse conditions.
4) The water discovered in the drywell trenches had no adverse impact on the structural integrity of the concrete floor or the potential for corrosion of the embedded portion of the drywell shell. AmerGen has taken actions to prevent further accumulation of water in this area.
5) There were no adverse conditions with respect to the drywell or torus structural integrity that would preclude restart.

Based on a review of the technical information, the NRC staff determined that AmerGen had sufficient justification to restart OCNGS.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R08 In-service Inspection Activities (71111.08G - 1 Sample)

a. Inspection Scope

The inspectors observed non-destructive examination (NDE) activities and reviewed documentation of NDE and repair activities. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation could result in a significant increase in the risk of core damage. The direct observations and documentation reviews were performed to verify that NDE activities were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1995 Edition, with the 1996 Addenda, 10CFR 50.55a, Codes and Standards, Boiling Water Reactor Vessel Internals Program recommendations, and station implementing procedures. The inspectors reviewed a sample of NDE reports initiated to document the performance and record results of in-service inspection (ISI) examinations completed during the current refueling outage 1R21 as well as those since the last refueling outage 1R20. The inspectors also evaluated the licensee's effectiveness in resolving relevant indications identified during ISI activities. Documents reviewed for this inspection are listed in the attachment.

The inspectors reviewed several NDE examinations, including liquid penetrant (PT), UT, and radiographic (RT) examination data records, to verify the effectiveness of the licensee's program for monitoring degradation of risk-significant piping structures, systems, and components. The inspectors examined the licensee's evaluation and disposition for continued operation, without repair or rework, of non-conforming conditions identified during ISI activities by review of AR 547617 and General Electric INR 01R21 IVVI-06-08, which documented some indications during IVVI examinations on the inside diameter surface of core shroud vertical weld SHD V-09. The indications are horizontal (transverse to the SHD V-09 weld). These indications had previously been identified and documented in 1996. Measurements were taken to evaluate the condition observed this outage (1R21) to those identified in 1996. The inspector verified that the licensee comparison of the indications found during 2006 correlated closely with the indications identified and documented in 1996. The indications meet the requirement of the program.

The inspectors reviewed one ASME Section XI code repair and its associated NDE from the 1R21 refueling cycle. Specifically, the inspectors reviewed the NDE associated with the welding repair activities performed per work order C2013778 on 3-inch control rod drive return line weld NC-2-2, which is a ferritic steel to austenitic steel joint with austenitic weld material. This categorizes the weld as a dissimilar metal weld. The weld is located between valve V-15-28 and V-15-29 inside the drywell. AmerGen selected this weld for UT examination to support license renewal. The inspectors reviewed initial UT data examination report number 1R21-217, data sheet number D-218 of weld NC-2-2, which documented a recordable axial indication during a 45° RL scan in the circumferential direction during the current 1R21 refueling outage. The indication started adjacent to the root on the ferritic side of the weld and had an estimated through-wall height of 50 percent. The inspectors verified that AmerGen implemented corrective actions to replace a section of the piping between the two valves and sent the pipe section with the weld flaw indication for failure analysis to determine the failure mechanism. After the section of piping was replaced and repairs completed, the inspectors reviewed the liquid penetrant examination and radiographic records of the new welds NC-2-2A and NC-2-2B. This review was performed to verify that the activities associated with welding on ASME Class I or II components were in accordance with applicable ASME code requirements.

The inspectors performed direct field observations of UT examination of "B" Isolation Condenser 12-inch pipe welds NE-1-220 and NE-1-221 per work order C2012158, UT examination of N8 closure head nozzle reactor head vent to shell NR02 5-576 weld per work order C2012402, documented in UT examination report number 1R21-166, sheet D-107 and PT examination of N8 nozzle to flange reactor head NR02 6-576 weld, documented in examination report number 1R21-163, sheet PT-004. The review was performed to evaluate examiner skills and performance; examination technique; assess contractor oversight activities; and to verify licensee and contractor ability to identify and characterize observed indications.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Other - License Renewal Commitment Followup (71003)

.1 License Renewal Commitment Followup Inspections

a. Inspection Scope

The license renewal portion of this inspection was performed in accordance with the guidance in IP 71003, which is a part of the NRC Inspection Manual Chapter 2516, License Renewal Program. The inspectors verified that the license renewal commitments contained in AmerGen Letters 2130-06-20284 (4/4/06), 2130-06-20358 (7/7/06) and 2130-06-20414 (10/20/06) were met. All of the commitments dealt with inspections and actions necessary to ensure structural integrity of the primary containment (drywell and torus) at Oyster Creek.

The following commitments were verified to be completed during the October 2006 1R21 refueling outage:

(1) Visual inspection of the epoxy coating on the exterior of the drywell in the former sandbed region.
(2) UT thickness measurements (internal and external) of the drywell shell in the sandbed region.
(3) The application of a strippable coating to the reactor cavity liner before beginning refueling operations during the October 2006 1R21 refueling outage.
(4) The reactor cavity seal drains and the drywell sand bed region drains were monitored for water leakage during the October 2006 1R21 refueling outage.
(5) Visual inspection of the drywell shell in the access trenches. Upon noting water in the trenches, AmerGen completed a technical evaluation of the unexpected condition. AmerGen determined that structural integrity was not affected by the presence of this water.
(6) Visual inspection of the coating on the inside of the torus. A number of shallow pits were noted in the metal and many were repaired in accordance with plant specifications and repair procedures.
(7) Conducted UT thickness measurements at the 23'6" and 71'6" elevations of the drywell at the same locations which had been previously measured.

The inspectors completed confined space training and sandbed bay mock-up training in preparation for observing the licensee's inspections in the drywell shell sandbed bays (Bays 1, 11, and 13). Additionally, the inspectors reviewed inspection data sheets and video records of the inspections of all 10 sandbed bays. The inspectors verified that the sandbed bay external conditions were accurately described and measured on the AmerGen data sheets in the context of the Aging Management Program for the drywell and torus (see below ASME, Section XI, Subsection IWE and Protective Coating Monitoring and Maintenance).

<u>ASME, Section XI, Subsection IWE Program</u>

Monitoring of the condition of the primary containment drywell is accomplished through the licensee's ASME Section XI, Subsection IWE monitoring program. Additionally, if the plant obtains a renewed license, the Aging Management Program (AMP) for the primary containment drywell and torus will use the same program.

The ASME, Section XI, Subsection IWE Program is an existing program modified for the purpose of managing the aging effects in the drywell containment system at Oyster Creek. ASME Section XI, Subsection IWE provides for inspection of primary containment components, including steel containment shells. The aging effects are managed by periodic visual inspections and periodic ultrasonic testing wall thickness measurements. Additionally, AmerGen will conduct monitoring of leakage from the drywell sand bed region drains as an additional method to detect conditions which indicate further corrosion may occur. Analysis and evaluation of the visual and ultrasonic examinations are given credit for managing the effects of aging.

The inspectors reviewed supporting documentation and interviewed AmerGen personnel to confirm the adequacy of the license renewal conclusions of this program.

The inspectors reviewed the licensee's UT inspection procedures, interviewed NDE supervisors and observed field collection and recording of UT data in accordance with the approved procedures. The inspectors also reviewed the UT qualifications of selected data collection technicians.

Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program is an existing program credited with managing the aging effects on the internal and external surfaces of the torus and the condition of the drywell in the sandbed region. The aging effects are managed by visual inspections of the protective coatings on each component, and examination, evaluation and repair of all coating defects observed.

The inspectors reviewed supporting documentation and interviewed applicant personnel to confirm the adequacy of the license renewal conclusions from the visual inspections conducted in the drywell and torus.

The inspectors reviewed the licensee's VT inspection procedures, interviewed NDE supervisors and observed field collection and recording of VT data in accordance with the approved procedures. The inspectors also reviewed the VT qualifications of selected data collection technicians.

The inspectors reviewed the VT inspection data sheets for the drywell shell and torus inspections conducted during the October 2006, 1R21 refueling outage. The inspectors reviewed the VT inspection data sheets for the torus internal coating inspections conducted during the October 2006, 1R21 refueling outage. The inspectors verified that the VT results for the drywell sandbed regions indicated no degradation of the epoxy coating.

The inspectors reviewed documented evidence that strippable coating of the refueling channel had been applied during October 2006 1R21 refueling outage. This strippable coating is used as a measure to limit or prevent water leakage during refueling operations.

Structural Review

During the planned structural review, AmerGen removed the ternporary grout in the trenches inside the drywell which were previously dug out to expose the shell in the sandbed region. The structural review was expanded when water was unexpectedly discovered in the trenches. Accordingly, the inspectors monitored licensee actions and reviewed drawings, visually examined the condition of concrete in the drywell floor slab, and reviewed chemical analysis of the water sampled from one of the trenches. The inspectors reviewed the 50.59 screen associated with repairs to the drywell floor, trough, and curb (interface between the concrete floor slab and the drywell shell) and performed a walkdown of the drywell to ensure that the repairs were made in accordance with written instructions. The inspectors attended the Station Onsite Review Committee meeting on November 4, 2006, that discussed AmerGen's technical evaluation of the drywell issue. The inspectors performed inspections of the water collection bottles associated with the sandbed drains on October 19, 23, 27, and November 1, 2006, to ensure no water was being detected.

b. Findings and Observations

No findings of significance were identified.

Observations

The inspectors noted that AmerGen commitments for the drywell and torus were met; a more detailed listing of observations (factual details) are noted below. With respect to the water in the trenches, the most likely source was found and conditions inside the drywell as a result of the issue were appropriately evaluated by AmerGen (additional factual details are noted in Commitment No. (5) below). Overall, the team determined that there were no safety significant conditions with respect to the primary containment that would prohibit plant startup and that there is reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle.

Also, during this inspection, the inspectors noted improvement in AmerGen's procedure controls governing VT and UT inspections and data analysis. The documentation of inspection results, the presence of acceptance criteria, and the disposition and analysis of the data were significantly improved over past inspections.

Commitments (1), (2) and (7) (Commitment numbers related to the listing at the start of this report section)

The inspectors reviewed the UT wall thickness data sheets for the drywell shell from 1R21 refueling outage which documented shell thickness measurements. The UT results indicate that the shell thickness was accurately reported by the licensee. The inspection procedures contained appropriate criteria for reporting nonconforming conditions and that all nonconforming data were reported and evaluated by cognizant engineering personnel. AmerGen subsequently verified that design minimum wall thicknesses, required for pressure loads and for buckling loads, remain valid until the next refueling outage in 2008.

The inspectors noted that coating inspections performed on the outside surface of the drywell shell during 1R21 in 2006 did not identify any blistering or degradation of the coating. The inspectors determined that AmerGen will perform an inspection of the drywell shell during the 1R22 Oyster Creek refueling outage scheduled for 2008 based on review of AmerGen letter 2103-06-20426, dated December 3, 2006.

The AmerGen aging management program, which includes both the ASME Section XI, Subsection IWE program and the Protective Coatings Monitoring and Maintenance, will address structural integrity beyond 2008, subject to NRC staff safety evaluation review.

Commitment (3)

The inspectors reviewed documented evidence that strippable coating of the refueling channel had been applied during October 2006 1R21 refueling outage.

Commitment (4)

The inspectors reviewed the licensee's procedure for inspections of the sandbed drains and the reactor cavity seal drains. The inspectors also reviewed and verified records which showed that the licensee inspected the sandbed drains and the reactor cavity seal drains throughout the outage. The inspectors also performed independent inspections of the water collection bottles associated with the sandbed drains on October 19, 23, 27, and November 1, 2006, to ensure no water was being detected.

Commitment (5)

Presence of Water in the Drywell Concrete Slab

Water was discovered in the drywell trenches of bay 5 and bay 17 after removal of the grout by AmerGen during the current 1R21 refueling outage. The grout was being removed in order to perform a license renewal commitment inspection. The presence of the water was not expected by AmerGen. The condition was entered in the corrective action process and AmerGen carried out the following actions:

(1) Conducted walkdowns of the structure and examined drawings to determine the source of the water. The actual source of the water was not positively determined.
(2) Sampled the water and performed dye tracer testing to determine the source of the water.
(3) Removed the water from the trenches and conducted the planned UT thickness measurements of the drywell shell in the trenches.
(4) Conducted technical engineering evaluations by an industry corrosion expert and AmerGen engineering personnel to assess the structural integrity of the drywell concrete slab given the presence of the water.
(5) Installed a seal between the concrete curb and the drywell shell to prevent water from entering the drywell shell-to-concrete gap.
(6) Made a repair to the drywell trough drain, which eliminated leakage path into the concrete/drywell liner gap.
(7) Removed an additional 5" of concrete from the trench in Bay 5 and collected more UT thickness data in a previously unmeasured area.
(8) Performed and documented a VT inspection of the drywell shell in the trenches.

Clearing of the trough drain and repair of the trough routed some leakage away from the drywell shell. AmerGen's root cause evaluation did not determine the exact source of the water in the drywell trenches. Operational leakage via the unsealed concrete to drywell shell interface or control rod drive leakage could not be ruled out. AmerGen had a technically justifiable logic as to why the major source of the water was the trough with concrete flaws, but the associated technical evaluation lacked details with respect to the basis and elimination of other potential sources of water.

Drywell Concrete Floor

The inspectors observed that the condition of the concrete outside the reactor pedestal was in good condition, there was no obvious indication of concrete deterioration, e.g., disintegration, spalling, chipping and/or erosion.

The floor within the reactor pedestal annulus is overlaid by approximately 7-inch thick wearing surface to provide a crown for drainage towards the drainage trough around the pedestal. This wearing slab is textured with exposed rounded gravel which is generally used to protect surfaces from damaging effects of long time/sustained drip and/or flow of any liquid/water on structural surfaces. There was a visible crack in this overlay that appeared to extend the full depth of the overlay; however, the crack did not appear to be active, and was filled with fine granular material. Such loose, fine materials are not uncommon and/or unusual in textured finish surfaces. Also, the overlay is not reinforced, and does not have any structural significance.

Based on observation of the concrete floor, the structural integrity of the concrete is not impaired or negatively affected by the construction joint in the concrete overlay inside the pedestal annulus.

During cleaning of the troughs, a glass bottle was found imbedded in the side of the trough near the drywell sump pumps. The object was removed in pieces from the concrete. There appeared to be a leakage path from where the bottle was removed. Based on NRC staff review, the effect of this small void on the strength, durability, and functionality of slab is negligible.

Drywell Steel Shell Corrosion

The drywell steel shell is embedded between the structural reinforced concrete base and the drywell floor, which also is reinforced structural concrete. Therefore, the service environment of the steel liner is similar to embedded rebar or any other carbon steel embedment.

There is sufficient technical literature and public domain studies available to support a conclusion that carbon steel embedded in highly alkaline material does not corrode in general service, unless the alkaline environment is radically altered and a sustained acidic environment is created. Availability of chloride ions also affects and accelerates corrosion.

With available information, it appears that the drywell shell is not in a corrosive environment, thus active corrosion is unlikely. The most likely source of water inside the drywell during operation is condensate water, which does not contain corrosive materials.

Overall, the inspection team did not disagree with AmerGen's conclusion and reasons that no significant corrosion of the embedded drywell shell was evident or anticipated:

(1) The water in contact with the drywell shell had a high pH as a result of being in contact with the adjacent concrete.
(2) Water entering the slab-to-shell area will have to migrate through concrete and will also become high pH water; corrosion is minimal in high pH conditions.
(3) Any exposure of the drywell to an oxygen-rich environment will be limited due to containment inerting with nitrogen during operations.

Commitment (6)

The VT inspection procedures contained appropriate criteria for reporting nonconforming conditions and for dispositioning nonconforming conditions. The VT results for the torus internal coating indicate continuing degradation of the coating. Of the 959 coating blisters identified by AmerGen, they repaired 881 coating blisters that exceeded the administrative repair criteria and the others were evaluated as satisfactory. AmerGen then conducted a structural integrity verification calculation of the observed conditions, which demonstrated structural integrity until the next refueling outage in 2008. The AmerGen aging management program will address structural integrity beyond 2008, subject to NRC staff safety evaluation review.

4OA2 Other - Identification and Resolution of Problems

.2 Identification and Resolution of Problems - In-service Inspection and License Renewal Commitment Followup (71111.08 & 71003)

a. Inspection Scope

The inspectors reviewed the Issue Reports listed in Attachment 1 associated with ISI, including license renewal commitment followup inspection activities. The inspectors verified that problems identified by these documents were properly characterized in AmerGen's corrective action reporting system, and that applicable causes and corrective actions were identified commensurate with the safety significance of the in-service inspection deficiency.

b. Findings

No findings of significance were identified.

Observations

During the inspectors' review of Issue Reports (IRs) written during this inspection, the inspectors noted that, on several occasions, inspectors questioned AmerGen personnel on the need to enter specific conditions in the AmerGen corrective action process. Subsequently, all important conditions were entered into the corrective action process.

Also, the inspectors provided several technical comments and corrections on the draft technical evaluations AR A2152754-06 and AR A2152754-09, which evaluated the unexpected water in the drywell trenches. As a result of these comments provided by the inspector, AmerGen made substantive changes to the evaluations. This indicated some missed opportunities for AmerGen supervisory review to impart attention to detail.

The inspectors noted that the presence of water in the bay 5 and bay 17 trenches inside the drywell had been reported in Structural Inspection Reports in 1992 and 1994. The Structural Inspection Report from 1994 (dated January 3, 1995) indicates that the rectification of the situation will require prevention of water from reaching the trenches with proven material(s). However, this condition and the evaluation were not addressed by the corrective action process in effect at the time. More importantly, during the October 2006 1R21 refueling outage, the issue was entered into the IR process using the current standards for timeliness of identification. The AmerGen resultant evaluation in 2006 determined no significant effect on primary containment.

Further, AmerGen review of inspection results performed during the October 2006 refueling outage of the internal surface of the drywell shell caused a re-evaluation of the license renewal application with respect to water in the trenches excavated in the concrete floor. AmerGen determined that an environment/material/aging effect combination exists that had not been previously included in the Oyster Creek license renewal application. AmerGen's letter to the NRC (2103-06-20426), dated December 3, 2006, addresses this issue along with the results of an extent-of-condition review. Also, AmerGen has identified additional aging management activities that will be included in the aging management programs associated with the drywell. This additional information provided by AmerGen is being reviewed by the NRC Office of Nuclear Reactor Regulation staff similar to additional information provided by applicants when the NRC staff issues requests for additional information, that is, subject to review in a final safety evaluation report.

4OA6 Meetings, including Exit

The inspectors met with Mr. T. Rausch, Oyster Creek Generating Station Vice President and other members of the licensee's staff at the conclusion of the onsite inspection on November 16, 2006, and again on January 16, 2007, to summarize the inspection results. The end of the inspection was extended to December 6, 2006, to include a review of AmerGen's letter to the NRC (203-06-20426), dated December 3, 2006. Proprietary information was provided to the inspectors during this inspection, but licensee representatives indicated that it may be released.

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Rausch, Senior Vice President, Oyster Creek
J. Randich, Plant Manager, Oyster Creek
C. Lambert, Vice President, Engineering, Exelon Nuclear
M. Coyne, Vice President, Operations, Exelon Nuclear
M. Gallagher, Vice President, License Renewal
G. Harttraft, ISI Program Manager
H. Ray, Engineering Manager, Oyster Creek
T. Quintenz, Site Lead Engineer, LR Project
J. Hufnagel, Licensing Lead, LR Project
F. Polaski, License Renewal Manager
J. Kandasamy, Manager, Regulatory Assurance
K. Barnes, Senior Regulatory Affairs Engineer
M. McAllister, NDE Level III Examiner, Oyster Creek
C. Hawkins, NDE Level III Examiner, Peach Bottom
F. Ray, Manager Mechanical/Structural Design, Oyster Creek
S. Niogi, Senior Engineer, Mechanical/Structural Engineering, Oyster Creek
P.Tamburo, Senior Engineer, Mechanical/Structural Engineering, Oyster Creek

New Jersey State Department of Environmental Protections

R. Pinney, Nuclear Engineer, Bureau of Nuclear Engineering (BNE)
D. Zannoni, Supervisor, Bureau of Nuclear Engineering (BNE)

LIST OF DOCUMENTS REVIEWED

Section 1RO8: In-service Inspection and License Renewal Commitments

NDT Examination Reports

UT Examination Report Number 1R21-217, Sheets D-218, D-D219, D-220, D-221, and D-223, NC-2-0002 C/S Pipe to S/S Pipe
UT Examination Report Number 1R21-166, Sheet D-107, N8 Closure Head Nozzle Reactor Head Vent to Shell Weld NR02 5-576
PT Examination Report Number 1R21-163, Sheet PT-004, N8 Nozzle to Flange Reactor Head Weld NR02 6-576

QP10.09-OCNGS1R21, Record No.1; 10/28/06; Qualitative Inspection Record & Quantitative Evaluation of Metal Loss Record
Video Tape; 10/21 - 10/25/06; Before & After Cleaning of Debris in Bay 7 Sandbed bay
Video Tape; 10/19/06; Bay 11 Sandbed drain Partial Blockage
Video Tape; 10/21/06; Bay 15 Sandbed General Condition
Video Tape; 10/21/06; Bay 19 Sandbed General Condition
GPU Memorandum Dated 1/28/93; Inspection Of Drywell Sand Bed Region And Access Holes, Mr. K. L. Whitmore
Data Sheet 21R-158, VT-1 Drywell Sump, 10/29/06
UT Measurement Data Sheet #1R21LR-001, Page 1 of 5 Internal Drywell UT Inspections
UT Measurement Data Sheet #1R21LR-001, Page 2 of 5 Internal Drywell UT Inspections
UT Measurement Data Sheet #1R21LR-001, Page 3 of 5 Internal Drywell UT Inspections
UT Measurement Data Sheet #1R21LR-001, Page 4 of 5 Internal Drywell UT Inspections
UT Measurement Data Sheet #1R21LR-001, Page 5 of 5 Internal Drywell UT Inspections
UT Measurement Data Sheet #1R21LR-028, Page 1 of 1 Internal UT Inspections
UT Measurement Data Sheet #1R21LR-026, Page 1 of 2 Internal UT Inspections
UT Measurement Data Sheet #1R21LR-026, Page 2 of 2 Internal UT Inspections
UT Measurement Data Sheet #1R21LR-002, Page 1 of 2 Internal UT Inspections
UT Measurement Data Sheet #1R21LR-002, Page 2 of 2 Internal UT Inspections
UT Measurement Data Sheet #1R21LR-033, Page 1 of 1 Internal UT Inspections, 71'6" El
UT Measurement Data Sheet #1R21LR-034, Page 1 of 1 Internal UT Inspections, 71'6" El
UT Measurement Data Sheet #1R21LR-029, Page 1 of 1 Internal UT Inspections, 23'6" El
UT Measurement Data Sheet #1R21LR-030, Page 1 of 1 Internal UT Inspections, 23'6" El
UT Measurement Data Sheet #1R21LR-020, Page 1 of 5 Internal UT Inspections
UT Measurement Data Sheet #1R21LR-022, Page 1 of 2 External UT Inspections, Bay 1
UT Measurement Data Sheet #1R21LR-022, Page 2 of 2 External UT Inspections, Bay 1
UT Measurement Data Sheet #1R21LR-012, Page 1 of 2 External UT Inspections, Bay 3
UT Measurement Data Sheet #1R21LR-012, Page 2 of 2 External UT Inspections, Bay 3
UT Measurement Data Sheet #1R21LR-019, Page 1 of 2 External UT Inspections, Bay 5
UT Measurement Data Sheet #1R21LR-019, Page 2 of 2 External UT Inspections, Bay 5
UT Measurement Data Sheet #1R21LR-005, Page 1 of 2 External UT Inspections, Bay 7
UT Measurement Data Sheet #1R21LR-005, Page 2 of 2 External UT Inspections, Bay 7
UT Measurement Data Sheet #1R21LR-006, Page 1 of 2 External UT Inspections, Bay 9
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UT Measurement Data Sheet #1R21LR-008, Page 1 of 2 External UT Inspections, Bay 11
UT Measurement Data Sheet #1R21LR-008, Page 2 of 2 External UT Inspections, Bay 11
UT Measurement Data Sheet #1R21LR-010, Page 1 of 2 External UT Inspections, Bay 13
UT Measurement Data Sheet #1R21LR-010, Page 2 of 2 External UT Inspections, Bay 13
UT Measurement Data Sheet #1R21LR-015, Page 1 of 2 External UT Inspections, Bay 15
UT Measurement Data Sheet #1R21LR-015, Page 2 of 2 External UT Inspections, Bay 15
UT Measurement Data Sheet #1R21LR-021, Page 1 of 2 External UT Inspections, Bay 17
UT Measurement Data Sheet #1R21LR-021, Page 2 of 2 External UT Inspections, Bay 17
UT Measurement Data Sheet #1R21LR-020, Page 1 of 2 External UT Inspections, Bay 19
UT Measurement Data Sheet #1R21LR-020, Page 2 of 2 External UT Inspections, Bay 19
IWE Data Sheet #1R21LR-017, Page 1 of 4, Sand Bed External VT Inspection, Bay 1
IWE Data Sheet #1R21LR-017, Page 2 of 4, Sand Bed External VT Inspection, Bay 1
IWE Data Sheet #1R21LR-017, Page 3 of 4, Sand Bed External VT Inspection, Bay 1

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IWE Data Sheet #1R21LR-013, Page 1 of 6, Sand Bed External VT Inspection, Bay 3
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IWE Data Sheet #1R21LR-014, Page 3 of 4, Sand Bed External VT Inspection, Bay 5
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IWE Data Sheet #1R21LR-004, Page 1 of 6, Sand Bed External VT Inspection, Bay 7
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IWE Data Sheet #1R21LR-009, Page 4 of 4, Sand Bed External VT Inspection, Bay 13
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IWE Data Sheet #1R21LR-011, Page 5 of 6, Sand Bed External VT Inspection, Bay 17
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IWE Data Sheet #1R21LR-018, Page 1 of 6, Sand Bed External VT Inspection, Bay 19
IWE Data Sheet #1R21LR-018, Page 2 of 6, Sand Bed External VT Inspection, Bay 19
IWE Data Sheet #1R21LR-018, Page 3 of 6, Sand Bed External VT Inspection, Bay 19
IWE Data Sheet #1R21LR-018, Page 4 of 6, Sand Bed External VT Inspection, Bay 19
IWE Data Sheet #1R21LR-018, Page 5 of 6, Sand Bed External VT Inspection, Bay 19
IWE Data Sheet #1R21LR-018, Page 6 of 6, Sand Bed External VT Inspection, Bay 19

IWE Data Sheet #1R21LR-003, Page 3 of 6, Sand Bed External VT Inspection, Bay 9
IWE Data Sheet #1R21LR-003, Page 4 of 6, Sand Bed External VT Inspection, Bay 9
UT Measurement Data Sheet #1R21LR-027, Page 1 of 2 Trench UT Inspections, Bays 5 & 17
UT Measurement Data Sheet #1R21LR-027, Page 2 of 2 Trench UT Inspections, Bays 5 & 17
UT Measurement Data Sheet #1R21LR-025, Page 1 of 4 Trench UT Inspections, Bays 5 & 17
UT Measurement Data Sheet #1R21LR-025, Page 2 of 4 Trench UT Inspections, Bays 5 & 17
UT Measurement Data Sheet #1R21LR-025, Page 3 of 4 Trench UT Inspections, Bays 5 & 17
UT Measurement Data Sheet #1R21LR-025, Page 4 of 4 Trench UT Inspections, Bays 5 & 17
IWE Data Sheet #1R21LR-023, Page 1 of 3, VT Trench Inspection, Bays 5 & 17
IWE Data Sheet #1R21LR-031, Page 1 of 2, VT Trench Inspection, Bays 5 after concrete removal
IWE Data Sheet #1R21LR-031, Page 2 of 2, VT Trench Inspection, Bays 5 after concrete removal

Repair-Replacement

C2013778, Replace Pipe CRD Return, dated 10/29/2006
Report No. 05-0209, 2/25/05; Radiation and Design Basis Accident Testing Of Thin Film Technology's BIO-DUR 561
WO R2077340,Torus Coating Repair Record Bay 1, 14/14 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 2, 10/13 indications repaired, 10/27/06
WO R2077340,Torus Coating Repair Record Bay 3, 33/33 indications repaired, 10/27/06
WO R2077340,Torus Coating Repair Record Bay 4, 144/160 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 5, 130/130 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 6, 66/66 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 7, 36/36 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 8, 59/61 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 9, 41/47 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 10, 80/80 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 11, 62/71 indications repaired, 10/25/06
WO R2077340,Torus Coating Repair Record Bay 12, 17/24 indications repaired, 10/27/06
WO R2077340,Torus Coating Repair Record Bay 13, 20/41 indications repaired, 10/25/06
WO R2077340,Torus Coating Repair Record Bay 14, 34/34 indications repaired, 10/25/06
WO R2077340,Torus Coating Repair Record Bay 15, 44/44 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 16, 19/19 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 17, 20/27 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 18, 24/24 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 19, 19/19 indications repaired, 10/26/06
WO R2077340,Torus Coating Repair Record Bay 20, 9/16 indications repaired, 10/26/06

Flaw Evaluation

AR 547617 and General Electric INR 01R21 IVVI-06-08, Rev. 0, dated 10/22/2006, Core Shroud Vertical Weld SHD V-09 Two ID Indications
AR A2143996, 11/1/06; Evaluation of pits in (torus) bays 5,15, and 18
AR A2143995, 11/1/06; Evaluate pits in bays 5, 15, and 18 of the torus

Technical Evaluations & Design Evaluations

AR A2152754 E06 Technical Evaluation
AR A2152754 E09 Technical Evaluation
IR 0553792-02; Drywell Structural Integrity Basis From 1R21 Inspections
IR 0553792-03; Torus Structural Integrity Basis From 1R21 Inspections
AR A2152754; 10/25/06; Technical Evaluation for the installation of caulking to the drywell to concrete gap at the 10'3" drywell elevation
ECR OC-06-00879-000; 10/30/06; Drywell Floor/Trough/Drainage Inspection and Repairs
ECR OC-06-00879-001; 11/5/06; Drywell Floor/Trough/Drainage Inspection and Repairs
EC/ECR - GE # Index 9-3, Revision 1, 1/31/03; An ASME Section VIII Evaluation of OC Drywell for Without Sand Case Part 1 Stress Analysis
EC/ECR - GE # Index 9-4, Revision 3, 1/31/03; An ASME Section VIII Evaluation of OC Drywell for Without Sand Case Part 2 Stability Analysis
GE Ltr. Dated 12/11/92; Sandbed Local Thinning and Raising the Fixity Height Analyses (Line Items 1 and 2 in Contract # PC-0391407)
MPR-953, October 1986; GPU Nuclear Corporation, Oyster Creek Nuclear Generating Station Torus Shell Thickness Margin
SE No. 328227-001, Revision 5, 12/3/86; 50.59 Evaluation of Drywell Core Boring And Repair (includes cutting of the trenches)
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TDR - 851, Revision 0, 12/27/88; Assessment of Oyster Creek Drywell Shell

Procedures

ER-AA-335-004, Manual Ultrasonic Measurement of Material Thickness and Interfering Conditions, Rev. 2
GE-PDI-UT-2, PDI Generic Procedure for UT of Austenitic Pipe Welds, Rev. 4
ER-AA-330, Conduct of In-service Inspection Activities, Rev. 5
ER-AA-330-002, In-service Inspection of Section XI Welds and Components, Rev. 5
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ER-AA-335-018, VT Inspections
TQ-AA-122, Revision 3; Qualification and Certification of Nondestructive (NDE) Personnel

Specifications

IS-328-227-004, Revision 13, 9/15/06; Specification for Oyster Creek, Function Requirements for Drywell Containment Vessel Thickness Examinations
SP-1302-52-120, Revision 3; Specification for Inspection and Localized Repair of the Torus and Vent System Coating
OCIS-328227-003, Revision 0; Installation Specification for Repair of Concrete Floor Removed in Drywell for UT Readings

Drawings

GPU Nuclear Dwg. No. 3E-153-02-009, Revision 4, 6/9/94; General Arrangement Reactor Building - Sections C-C, D-D, & E-E
Jersey Central Power & Light Co. Oyster Creek Generating Station Unit #1, Dwg. No. 4059-2, Sheet 2 of 3; Revision 2; 5/5/70
GPU Nuclear Dwg. No. 3E-187-29-001, Revision 0, 1/16/92; Drywell Pressure Vessel UT Test Locations
GPU Nuclear Dwg. No. 3B-153-34-1000, Revision 0, 11/1/00; Reactor Building Elev. 10'3" Repair Of Concrete Floor Removal In Drywell For UT Readings
GE Dwg 4059-1, Sheet 1 of 3, Revision 4, 5/5/70; Oyster Creek Reactor Building First Floor At El 23'6" Sections and Details, Sheet 1
GE Dwg 4059-2, Sheet 2 of 3, Revision 2, 5/5/70; Oyster Creek Reactor Building First Floor At El 23'6" Sections and Details, Sheet 2

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AR-546407	AR-548568	AR-546915	AR-550022
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AR-547092	AR-545422	AR-547397	AR-551897
AR-547245	AR-545251	AR-470325	AR-551910
AR-547617	AR-547025	AR-523259	AR-548459
AR-550305	AR-546693	AR-466683	AR-550149
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AR-548227	AR-547236	AR-550181	
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NRC Information Notice 2004-09, April 27, 2004; Corrosion of Steel Containment and Containment Liner

U.S. Atomic Energy Commission, CO Report No. 219/66-1, 4/15/06; Jersey Central Power & Light Company License No. CPPR-15, Dates of Visit; March 22 and 23, 1966

NUREG 5214

NUREG 13.82

NRC Generic Letter 87-05

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AmerGen Ltr. 2130-06-20414, 10/20/06; AmerGen Responses to Open Items Associated with the NRC Draft Safety Evaluation for the Oyster Creek Generating Station Application for License Renewal (TAC No. MC7624)

AmerGen Ltr. 2130-06-20284, 4/4/06; Commitments Associated with Containment (Drywell and Torus) Condition Monitoring Related to AmerGen Application for Renewed Operating License - Oyster Creek Generating Station (TAC No. MC7624)

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NRC Information Notice 97-10, 3/13/97

GPU Nuclear Ltr. C321-95-2235/5000-95-0088, 9/15/95; Oyster Creek Nuclear Generating Station (OCNGS) Docket No. 50-219, Facility operating License No. DPR-16, Drywell Corrosion Monitoring Program

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NRC Ltr. Dated 12/29/86, Docket No. 50-219; Interim Operation For Cycle 12 Following Corrosion of the Drywell Shell (TAC 64016)

GPU Nuclear Ltr. Dated 5/12/87; Oyster Creek Nuclear Generating Station Docket No. 50-219, Generic Letter 87-05

NRC Inspection Report No. 219/66-5, 12/6/66

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

None

Discussed

None

RUTGERS ENVIRONMENTAL LAW CLINIC

123 Washington Street
Newark, NJ 07102-3094
Phone: (973) 353-5695

Rutgers, The State University of New Jersey
School of Law - Newark
Fax: (973) 353-5537

January 16, 2007

VIA E-MAIL AND US MAIL

The Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee
United States Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Committee Members:

I am writing on behalf of STROC, the citizen's coalition comprising Nuclear Information and Resource Service, Jersey Shore Nuclear Watch, Inc., Grandmothers, Mothers and More for Energy Safety, New Jersey Sierra Club, New Jersey Environmental Federation and New Jersey Public Interest Research Group. Thank you once again for the opportunity I had to present at the last meeting of the Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee ("ACRS") on October 3, 2006 and for the time you are affording to listen to our concerns at the next meeting on January 18, 2007. To avoid an overly detailed presentation at that meeting, this letter provides a brief preview of the main thrust of the material to be presented, raises significant new issues regarding aging management of the corroding torus region of the containment, which is related to the drywell corrosion issues already raised, and answers some questions that were raised by Committee members at the meeting on October 3, 2006.

Key Issues Regarding Drywell Corrosion

In my presentation on Thursday I will deal primarily with the corrosion of the drywell in the sandbed region and will show that AmerGen has failed to establish any margin above code requirements. This failure stems from reliance on overly optimistic modeling, failure to adequately measure the extent of the areas that have suffered from serious corrosion, and failure to take account of the latest results from the October 2006 outage, which indicate that corrosion in the sandbed region may be ongoing. Most glaringly, AmerGen stated in an e-mail to NRC Staff dated April 5, 2006 at 10 (ML060960563) that areas corroded to less than 0.736 inches in thickness "could be contiguous, *provided their total area did not exceed one square foot*" and their average thickness was greater than 0.536 inches. This statement was based on modeling conducted by General Electric ("GE") which showed that a shell with a general uniform thickness of 0.736 inches in the sandbed region, but with a one square foot area that was 0.536 inches thick in each bay, would fail code requirements by around 10%. Even if this predicted

Carter H. Strickland, Jr., Esq.+	Julia L. Huff, Esq.*+	Kathleen J. Shrekgast, Esq.#	Richard Webster,
Acting Director	Staff Attorney	Staff Attorney	Staff Attorney
cstrickland@kinoy.rutgsers.edu	jhuff@kinoy.rutgers.edu	kshrekgast@kinoy.rutgers.edu	rwebster@kinoy

* Admitted in New Jersey Pursuant to 1:21-3(c) + Also admitted in New York # Also admitted in Pennsylv

degree of code failure were acceptable, which we believe it is not, such contiguous areas measuring more than one square foot probably already existed in 1992 and have probably expanded since then. In addition, the most recent study by Sandia Laboratories (ML070120395, "Sandia Drywell Study") shows that the modeling by GE included an erroneous capacity reduction factor leading to underestimation of the necessary thickness in the sandbed region. Sandia Drywell Study at 67, 77. In fact, the uniform thickness required in the sandbed region to meet the code requirements is 0.844 inches, not 0.736 inches. Id. at 79-80. External measurements show that Bays 1, 9, 11 and 13 have large areas of average thickness less than 0.844 inches. Id. at 91-100. In addition, grids of points measured from the interior in Bays 11, 17, and 19 have an average thickness of less than 0.844 inches. Thus, if the applicant's acceptance criteria were adjusted to reflect the mistake in the GE analysis, the shell would not meet the corrected criteria. Its serviceability is therefore in doubt.

The safety of the drywell is brought into further question by two other results from the Sandia Drywell Study that are indirectly related to the sandbed corrosion issue. First, the predicted stresses at the bottom of the sandbed under accident conditions are "extremely large exceeding the assumed allowable even for the case with no degradation." Id. at 59. With degradation, the degree of exceedance increases. Id. Thus, the Study shows that the containment could fail under accident conditions, precisely the situation when it is most needed. Second, the Study shows that the drywell fails to meet the requirement for a safety factor of 2 because bucking could occur in the upper region of the drywell at stresses corresponding to a safety factor of 1.95. Id. at 70-71. While Sandia cautioned against using its model as an absolute prediction, this result shows that AmerGen has failed to establish that the drywell will meet safety requirements throughout any extended licensing period.

Torus Corrosion

The torus corrosion issue largely parallels the drywell corrosion issue. Once more, AmerGen is attempting to age manage a corroding safety-critical component through a combination of visual inspections of a protective coating and occasional UT measurements of identified degraded areas. The narrowness of the margins derived from measurements gives rise to doubts about whether the margin has been established given the uncertainty of the measurements. In addition, even though the claimed margins in this area are even narrower than the sandbed region, the proposed inspection regime appears less rigorous. Furthermore, based on the information available to us, we believe that AmerGen may have already failed to carry out a committed action regarding revising the torus corrosion acceptance criteria.

Taking the potential missed commitment first, on May 1, 2006, AmerGen committed to providing "refined acceptance criteria and thresholds for entering torus corrosion coating defects in the corrective action program for further evaluation . . . prior to the next torus coating inspection, which is also prior to the extended period of operation." Letter from Gallagher to NRC, dated May 1, 2006. NRC staff have confirmed that a torus inspection occurred during the October 2006 outage. Thus, we believe that to meet this commitment AmerGen should have provided the refined criteria prior to the last outage. However, the updated SER, issued in December, failed to contain the refined criteria. Instead, it continued to state that AmerGen would provide the criteria "prior to the next [torus coating] inspection and prior to the period of extended operation." SER at 3-136. In addition, searches of ADAMS have not yielded the criteria. When we asked NRC staff for the refined criteria, they indicated that they did not believe the May 1, 2006 commitment required AmerGen to develop refined criteria for the torus inspection in October 2006. Because we believe the plain meaning of the commitment is that refined criteria had to be developed before October 2006 and, despite diligent efforts, we have been unable to find any refined criteria, we believe AmerGen may have failed to carry out a committed action. We also question how NRC staff can make a final evaluation of the aging management program for the torus when the acceptance criteria, which are a critical part of that program, have not yet been submitted by the applicant.

Moving on to the substance of the torus corrosion issue, the information available indicates that the margins for general corrosion are 0.004 inches to 0.008 inches, depending on the exact location. Letter from Gallagher to NRC dated April 7, 2006 at 29. In addition, individual pits must be less than 0.141 inches or 0.261 inches, depending on the diameter of the pit and spacing between pits. Id. at 30. At the outset, we question whether the accuracy of UT measurements is sufficient to be certain any margin exists and note that no estimate of uncertainty was included in the reporting of the measured thickness of the torus. Id. at 29 In the sandbed region, AmerGen recently found that a single measurement was incorrect by over 0.4 inches, SER at 3-126, and a whole set of results taken in 1996 were recently found to contain systematic error of around 0.02 inches. At this time, AmerGen claims that instrument error for UT measurements in the sandbed is around 0.01 inches. SER at 3-127. Thicknesses in the torus are around half the thickness of the sandbed, but even if the instrument error were 0.005 inches and there were also no danger of systematic error, that would lead to doubt about the existence of the claimed margins in the torus, which in some areas are the same or less than the instrument error.

Turning to the individual results, the deepest pit measured was 0.069 inches in 1992. Letter from Gallagher to NRC dated April 7, 2006 at 31. However, it appears that the local acceptance criteria are based on the nominal thickness of 0.385 inches rather than the measured thickness of 0.343 to 0.345 inches. Id. at 30-31. If this is the case, it is hardly surprising that the local acceptance criteria need to be "refined." It also remains unexplained how around 0.04 inches of general corrosion has already occurred. A consultant employed by AmerGen has estimated that corrosion of exposed steel could occur at up to 0.005 inches per year. Id. at 28-29. Furthermore, the last visual inspection results available to us from 2002 show that "blister count indicated a general increase in the formation of new blisters [in the protective coating] and the occurrence of fractured blisters." Id. at 28. AmerGen's summary fails to indicate how its coatings consultant concluded from these results that no inspection was warranted in 2004. Id. at 29. On the contrary, it appears that even more frequent inspections should have been required. As Dr. Hausler pointed out in his letter raising torus corrosion issues with the staff, blistering of the coating is caused by corrosion occurring below the coating. Letter from Hausler to Paul Gunter, dated July 26, 2006. Therefore, because blistering is becoming more extensive as the coating ages, there is a danger of generalized corrosion at a rate of up to 0.005 inches per year. This means that the claimed margin could be consumed in less than a year. To manage this issue, AmerGen has proposed visual inspection of the torus coating every other refueling outage. E.g. Letter from Gallagher to NRC, dated October 20, 2006. Even if the claimed margins are actually present, which we question, this appears insufficient for two reasons. First, as Dr.

Hausler has pointed out repeatedly corrosion can occur under a coating without being visible and, unlike in the sandbed region, we have found no commitment to take quantitative measurements as a backstop to the visual inspection. Second, the narrow margin and potential corrosion rate seem to indicate that inspection frequency must be increased to less than one year.

Answers to Questions

Finally, at the last meeting I promised to provide you with answers to a few questions. Most simply, the coating testing standards to which Dr. Hausler refers are as follows:

1. National Association of Corrosion Engineers, International, Standard Test Method **TM-00384**: *"Holiday Detection of Internal Tubular Coatings of 250 μm (10 mils) dry Film Thickness"*
2. National Association of Corrosion Engineers, International, Standard Recommended Practice, **RP-0188-90**, *"Discontinuity Testing of Protective Coatings"*
3. National Association of Corrosion Engineers, International, Standard Test Method **TM-0186-94**: *Holiday Detection of Internal Tubular Coatings of 250 to 760 μm (10 to 30 mils) Dry Film Thickness*
4. National Association of Corrosion Engineers, International, Test Method **TM-0183**, *"Evaluation of Internal Plastic Coating for Corrosion Control of Tubular Goods in Aqueous Flowing Environment"*

With regard to Stress Corrosion Cracking, you asked for a citation regarding chloride stress corrosion cracking in carbon steels. The attached memo from Dr. Hausler discusses this issue. Overall, Dr. Hausler believes that this failure mechanism must be considered much more carefully before it can be eliminated as a possibility.

Finally, you asked about the source of the chlorides. Unfortunately, once again this not certain. However, empirical evidence shows that in the worst areas over 0.5 inches of steel has corroded from the drywell in the sandbed region and chlorides were observed in the corrosion products. Because the source of the water has not been totally eliminated, it is prudent to work on the basis that chlorides could be present, unless they are shown to be absent.

Conclusion

We trust you will understand that these matters are of the utmost importance for those who live close to the plant and in the region. Most of the issues raised here concern both current safety and relicensing. They must therefore be addressed urgently. At present, we are puzzled how the NRC staff could conclude that the Oyster Creek Nuclear Power Plant currently meets safety requirements, let alone how the staff could decide that it would continue to meet safety requirements for twenty years beyond its current license. We therefore respectfully request the ACRS not to recommend issuance of the SER until the issues raised orally and in this letter are fully resolved.

Yours sincerely,

Richard Webster

CORRO-CONSULTA

8081 Diane Drive
Rudolf H. Hausler
Kaufman, TX 75142
Tel: 972 962 8287 (office)
rudyhau@msn.com
Fax: 972 932 3947
Tel: 972 824 5871 (mobile)

Memorandum

To: Richard Webster, Esq.
Rutgers University

January 16, 2007

From: Rudolf H. Hausler

Subject: **Oyster Creek Drywell Liner**
The Possibility of Stress Corrosion Cracking

Richard,

The ACRS at its last meeting relative to the safety of the Oyster Creek Dry Well Liner inquired with regards to the possibility of *stress corrosion cracking* in carbon steels. A reference relating in a general way to the subject of stress corrosion cracking can be found in the ASM Metals Handbook, Desk Edition, 1985, Chapter 32, pgs 24 - 26. Special reference is made to low alloy and high strength carbon steels, cross-referenced to temperature and aggressive ions. Carbon steels are only listed in the general overview table of this chapter in connection with caustic and carbonate cracking.

The particular steel of the drywell liner is said to be ASTM A 285 (no grade specified) with up to 0.28% carbon and up to 0.9% Mn. As such A-285 is not classified as a low-alloy carbon steel, even though the Mn content is already fairly high, but is considered to be a quenched and tempered carbon steel.

For stress corrosion to occur there are three simultaneous conditions, which need to be fulfilled: The material has to be susceptible, there has to be stress (at a certain level), and the environment has to contain species, which can induce SCC. This basic three-parameter space is further complicated by the many metallurgical and environmental variables. Hence, such a complex situation makes prediction impossible beyond certain general guidelines which have been established over the years and which are summarized in the referenced paper.

With respect to the specific material of the drywell liner, A-285 is a quenched and tempered steel with hardness levels generally well below where a steel is known to become susceptible to SCC. However, there are no specific requirements for this steel with regards to purity, either chemical or due to inclusions. It is well known that inclusions, such as carbides and/or oxides may constitute stress risers, and if they occur at, or near, the surface, are locations for SCC initiation. Furthermore, uneven temper may also induce local stresses, which can be cause for SCC origination.

Perhaps the locations most susceptible to SCC are the welds, of which there are many and some are certainly located in the areas under consideration with regards to general corrosion attack. Welds constitute complex metallurgical entities and if not properly heat-treated present many internal stresses high enough for the metal to become susceptible to SCC.

It might be argued that stress corrosion cracking of the drywell liner is unlikely because the liner is under compressive load rather than tensile stress. However, it cannot be assumed that the structure is completely symmetrical. Asymmetries, such as have been proposed by Stress Engineering can certainly cause linear stresses. Furthermore, there may be internal stresses due to heat treatment, welding, etc, etc. Corrosion pits have been identified as locations where SCC can start. Additionally we should not forget that the entire structure is subject to vibrations. Hence SCC may be aggravated by fatigue.

While at the concrete/metal boundaries the conditions for carbonate induced SCC are certainly present we also know that chlorides have at various times been identified both in the corrosion products as well as in the water present in the sand bed or the former sandbed area.

Therefore a case can be made that in principle all the conditions for SCC are present, or potentially present. It would therefore be unwise to totally rule out such possibilities based on general arguments. We think that detailed studies and measurements should be made in the most susceptible areas, such as the former sand bed and the areas close to the embedded shell wall.

Dr. Rudolf H. Hausler

Rudolf H. Hausler

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FAX COVER PG.

TO: MIKE JUNG (ACRS)
- 301-415-5589

FROM: JOHN BARTON
PH. 772-287-5577
FX 772 287-5576

SUBJ. OYSTER CREEK DRYWELL
QUESTIONS

PGS SENT TOTAL - ~~2~~ 3

J. B.
11-7-06

MIICK JUNG — ACRS

PLS. ADD FOLLOWING QUESTIONS TO LIST OF QUESTIONS RE. "DRYWELL"

o SINCE WATER COLLECTED FROM THE DRYWELL SAND BED REGION DRAINS SHOULD BE SAMPLED PRIOR TO DISCARDING THE CONTENTS OF THE COLLECTION CONTAINERS — "DID THE ANALYSIS OF THE CONTAINERS THAT WERE DISCARDED DURING THE RECENT NRC INSPECTION SUGGEST THAT THE LEAKAGE IS ANYTHING OTHER THAN WATER FROM THE REACTOR CAVITY REGION DURING REFUELING FLOOD UP?"

o IT WAS STATED BY THE APPLICANT AT THE ACRS SUBCOMMITTEE MEETING ON OCTOBER 3, 2006 THAT THE COMMITTMENT TO SEAL THE REACTOR CAVITY REGION WITH STRIPPABLE COATING WAS NOT CARRIED OUT DURING TWO REFUEL OUTAGES BECAUSE IT WAS ASSUMED AT THAT TIME THAT THE PLANT WAS TO BE DECOMMISSIONED. (I BELIEVE THIS TO BE BETWEEN 1998-2000).

o CONT'D

IS IT POSSIBLE THAT THE CONTENTS OF THE COLLECTION BOTTLES WAS ≥ 8 YRS. OLD?

IS IT POSSIBLE THAT LEAKAGE IS OCCURRING EVEN THOUGH YOU ARE NOW - > 2000, COATING THE CAVITY REGION DURING REFUEL OUTAGES? WHERE COULD IT BE COMING FROM??

Oyster Creek Generating Station

License Renewal – ACRS Review

Reference Material from January 18, 2007 ACRS Subcommittee Meeting

AmerGen
An Exelon Company

AmerGen℠
An Exelon Company

Sand Bed Pictures
1992

AmerGen[SM]

An Exelon Company

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

Sand Bed Region 1992

AmerGen
An Exelon Company

Drywell
Shell

Corrosion product on drywell vessel

Sand Bed Region 1992

AmerGen
An Exelon Company

Drywell Shell

As found condition of floor bed

AmerGen
An Exelon Company

Sand Bed Region 1992

Bay 7 As found - Sand Bed Floor

AmerGen[SM]
An Exelon Company

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

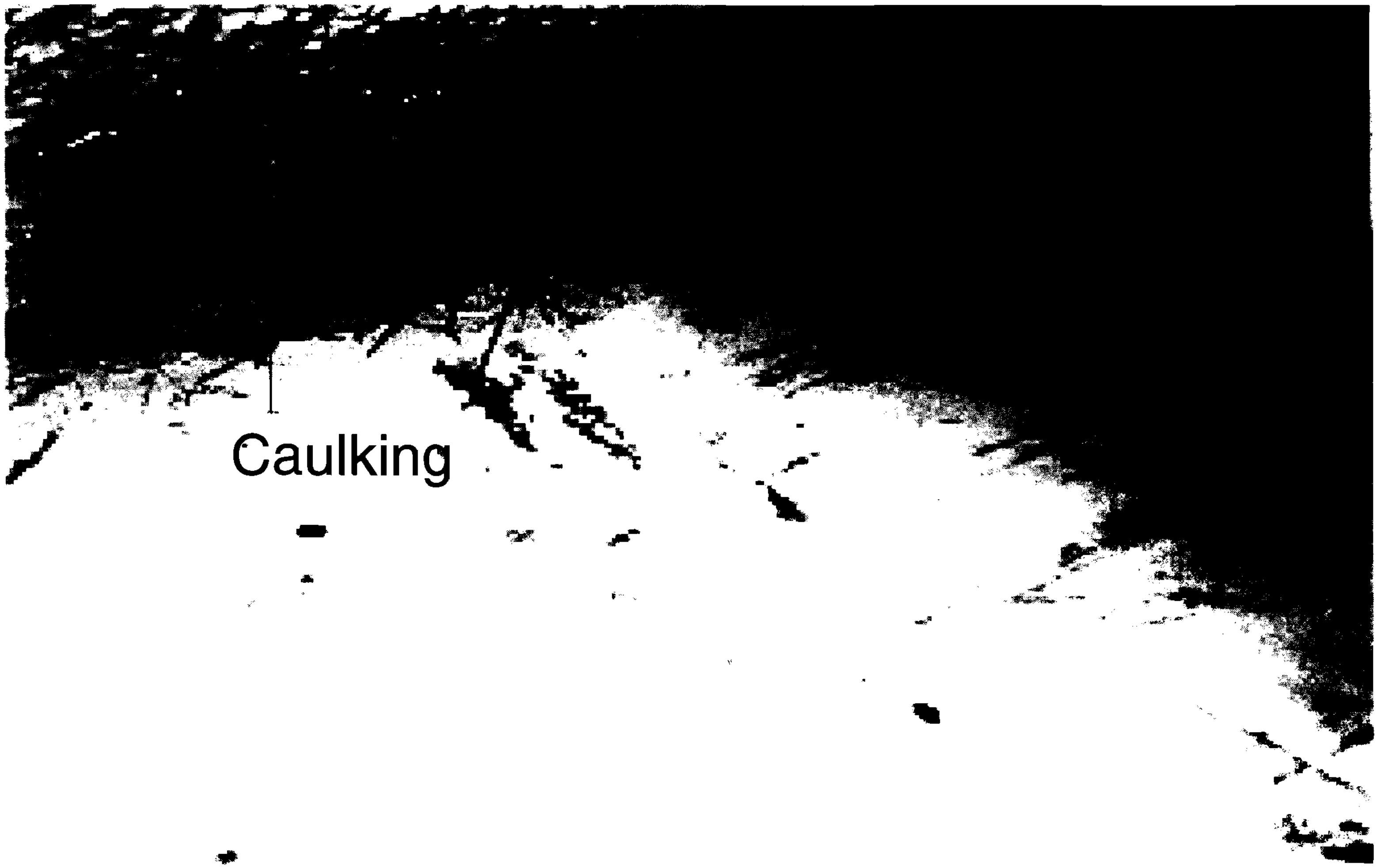
AmerGen℠
An Exelon Company

Sand Bed Region 1992

Bay 5 before shell coating

Sand Bed Region 1992

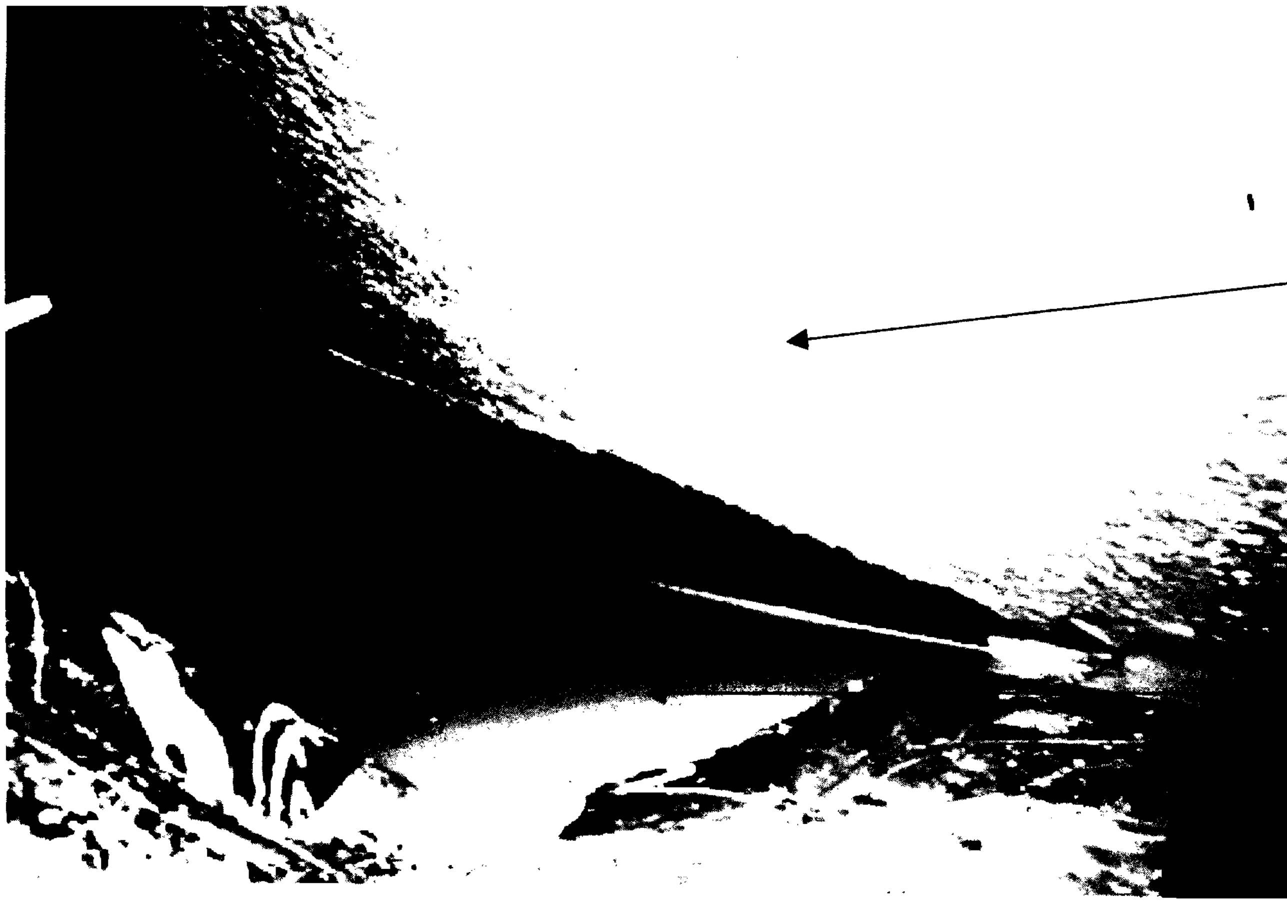
AmerGen
An Exelon Company



Close up of caulking

Sand Bed Region 1992

AmerGen
An Exelon Company



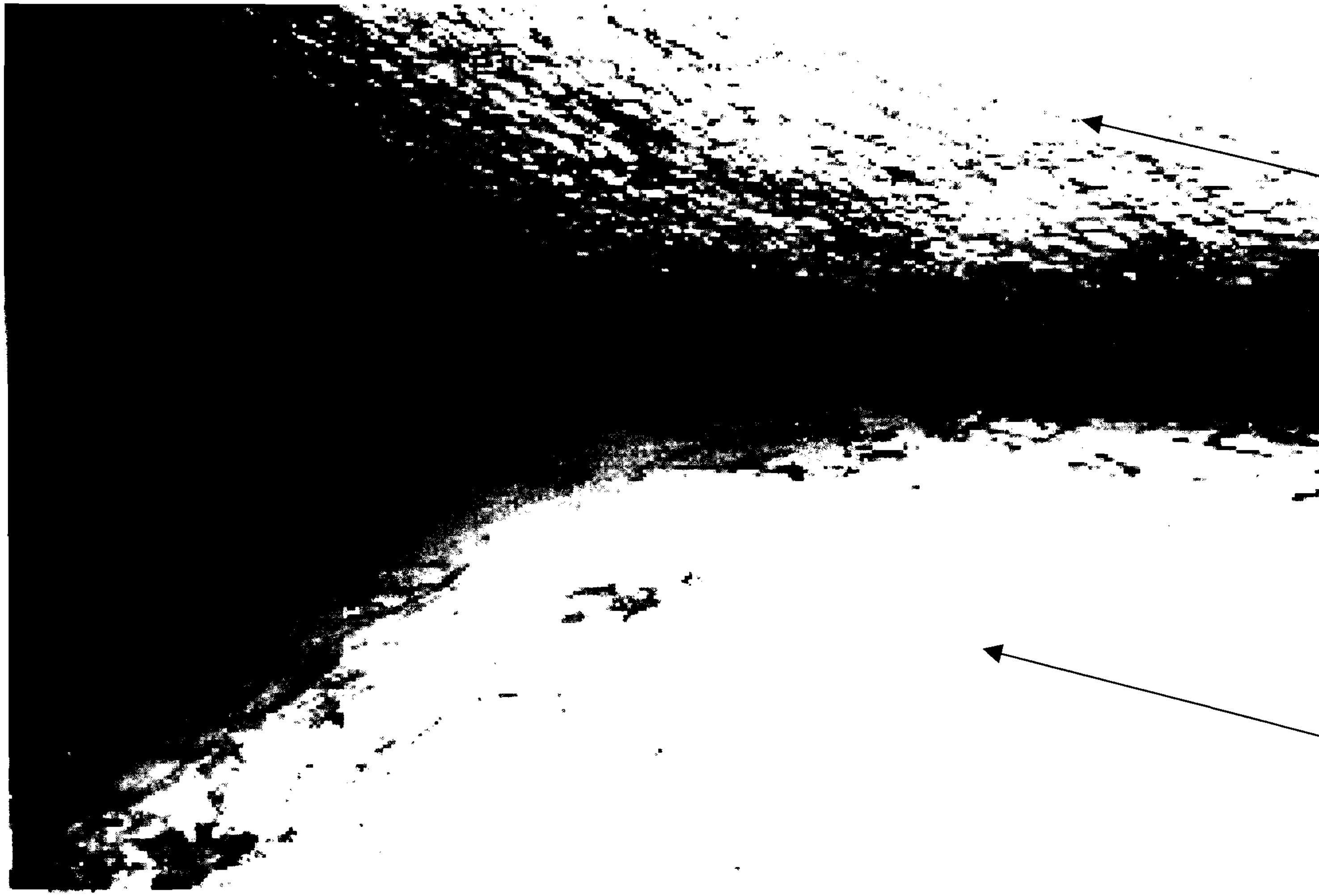
Shell with primer partially applied

Floor

Shell and floor undergoing coating and repairs

AmerGen
An Exelon Company

Sand Bed Region 1992



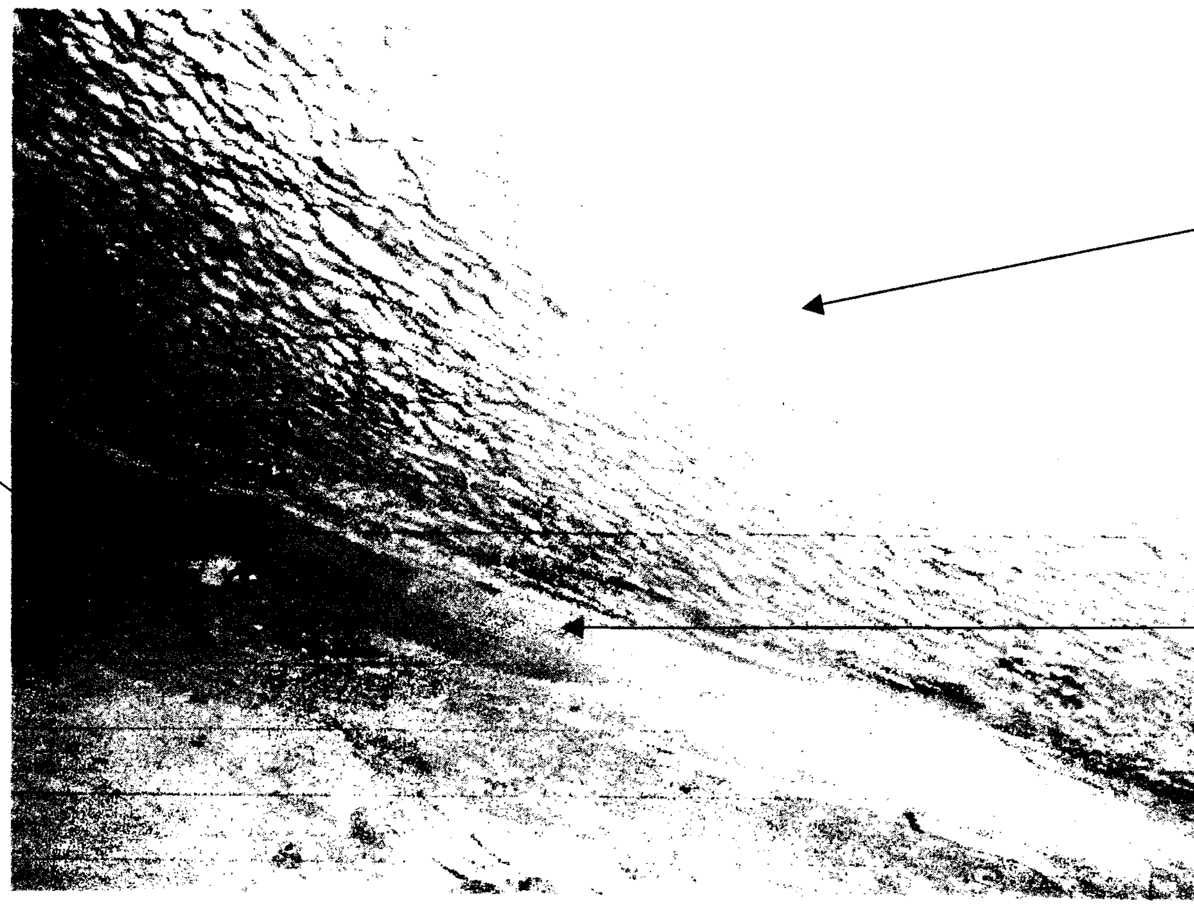
Finished floor, vessel with two top coats – caulking material applied

AmerGen[SM]
An Exelon Company

Sand Bed Pictures 2006

Sand Bed Region 2006

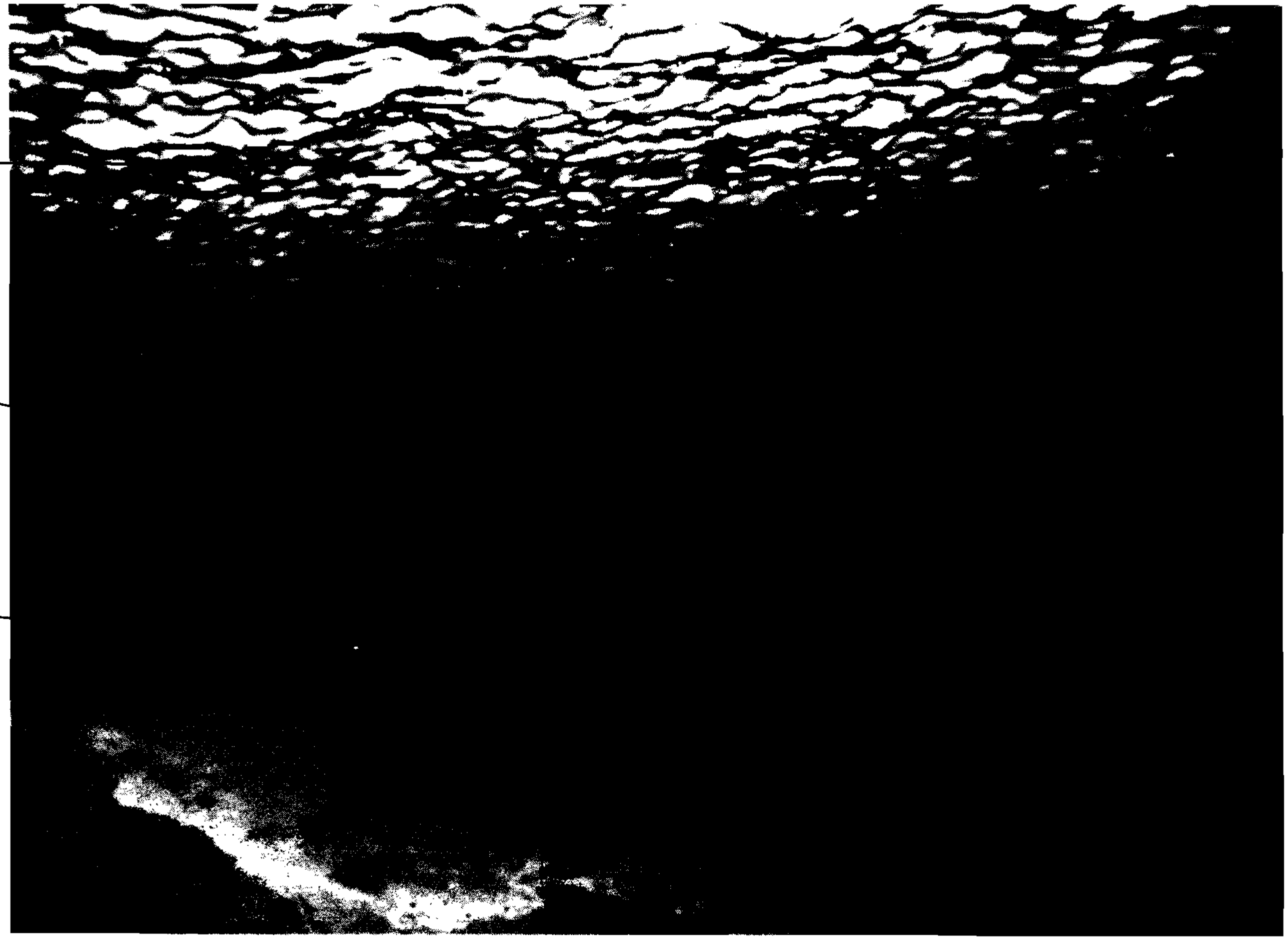
AmerGen
An Exelon Company



Bay 1 caulking

Sand Bed Region 2006

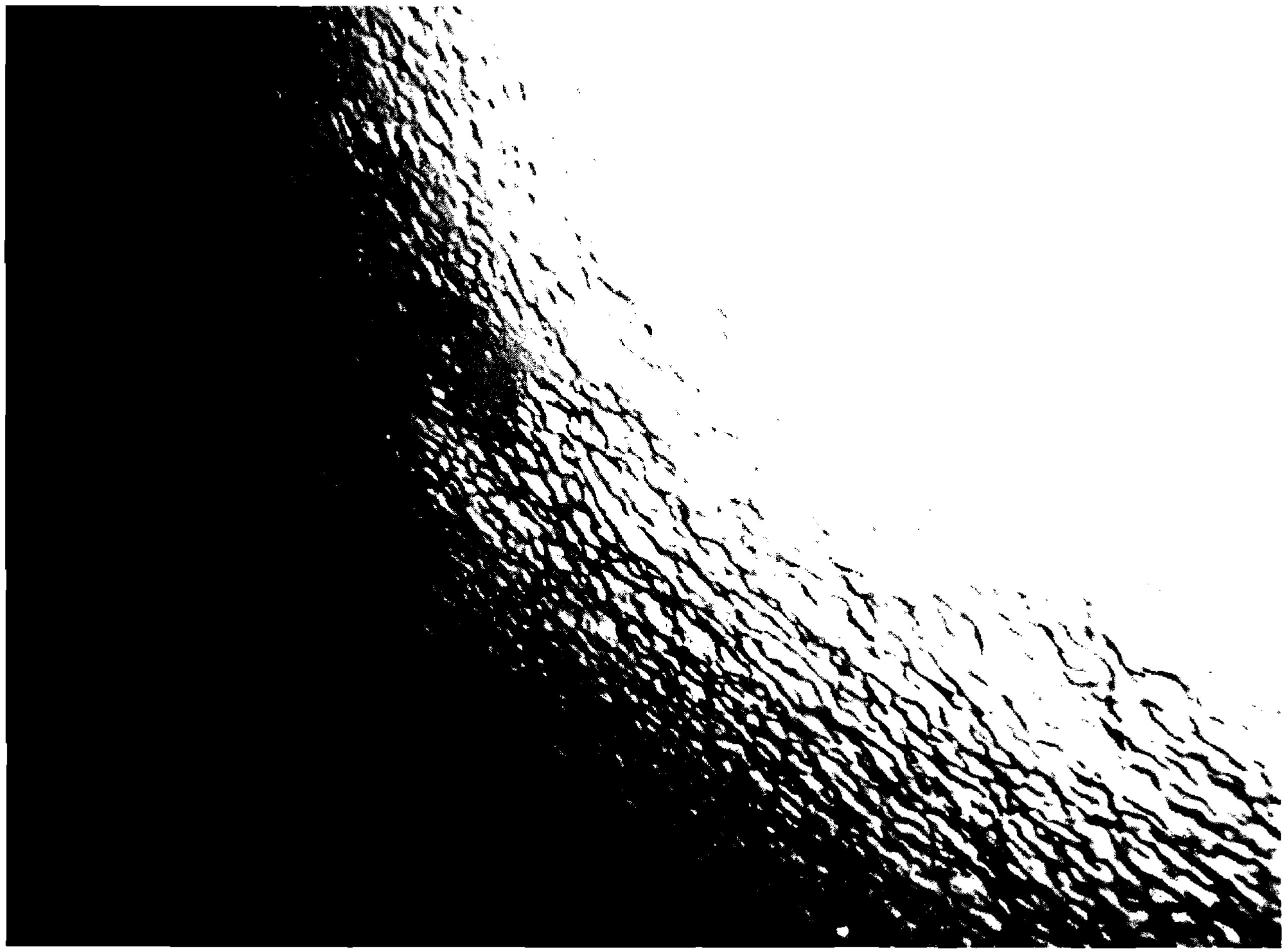
AmerGen
An Exelon Company



Bay 3

Sand Bed Region 2006

AmerGen
An Exelon Company



Bay 3 Shell

Sand Bed Region 2006

AmerGen
An Exelon Company

Shell – External UT inspection location

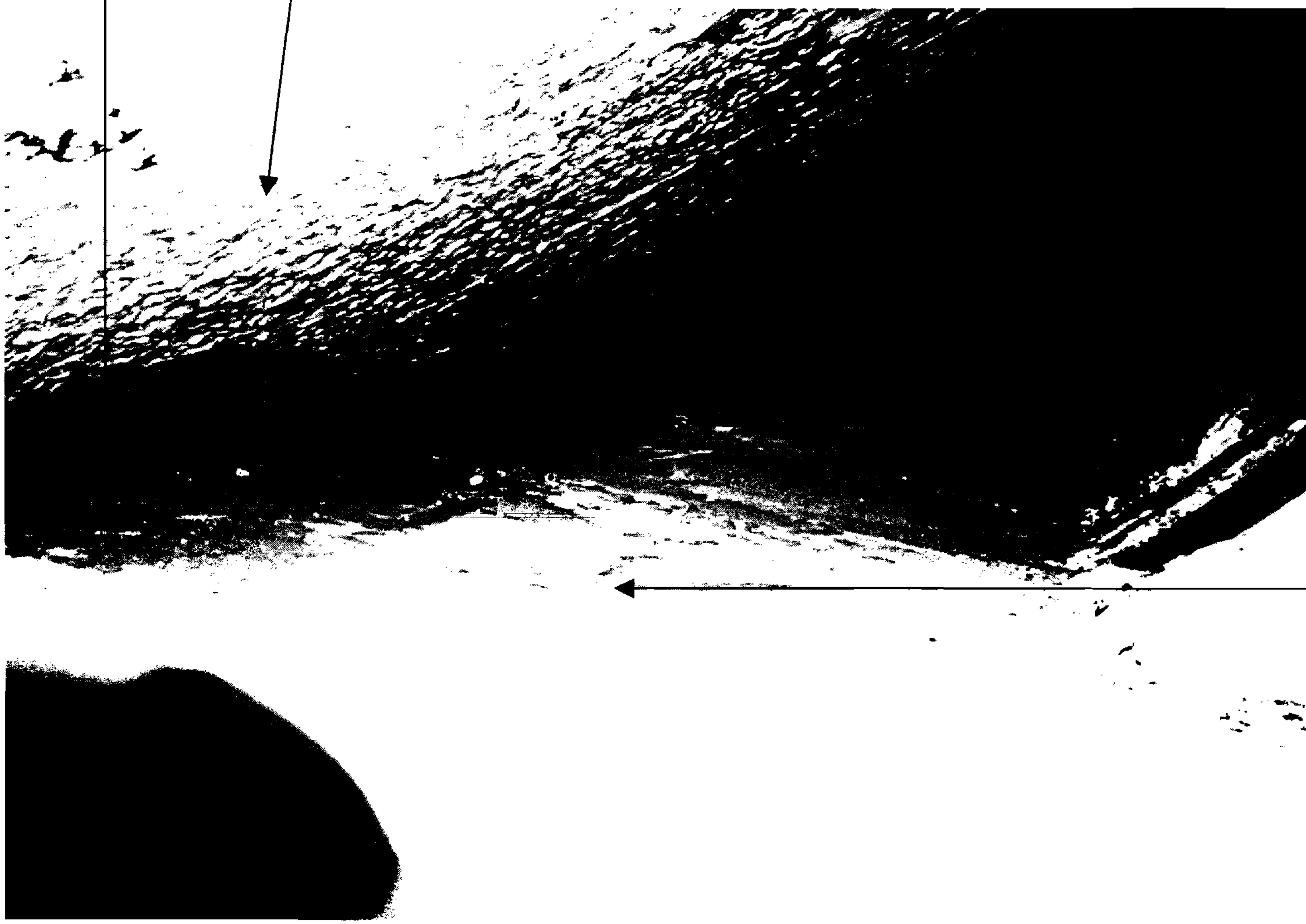
(Surface prep'd in 1992 before coating)

Floor

Bay 5 – Drywell shell and sand bed floor

Sand Bed Region 2006

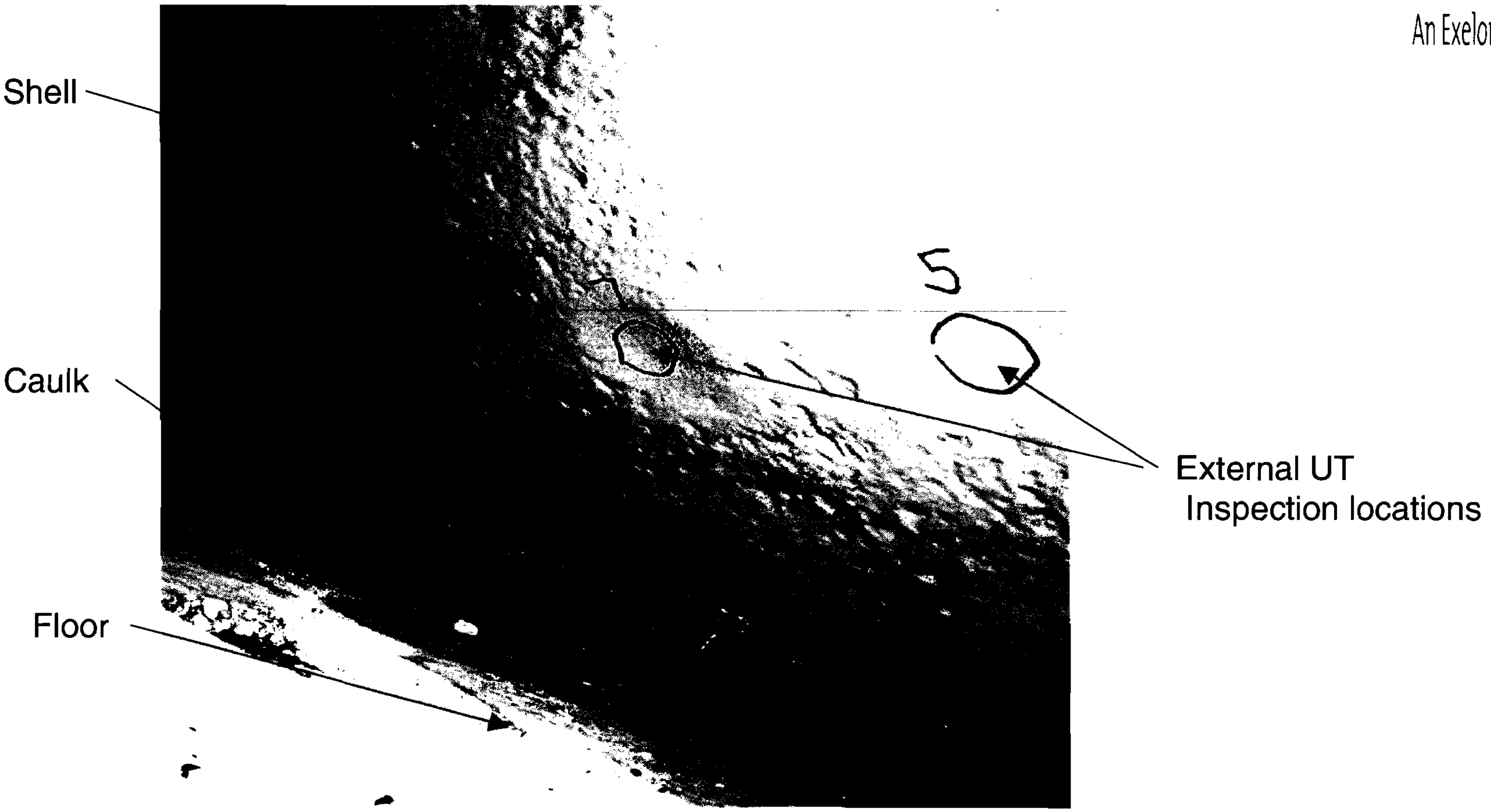
AmerGen
An Exelon Company



Bay 5 – Drywell shell, floor, and caulking

Sand Bed Region 2006

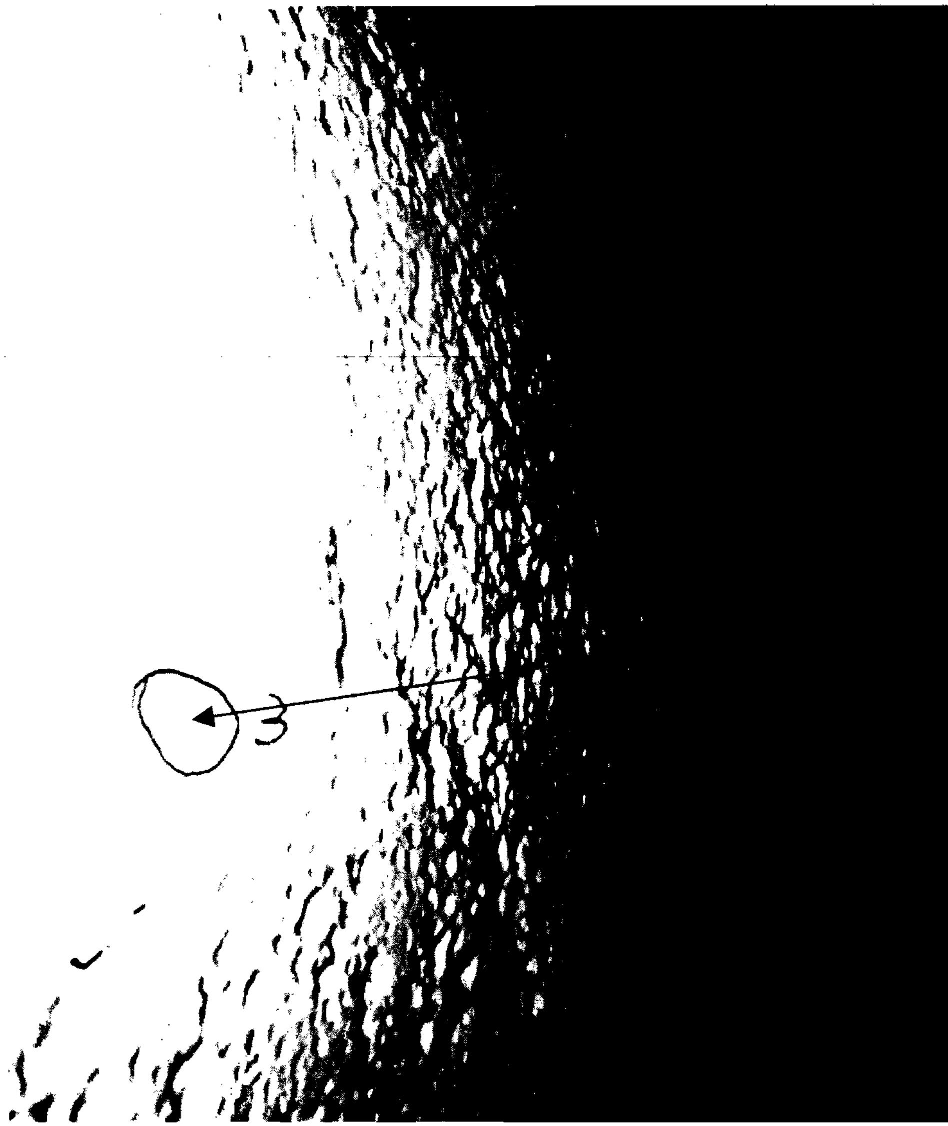
AmerGen
An Exelon Company



Bay 7 – Drywell shell, caulking, sand bed floor

Sand Bed Region 2006

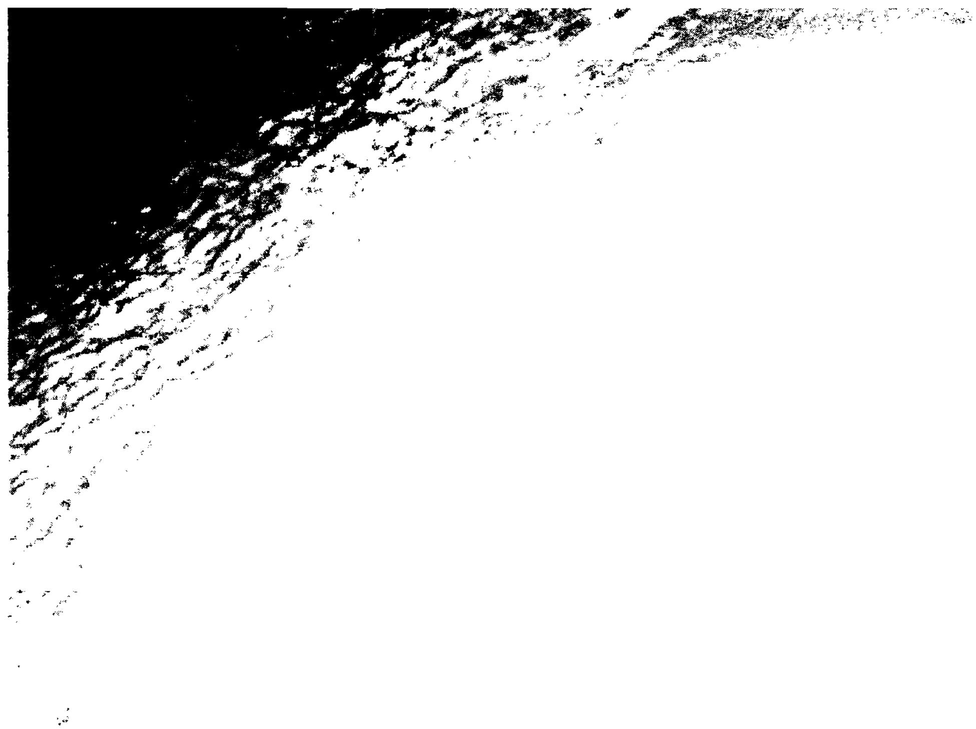
AmerGen
An Exelon Company



Bay 7 – External UT inspection location

Sand Bed Region 2006

AmerGen
An Exelon Company

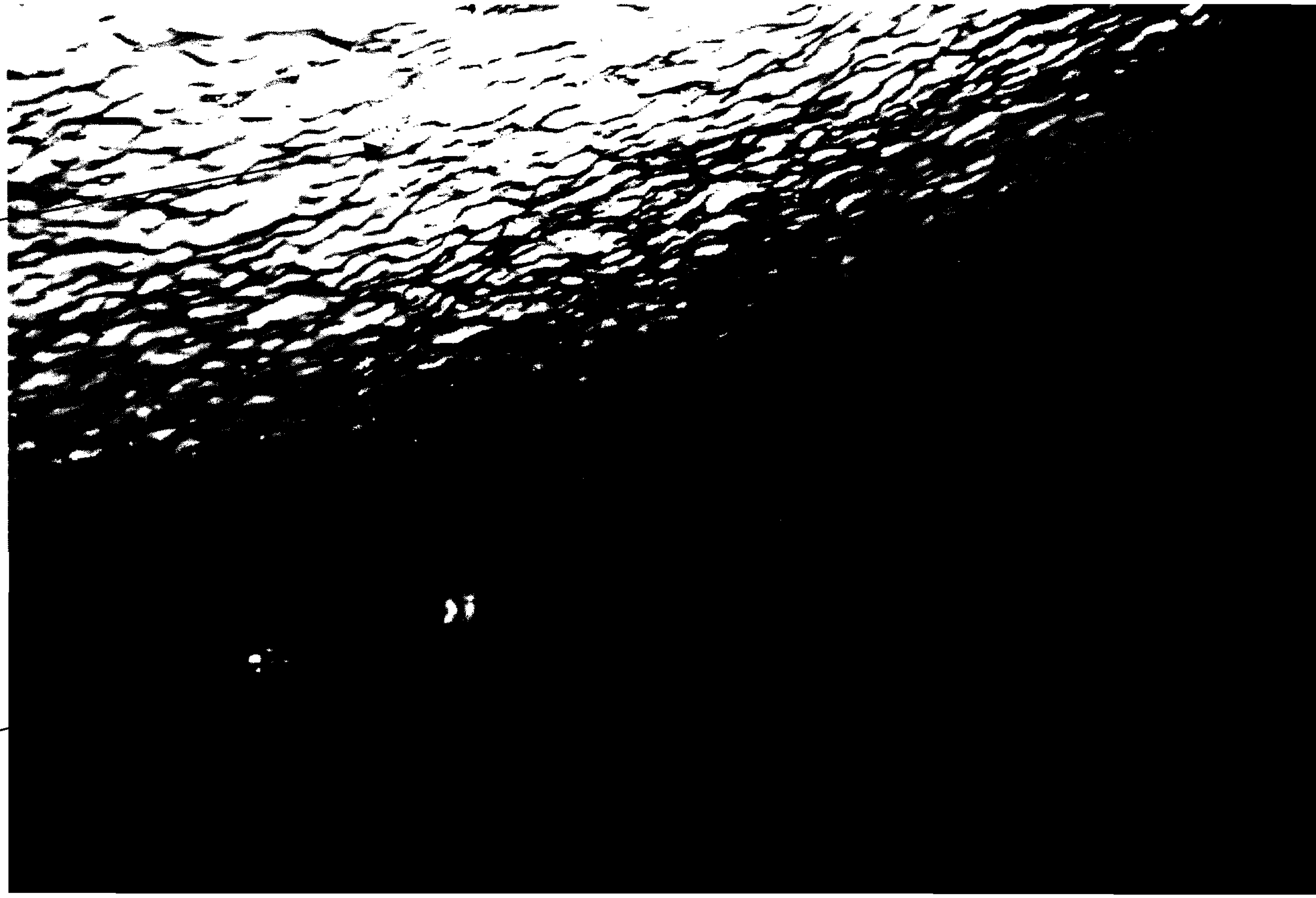


Bay 9 left side

Drywell Shell Bay 9

Sand Bed Region 2006

AmerGen
An Exelon Company



Drywell shell

Caulk seal

Sand bed floor

Bay 11

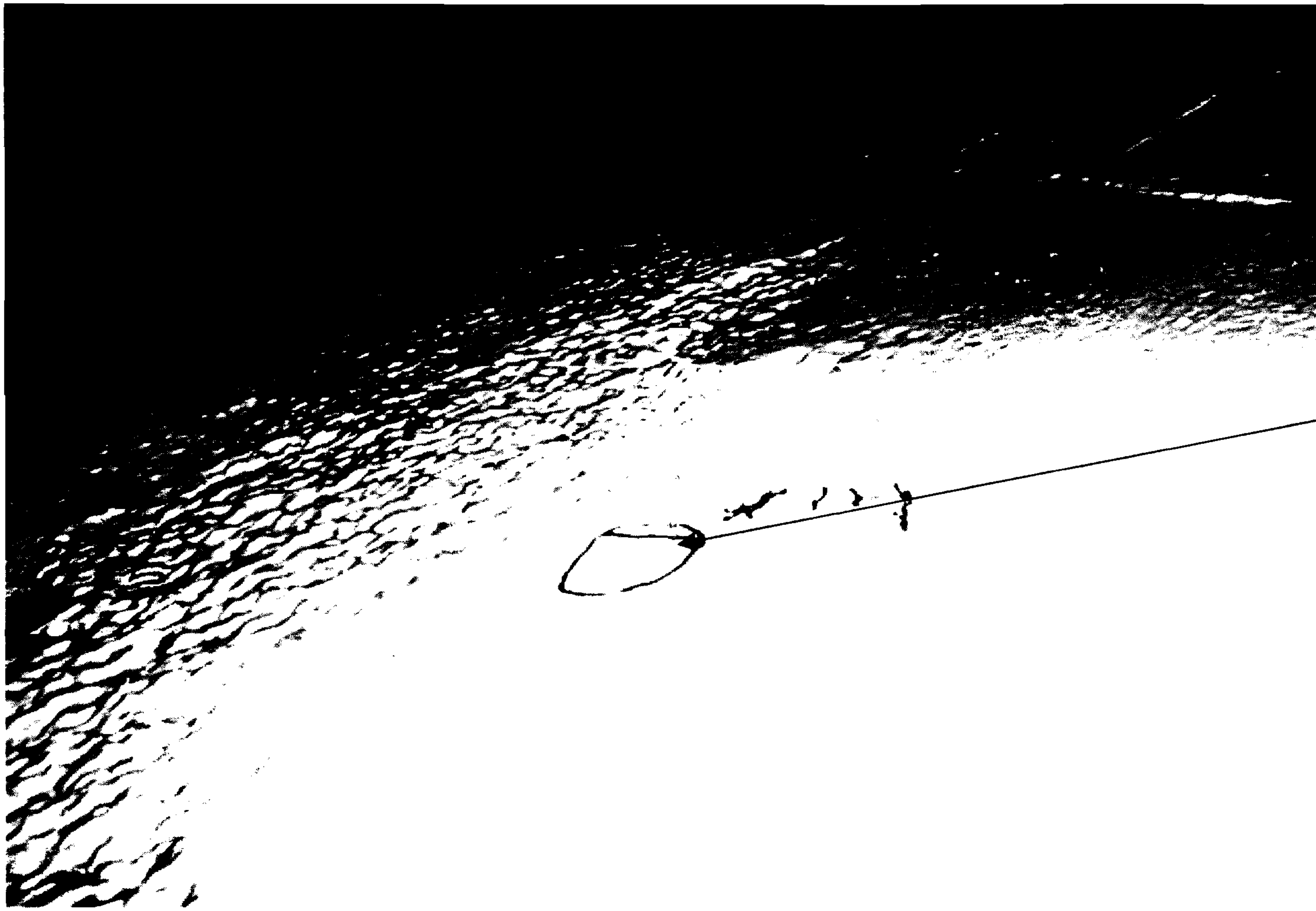
AmerGen
An Exelon Company

Sand Bed Region 2006

Bay 13 – Close-up of shell and caulk seal

Sand Bed Region 2006

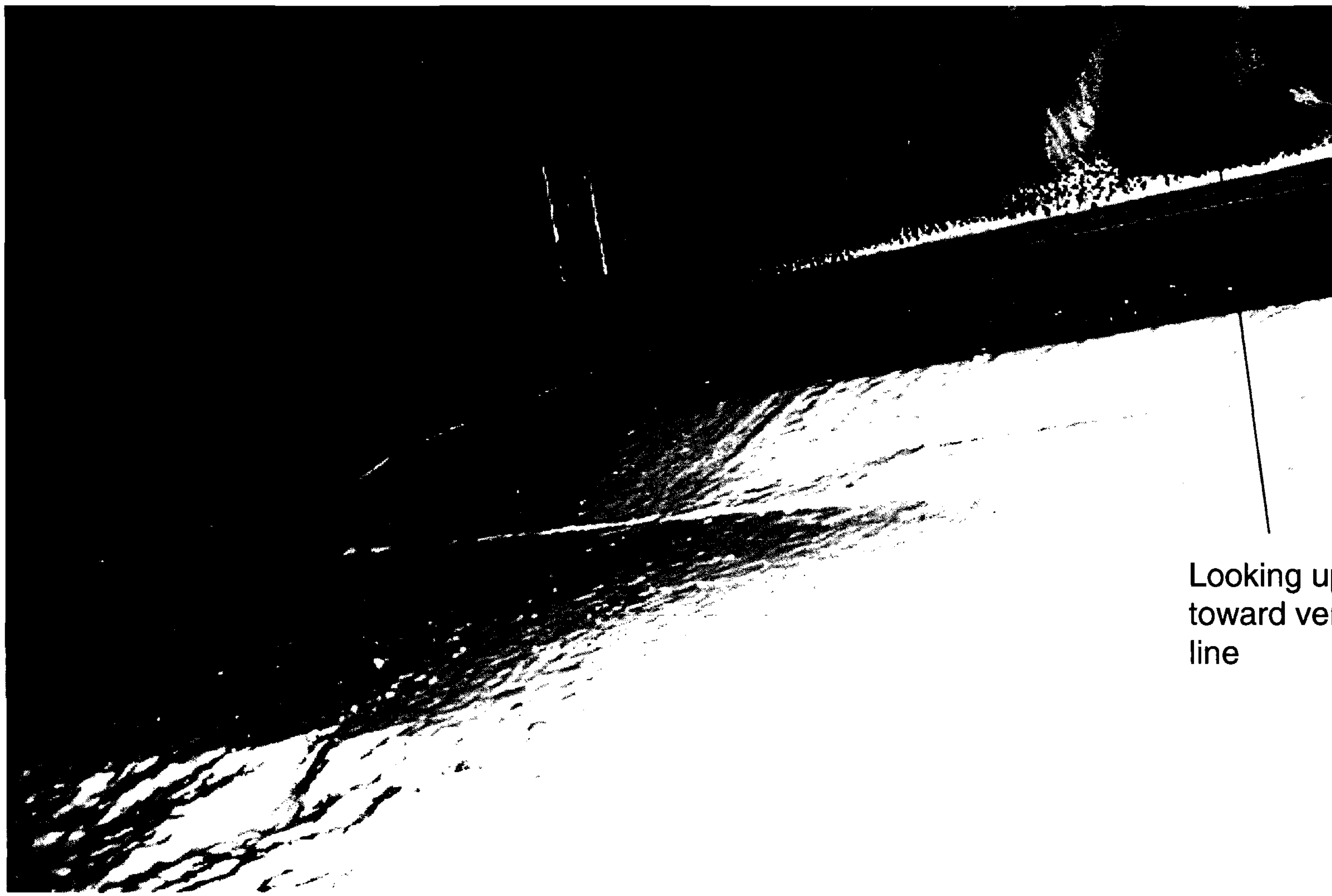
AmerGen
An Exelon Company



Bay 13 Drywell shell

Sand Bed Region 2006

AmerGen
An Exelon Company

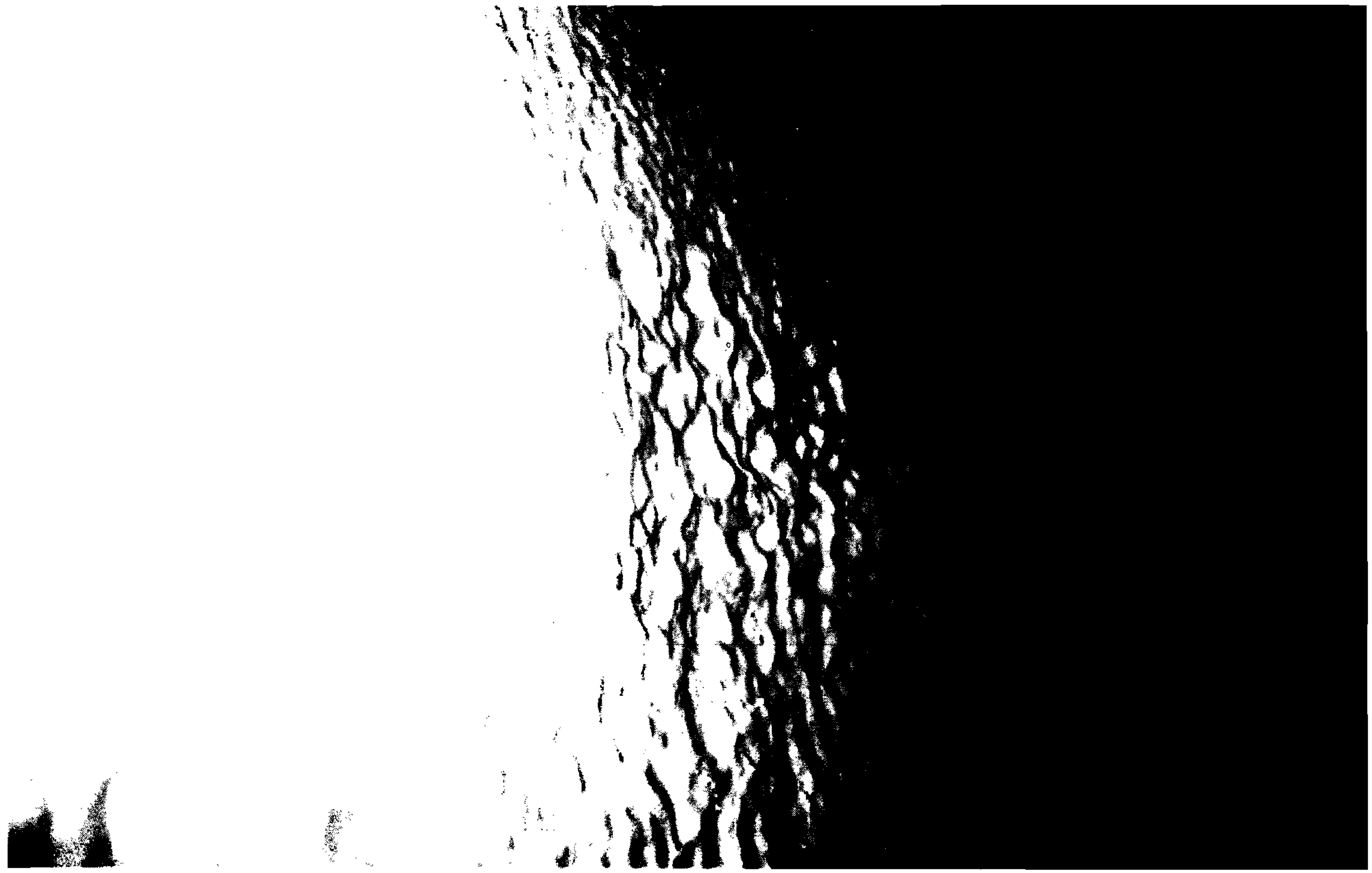


Looking up toward vent line

Bay 13 Drywell shell

Sand Bed Region 2006

AmerGen
An Exelon Company



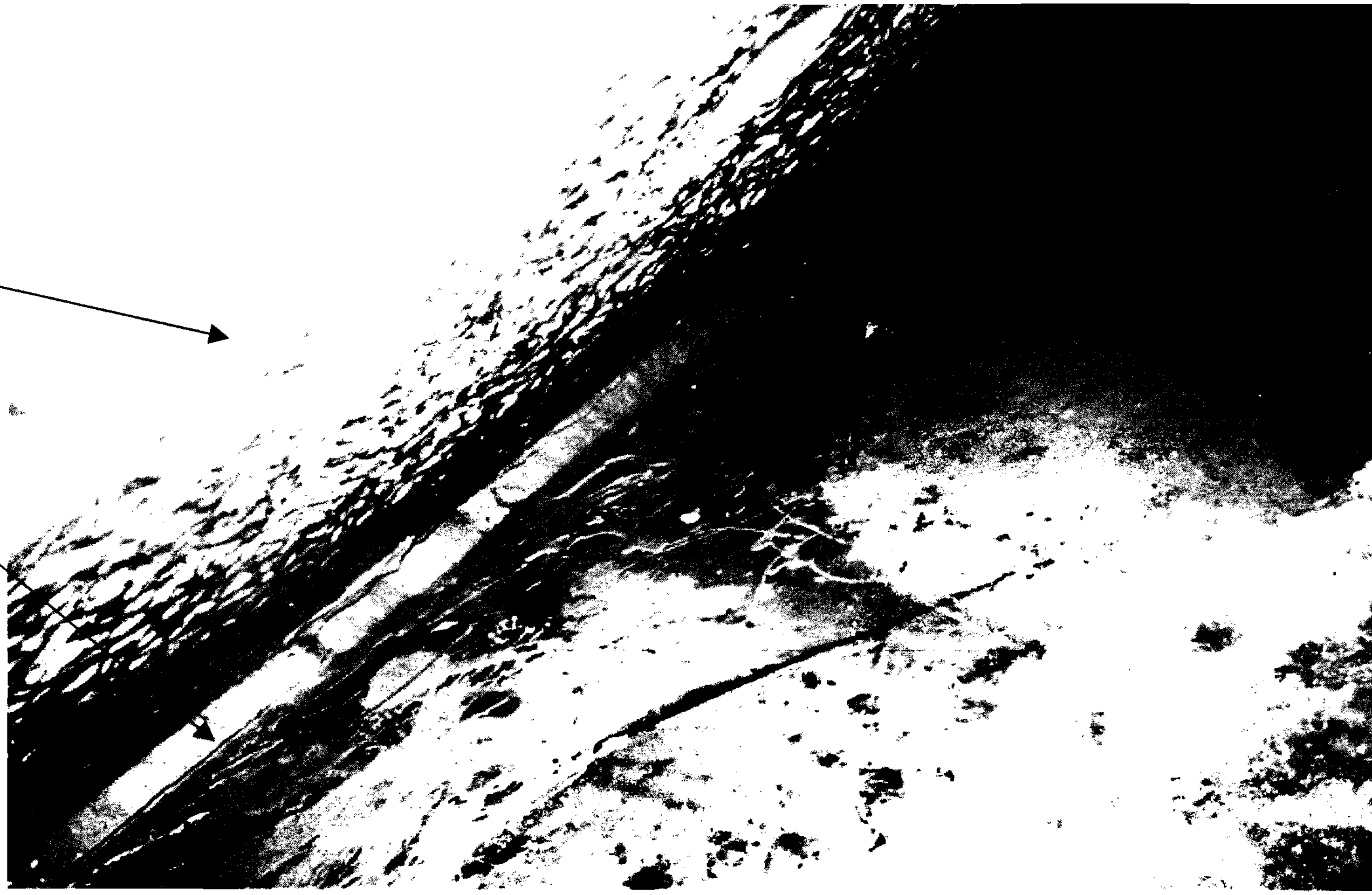
Bay 15 – Drywell shell

Sand Bed Region 2006

AmerGen
An Exelon Company

Shell

Caulk

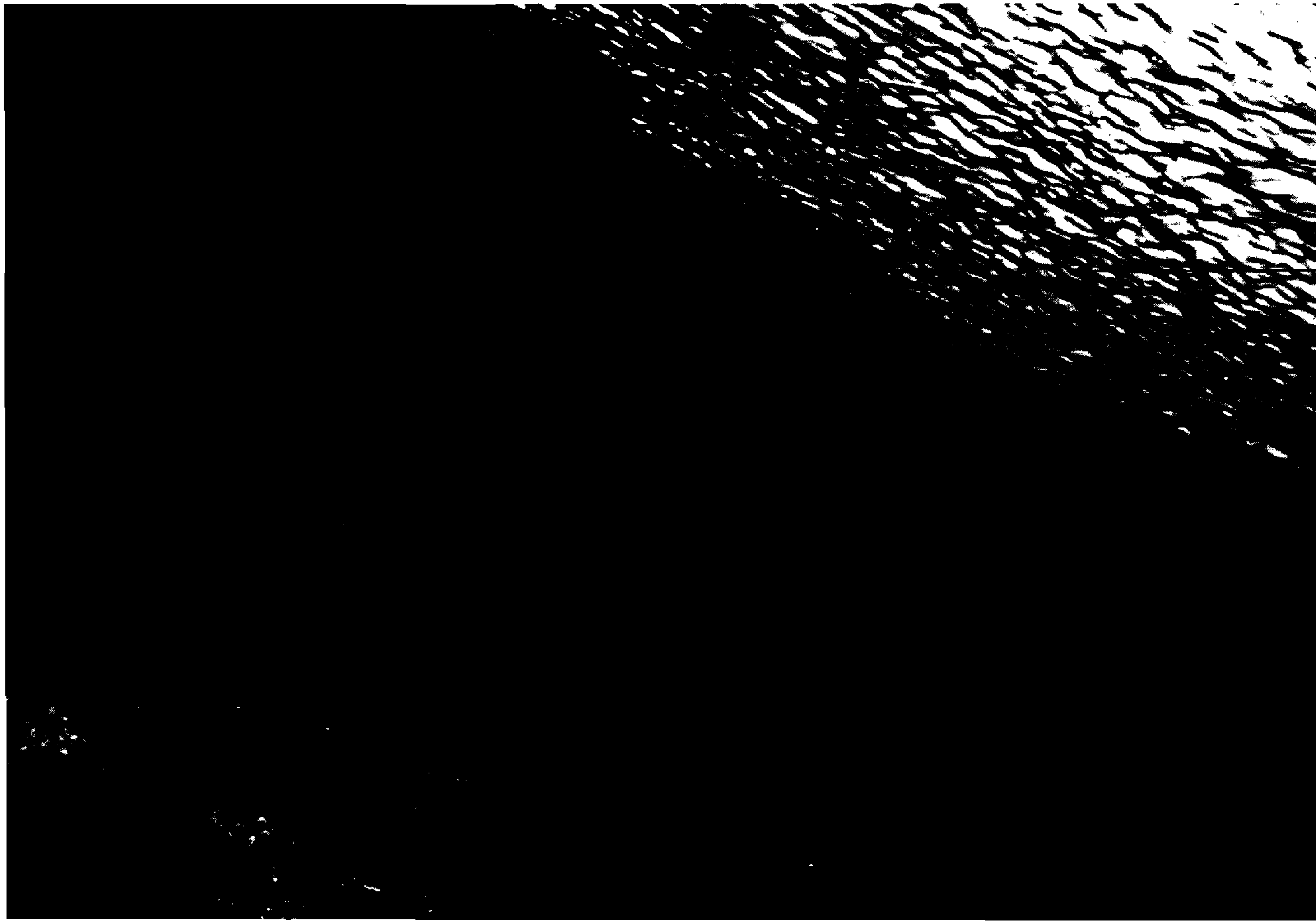


Floor

Bay 15

Sand Bed Region 2006

AmerGen
An Exelon Company

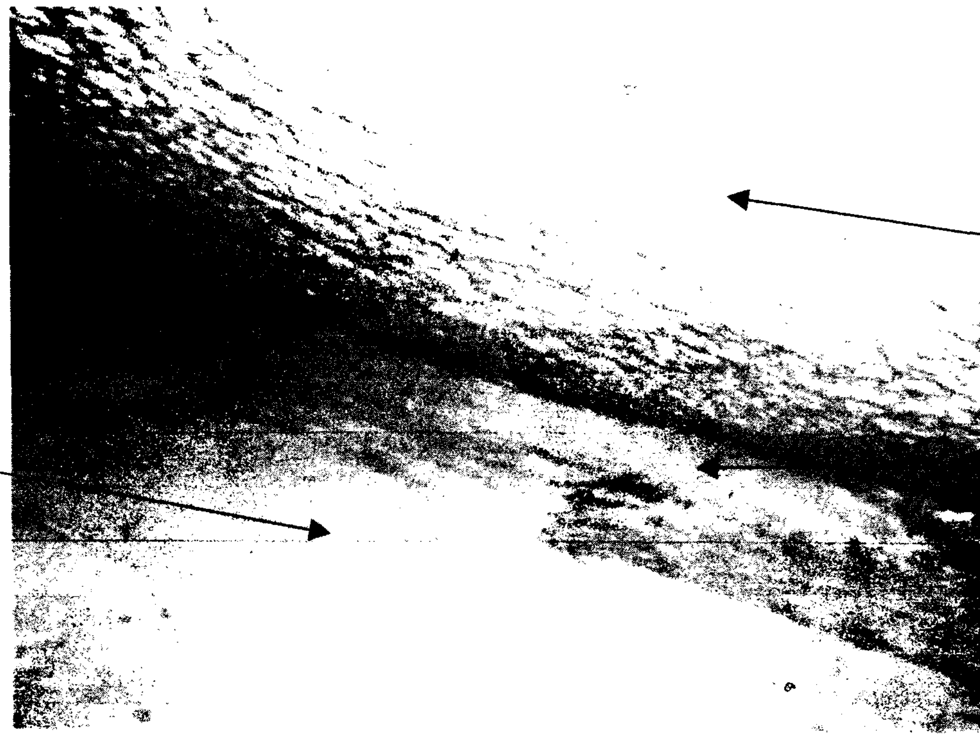


Bay 17 Sand Bed Area

AmerGen[SM]

An Exelon Company

Sand Bed Region 2006

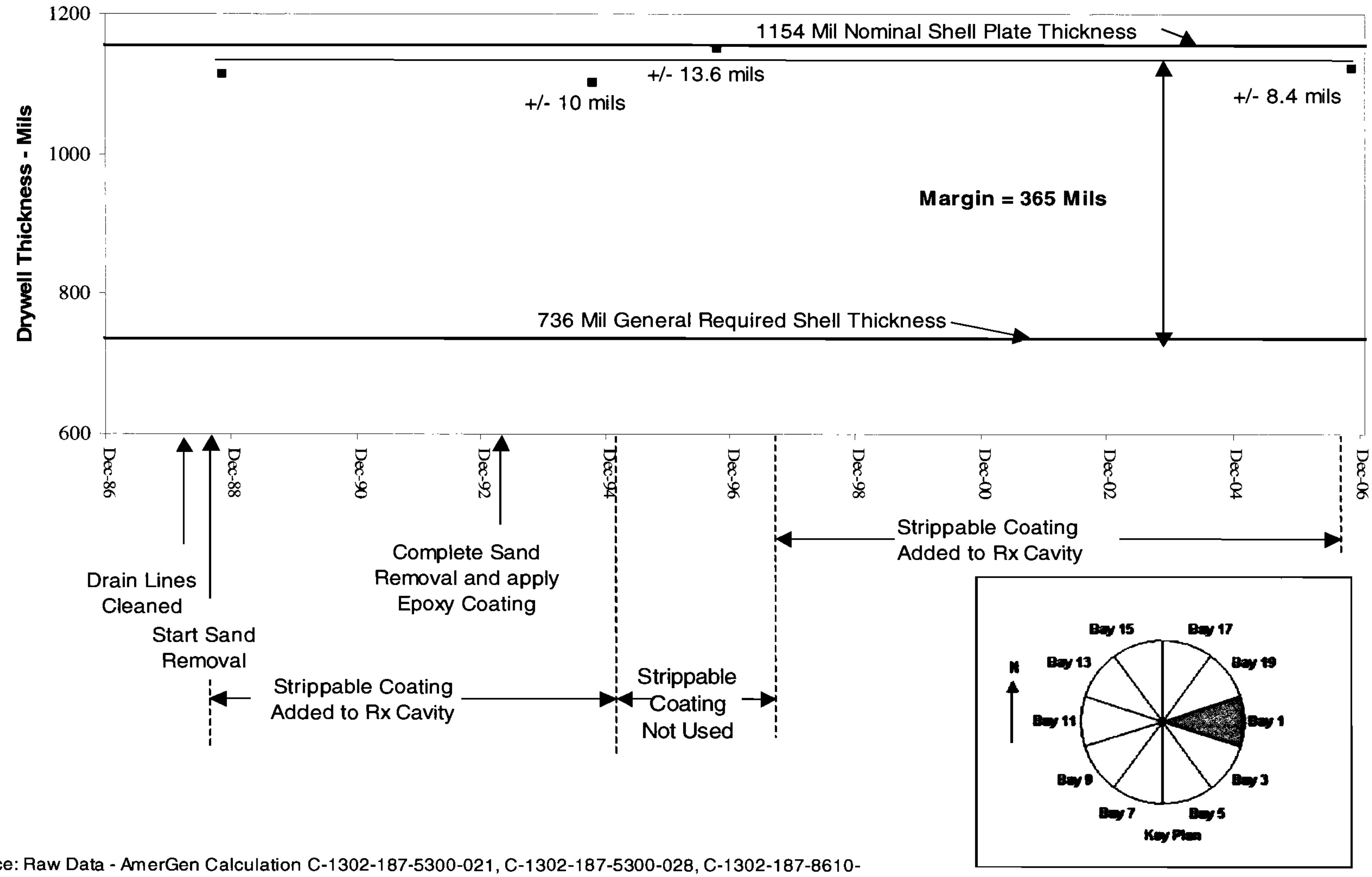


Bay 19 caulking

Drywell Shell Bay 19

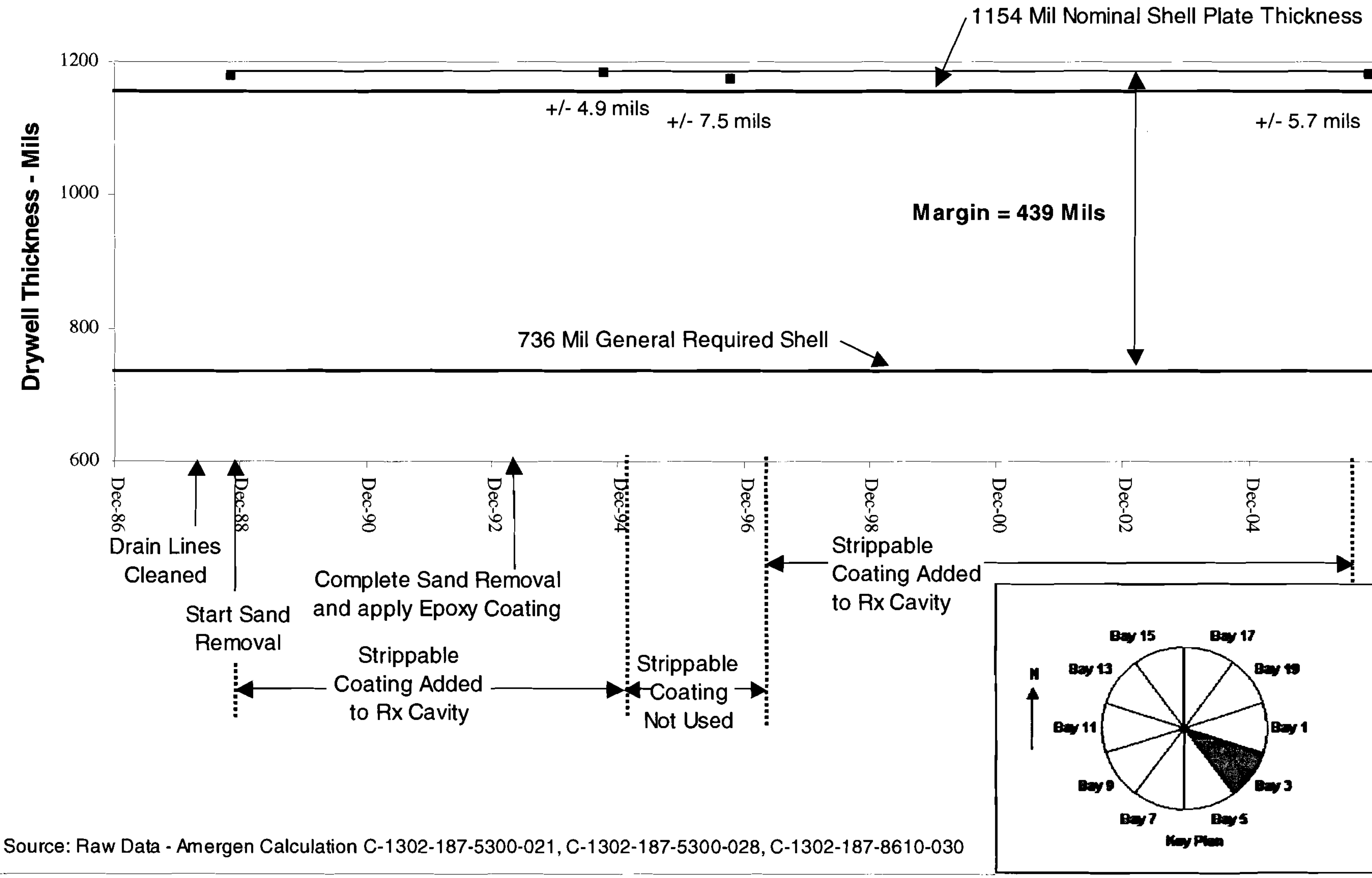
Sand Bed Trend

Figure 1. Sandbed Bay # 1D



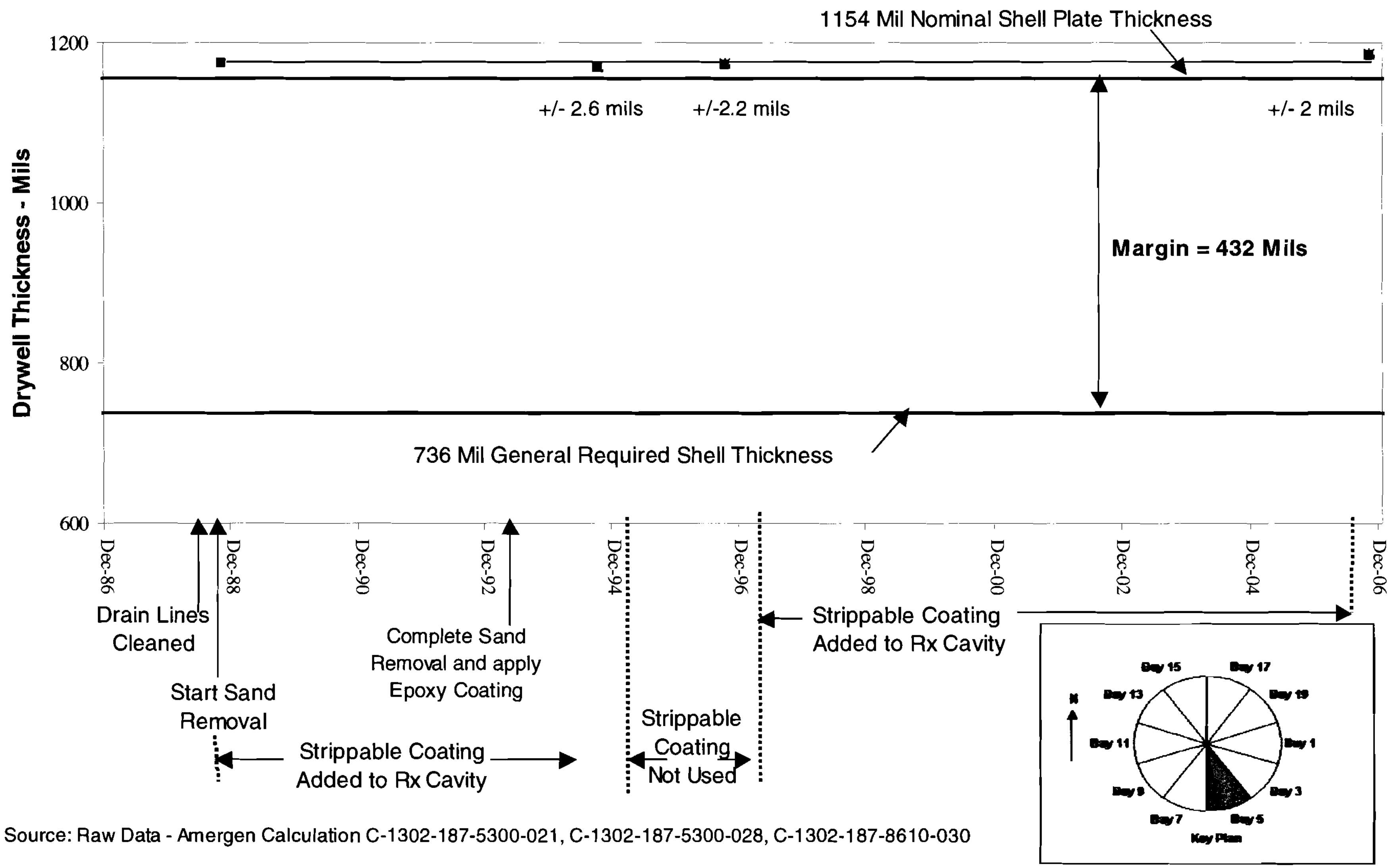
Source: Raw Data - AmerGen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-

Figure 2. Sandbed Bay #3D



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 3. Sandbed Bay # 5D



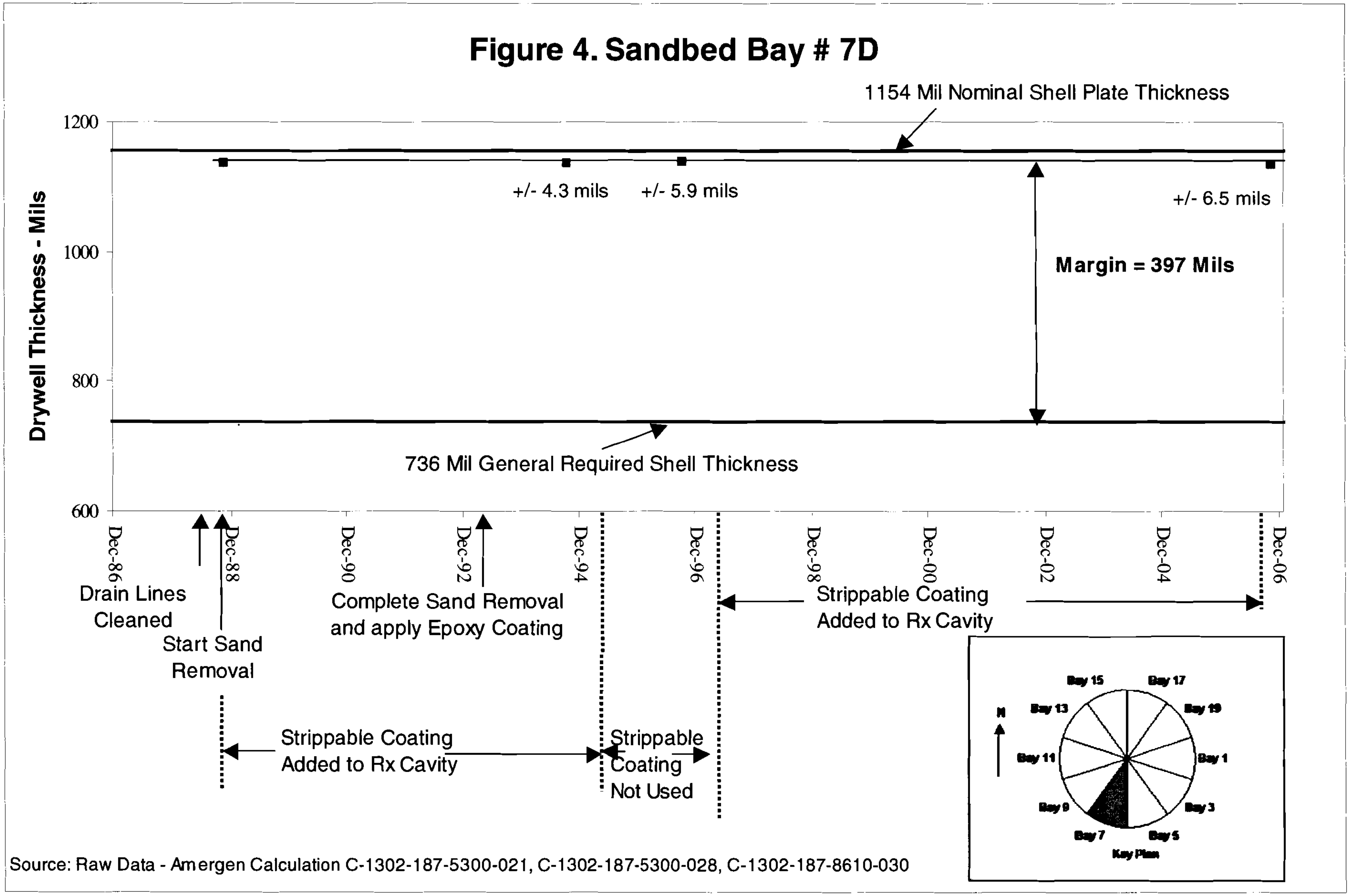
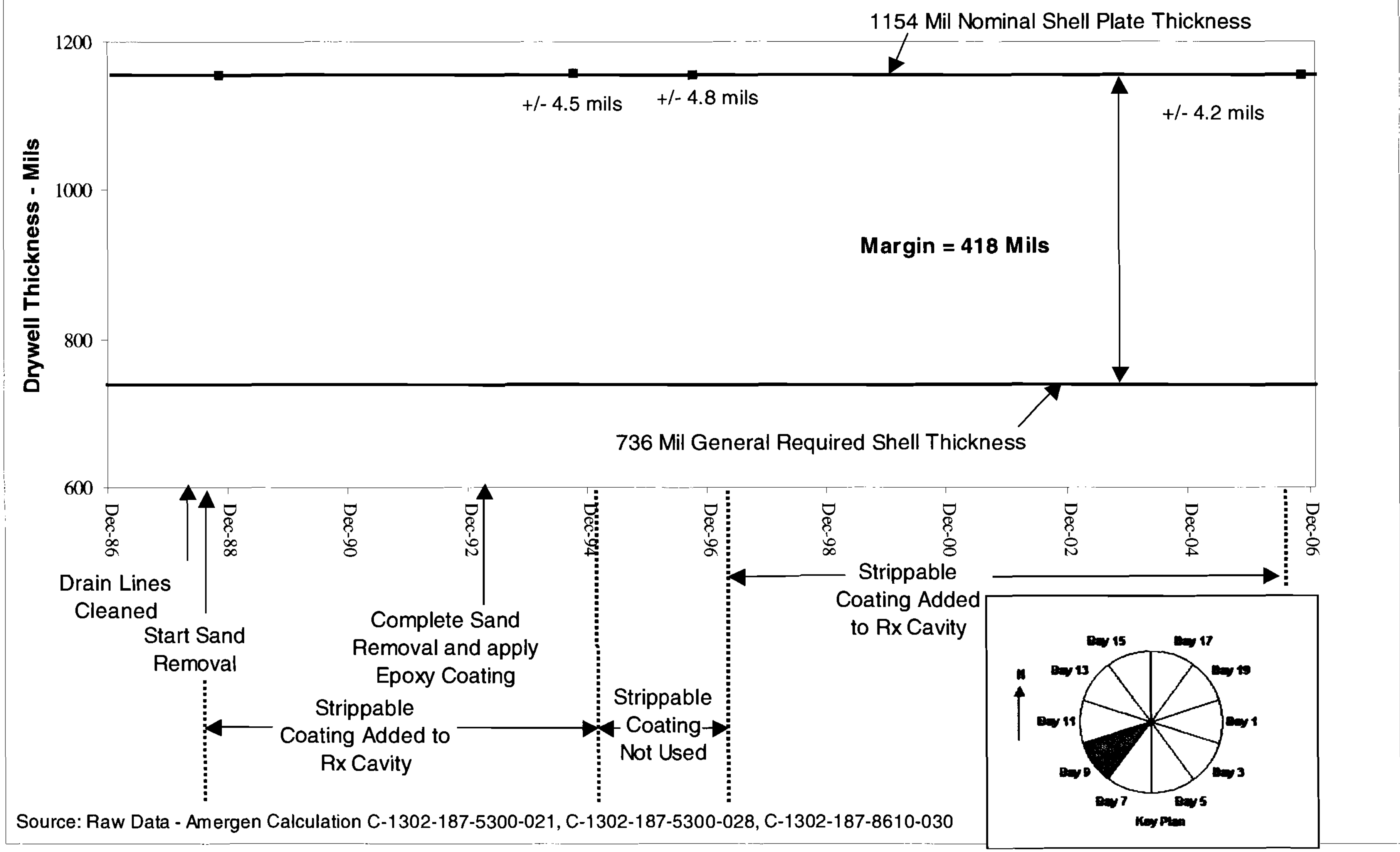


Figure 4. Sandbed Bay # 7D
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
+/- 4.3 mils
+/- 5.9 mils
+/- 6.5 mils
Margin = 397 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
Drain Lines Cleaned
Start Sand Removal
Complete Sand Removal and apply Epoxy Coating
Strippable Coating Added to Rx Cavity
Strippable Coating Added to Rx Cavity
Strippable Coating Not Used
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 5. Sandbed Bay # 9A



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

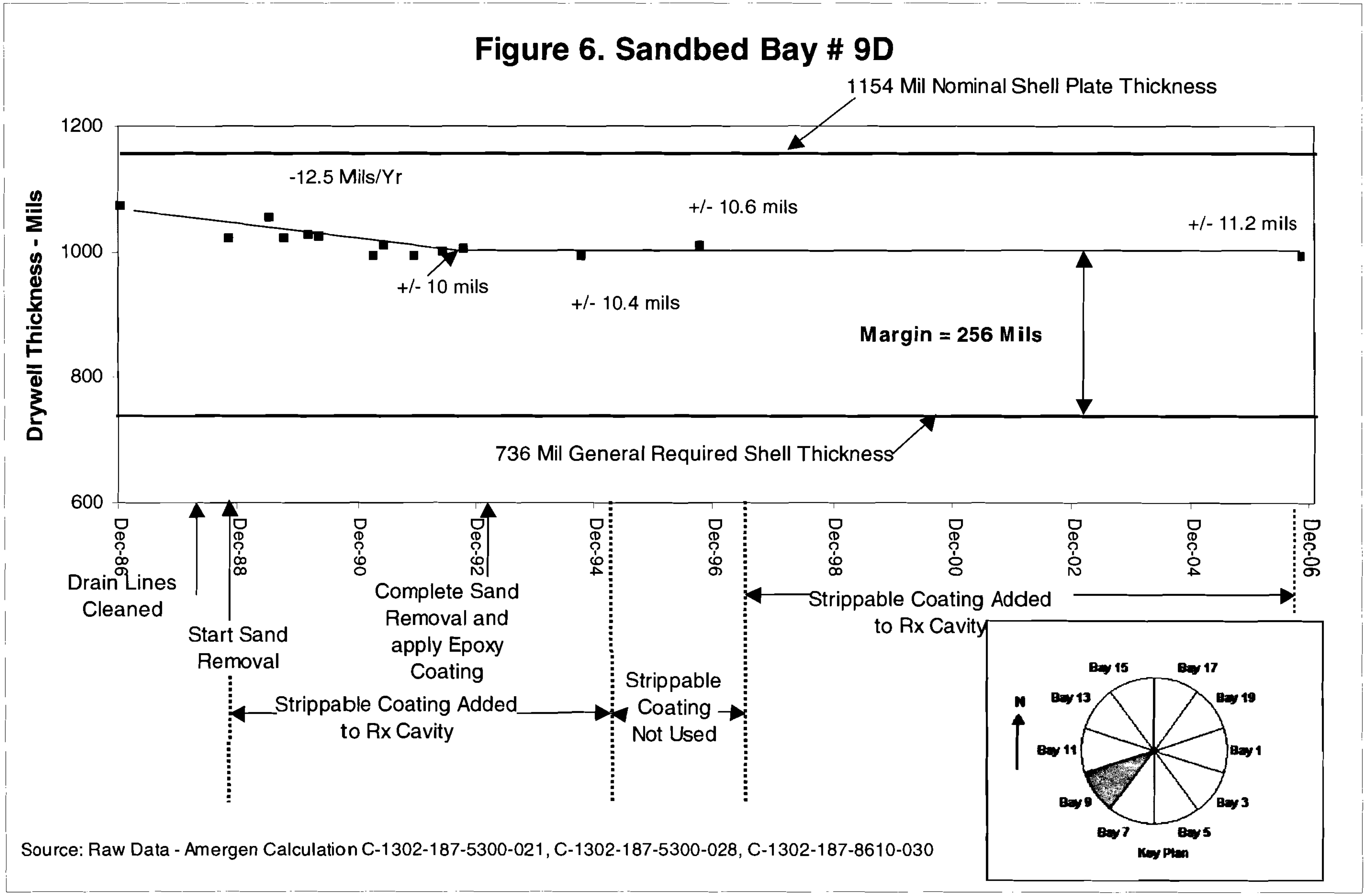


Figure 6. Sandbed Bay # 9D
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
-12.5 Mils/Yr
+/- 10.6 mils
+/- 11.2 mils
+/- 10 mils
+/- 10.4 mils
Margin = 256 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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

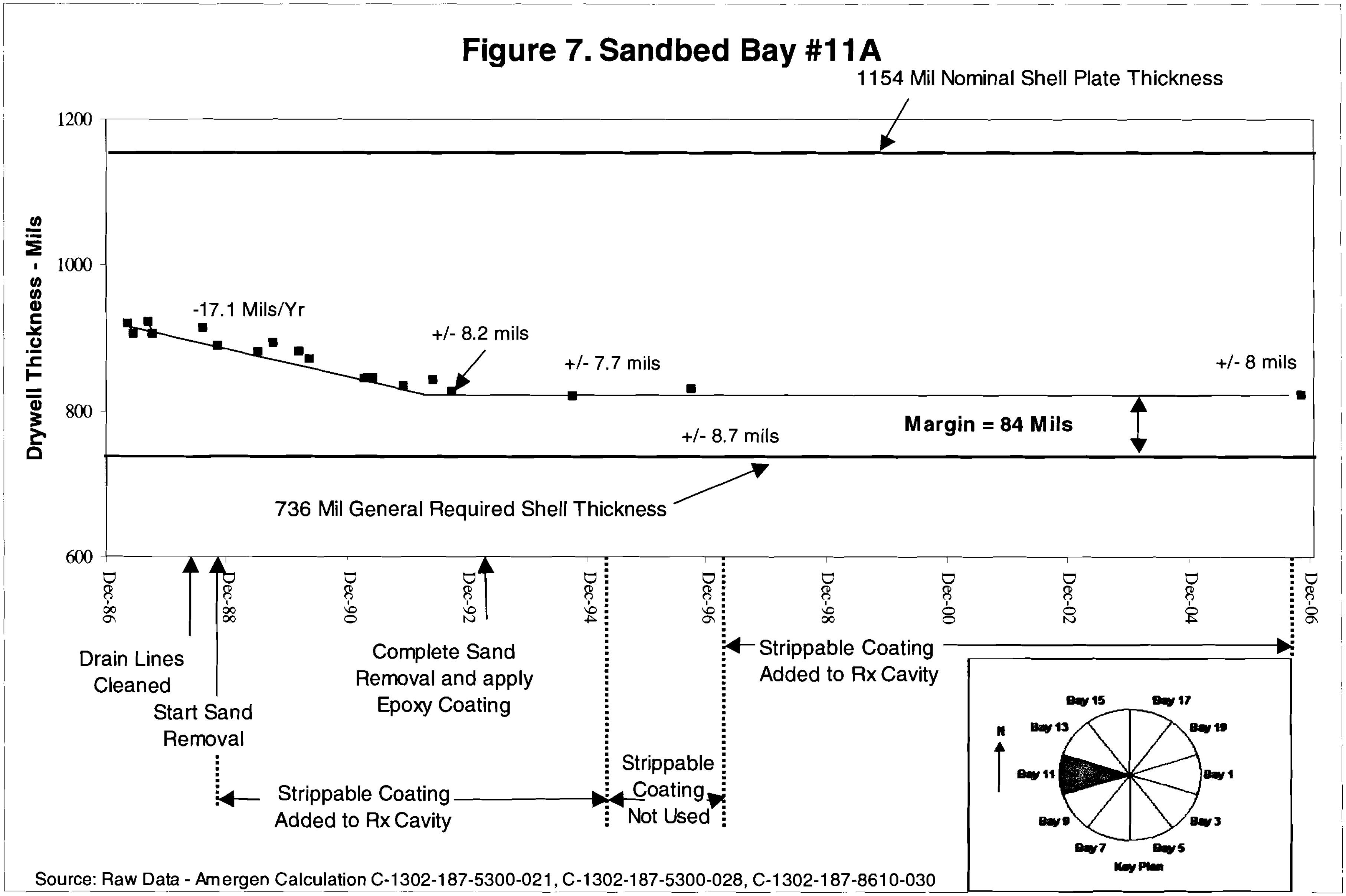


Figure 7. Sandbed Bay #11A
1154 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
1200
1000
800
600
-17.1 Mils/Yr
+/- 8.2 mils
+/- 7.7 mils
+/- 8 mils
Margin = 84 Mils
+/- 8.7 mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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

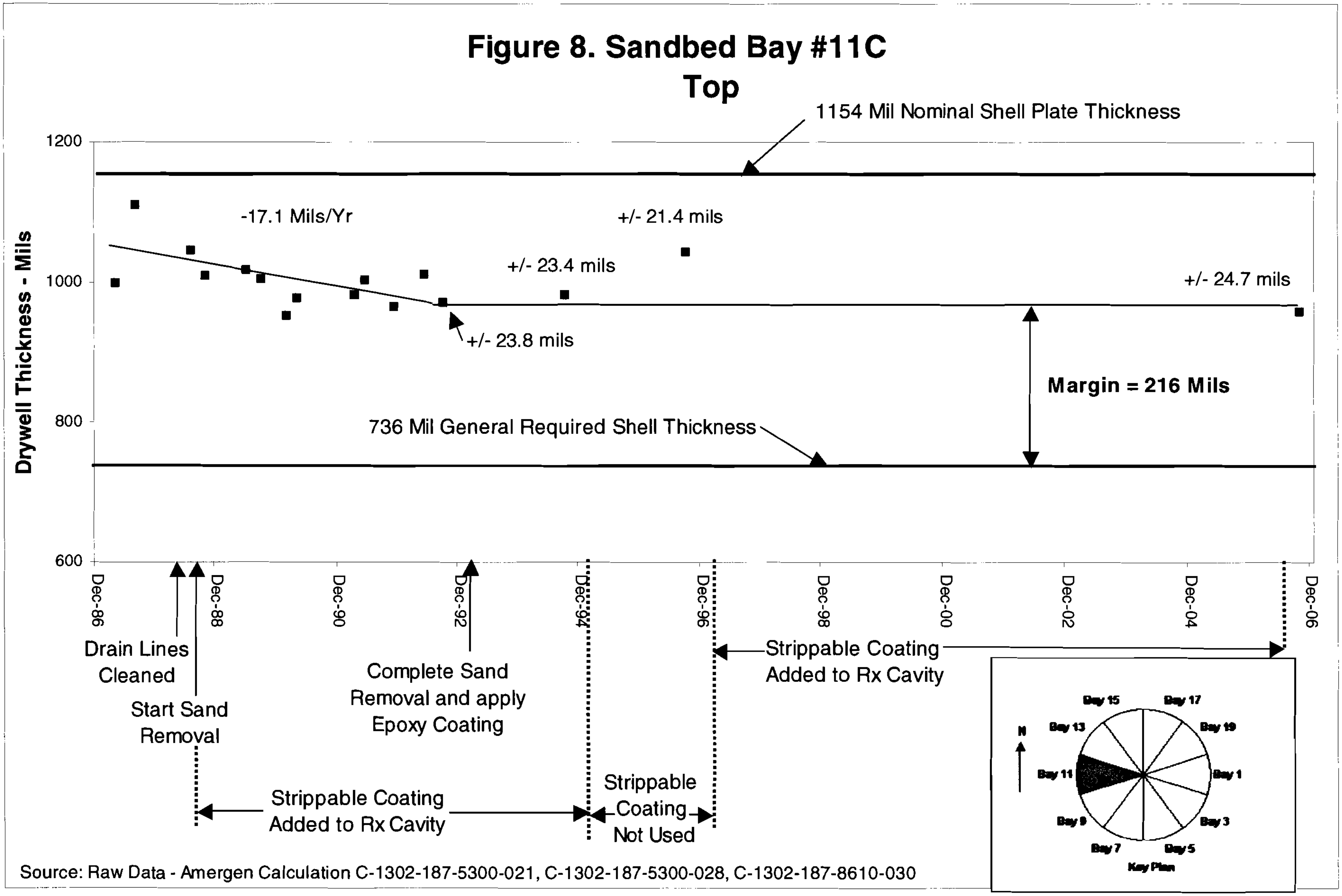
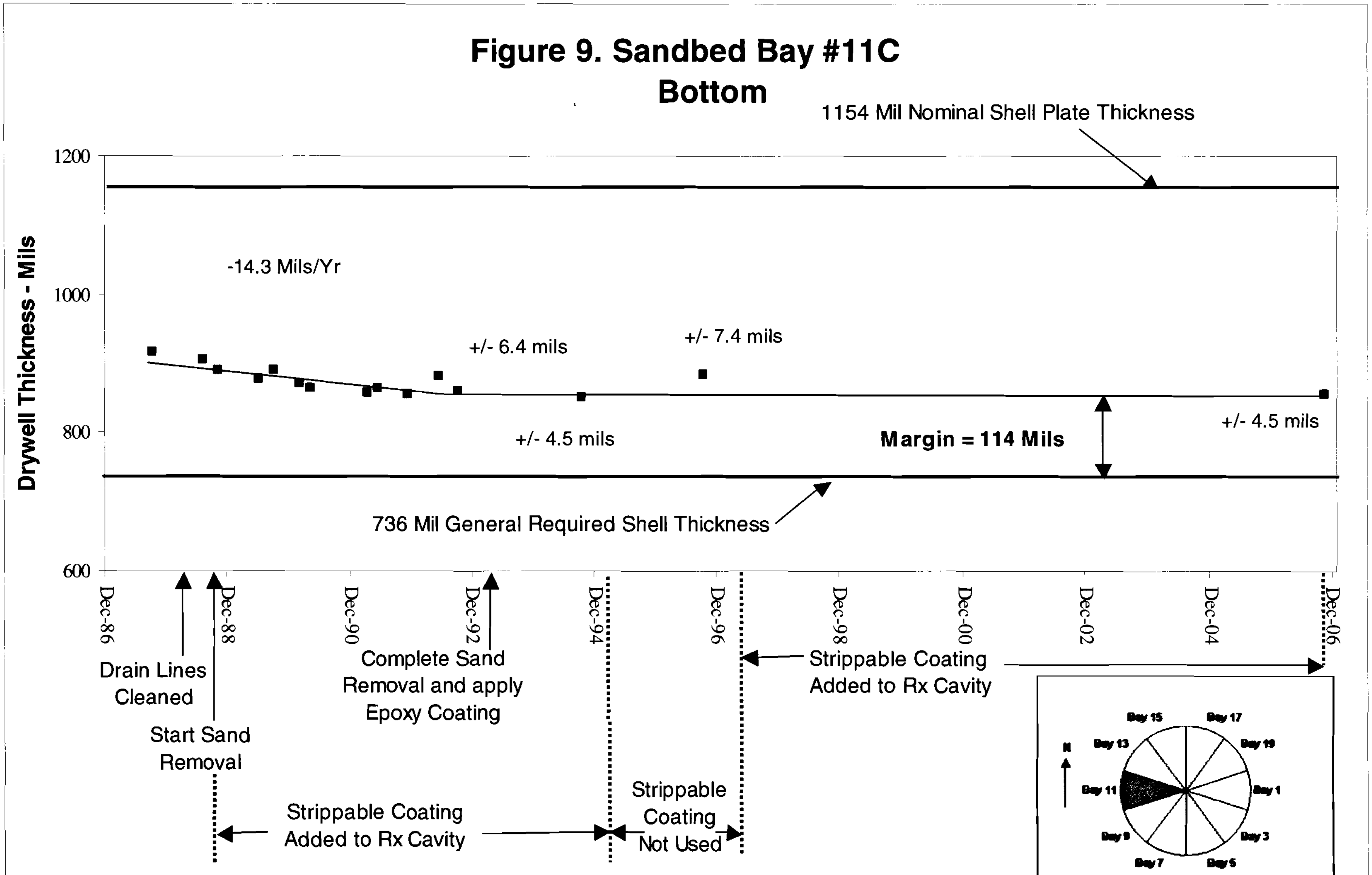


Figure 8. Sandbed Bay #11C
Top
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
-17.1 Mils/Yr
+/- 21.4 mils
+/- 23.4 mils
+/- 24.7 mils
+/- 23.8 mils
Margin = 216 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
Drain Lines Cleaned
Start Sand Removal
Complete Sand Removal and apply Epoxy Coating
Strippable Coating Added to Rx Cavity
Strippable Coating Added to Rx Cavity
Strippable Coating Not Used
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



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

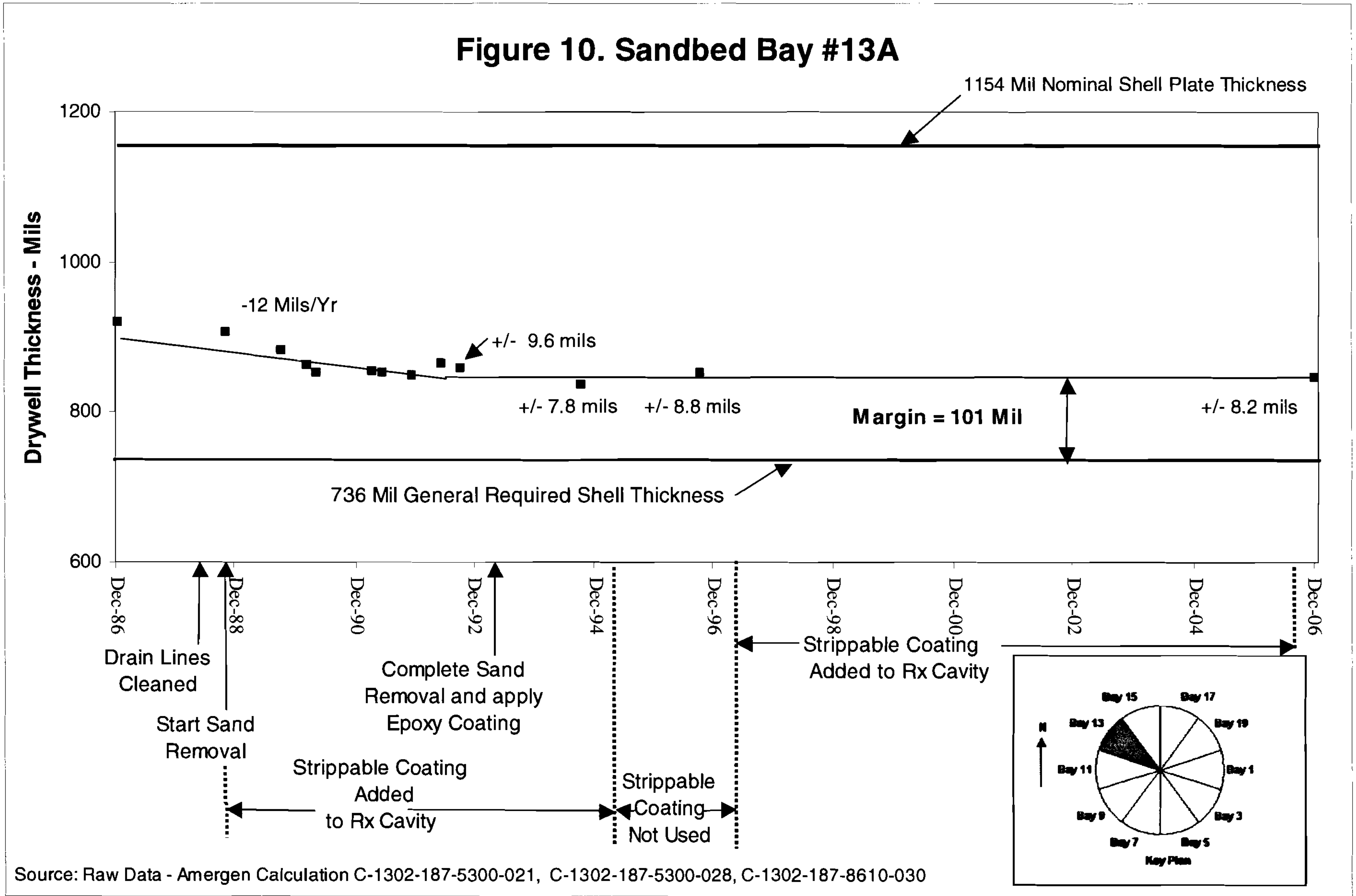
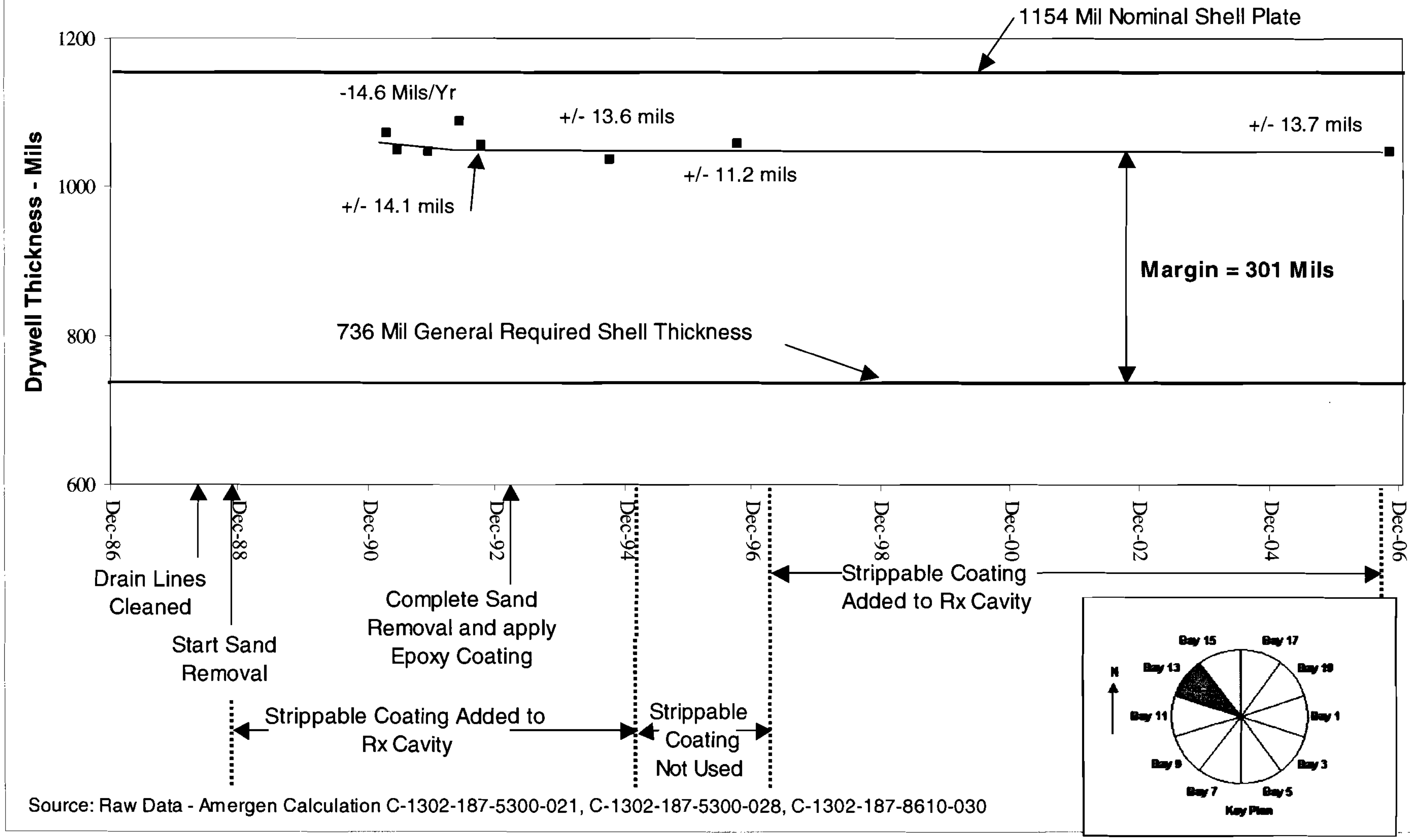
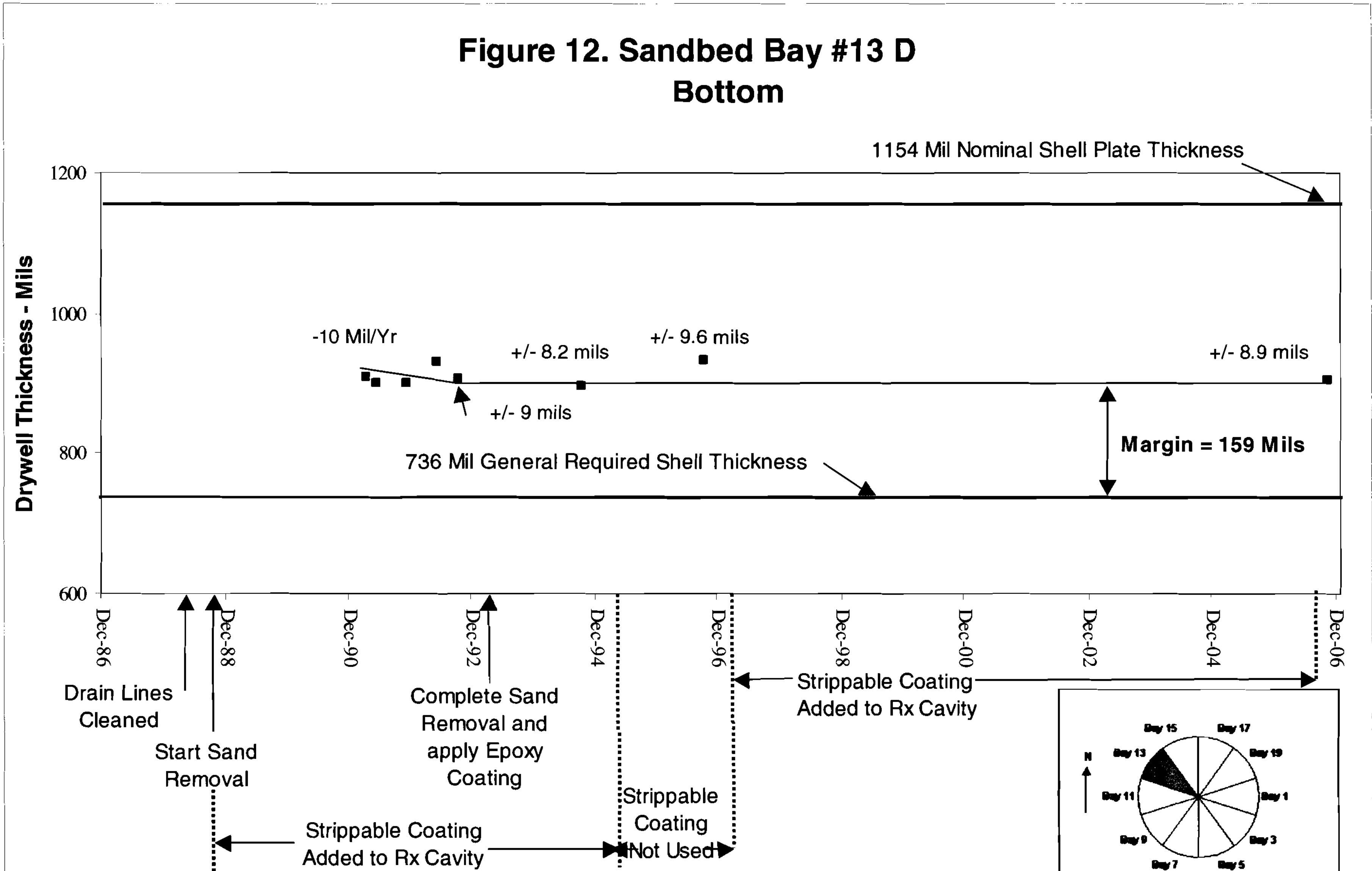


Figure 10. Sandbed Bay #13A
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
-12 Mils/Yr
+/- 9.6 mils
+/- 7.8 mils
+/- 8.8 mils
Margin = 101 Mil
+/- 8.2 mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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
Key Plan
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 11. Sandbed Bay #13D
Top

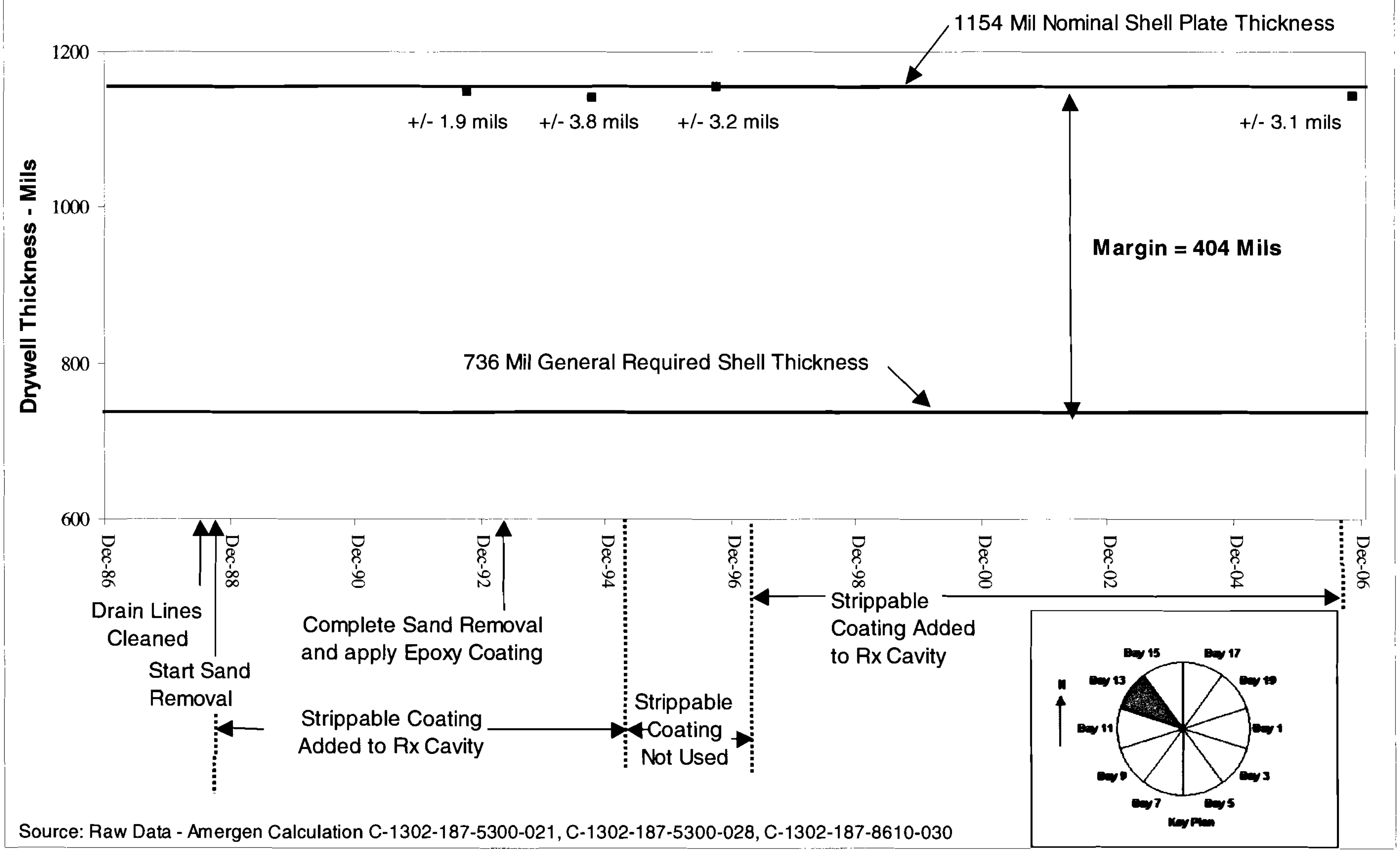


Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030



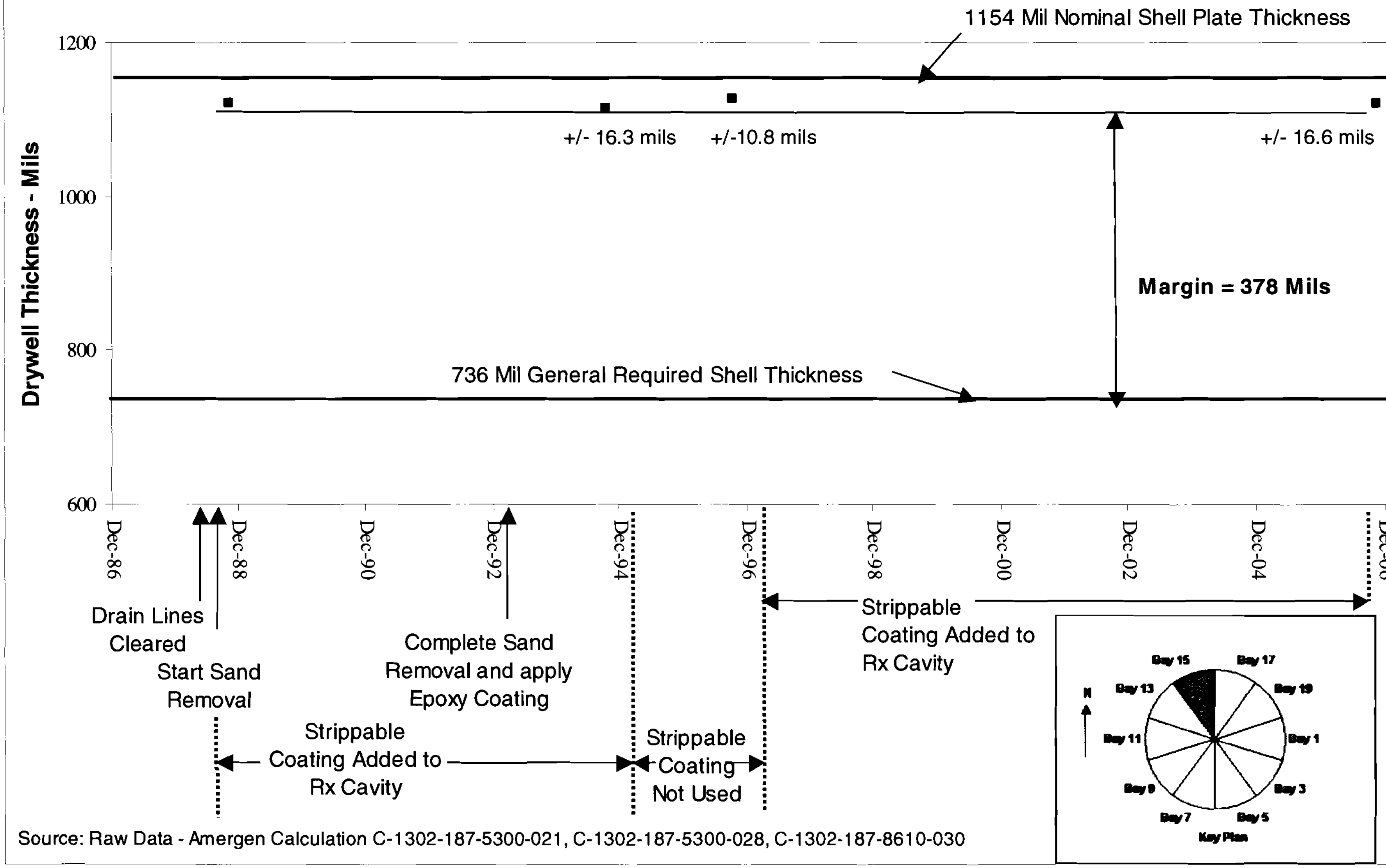
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 13. Sandbed Bay # 13C



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 14. Sandbed Bay # 15A



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

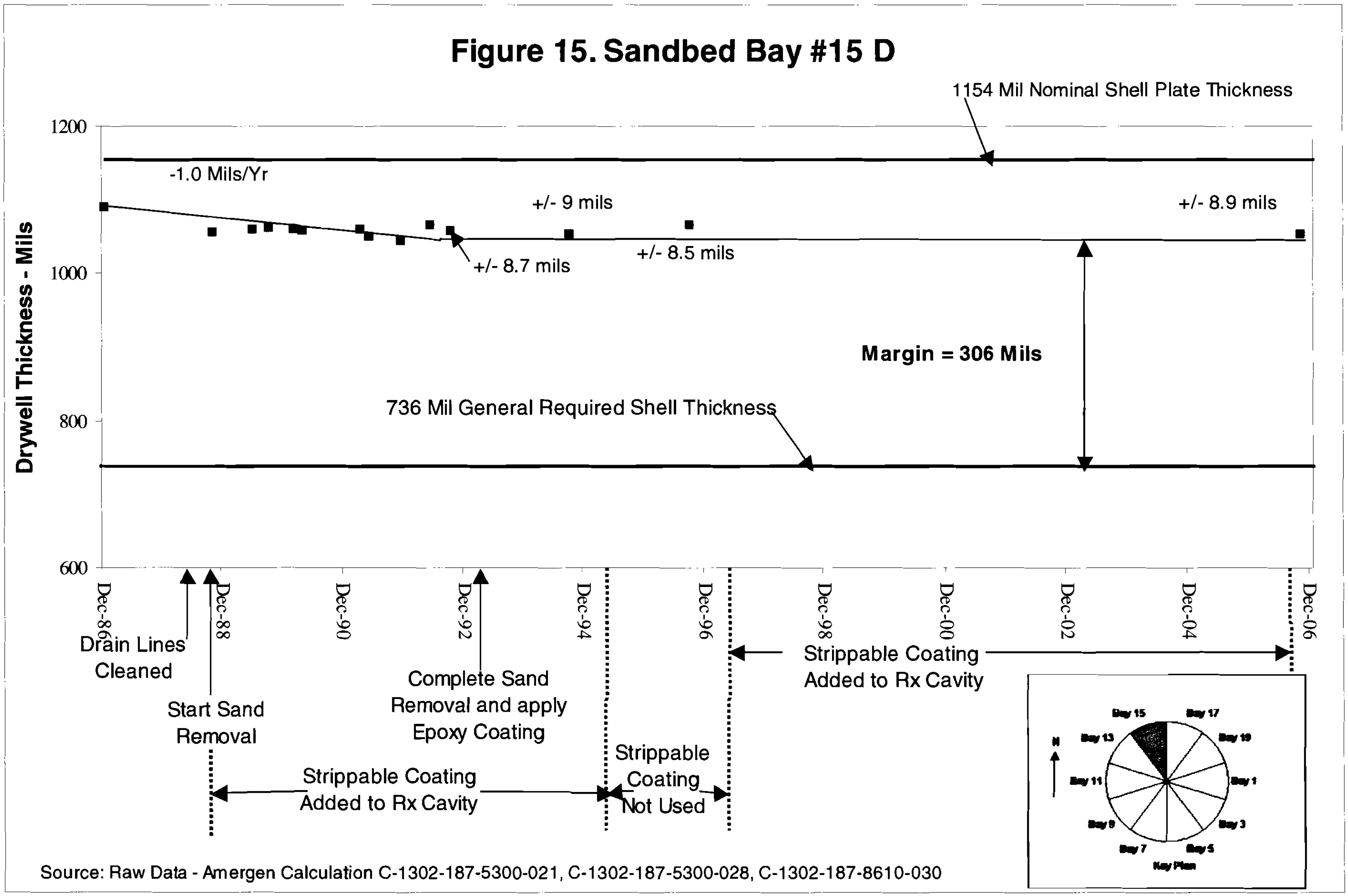


Figure 15. Sandbed Bay #15 D
1154 Mil Nominal Shell Plate Thickness
-1.0 Mils/Yr
+/- 9 mils
+/- 8.9 mils
+/- 8.5 mils
+/- 8.7 mils
Margin = 306 Mils
736 Mil General Required Shell Thickness
Drywell Thickness - Mils
1200
1000
800
600
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

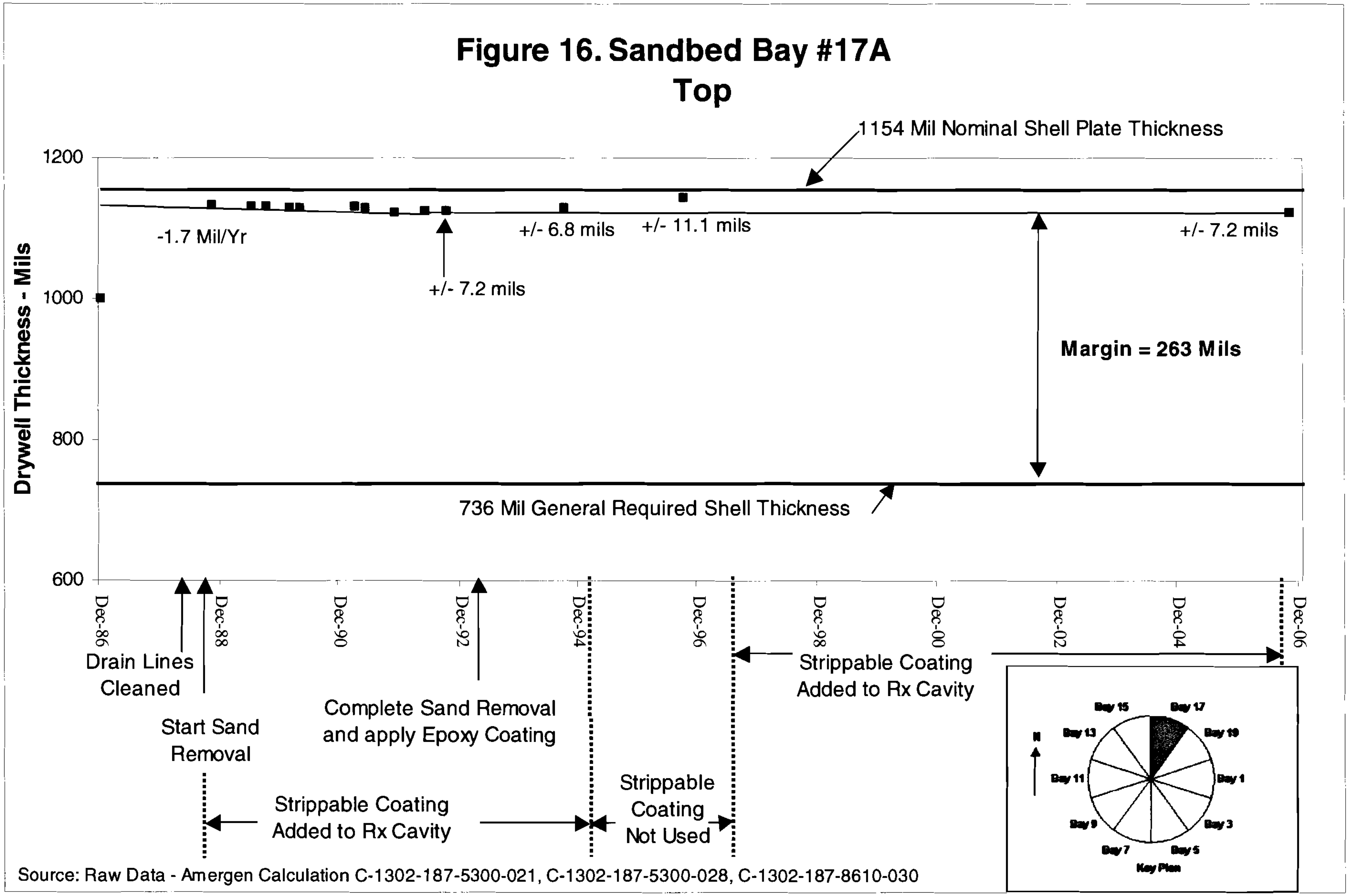
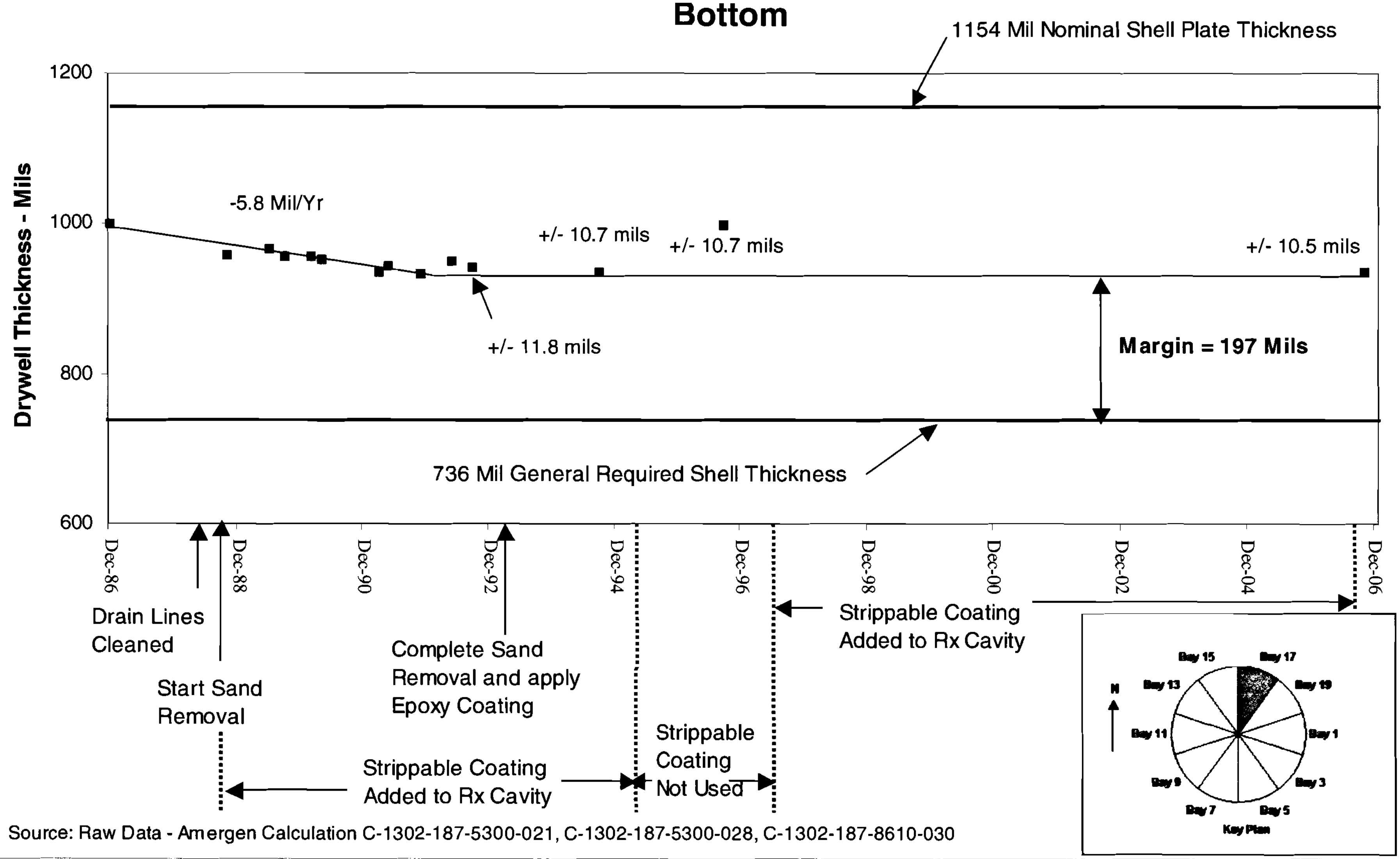


Figure 16. Sandbed Bay #17A
Top
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
-1.7 Mil/Yr
+/- 7.2 mils
+/- 6.8 mils
+/- 11.1 mils
+/- 7.2 mils
Margin = 263 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 17. Sandbed Bay #17A
Bottom



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

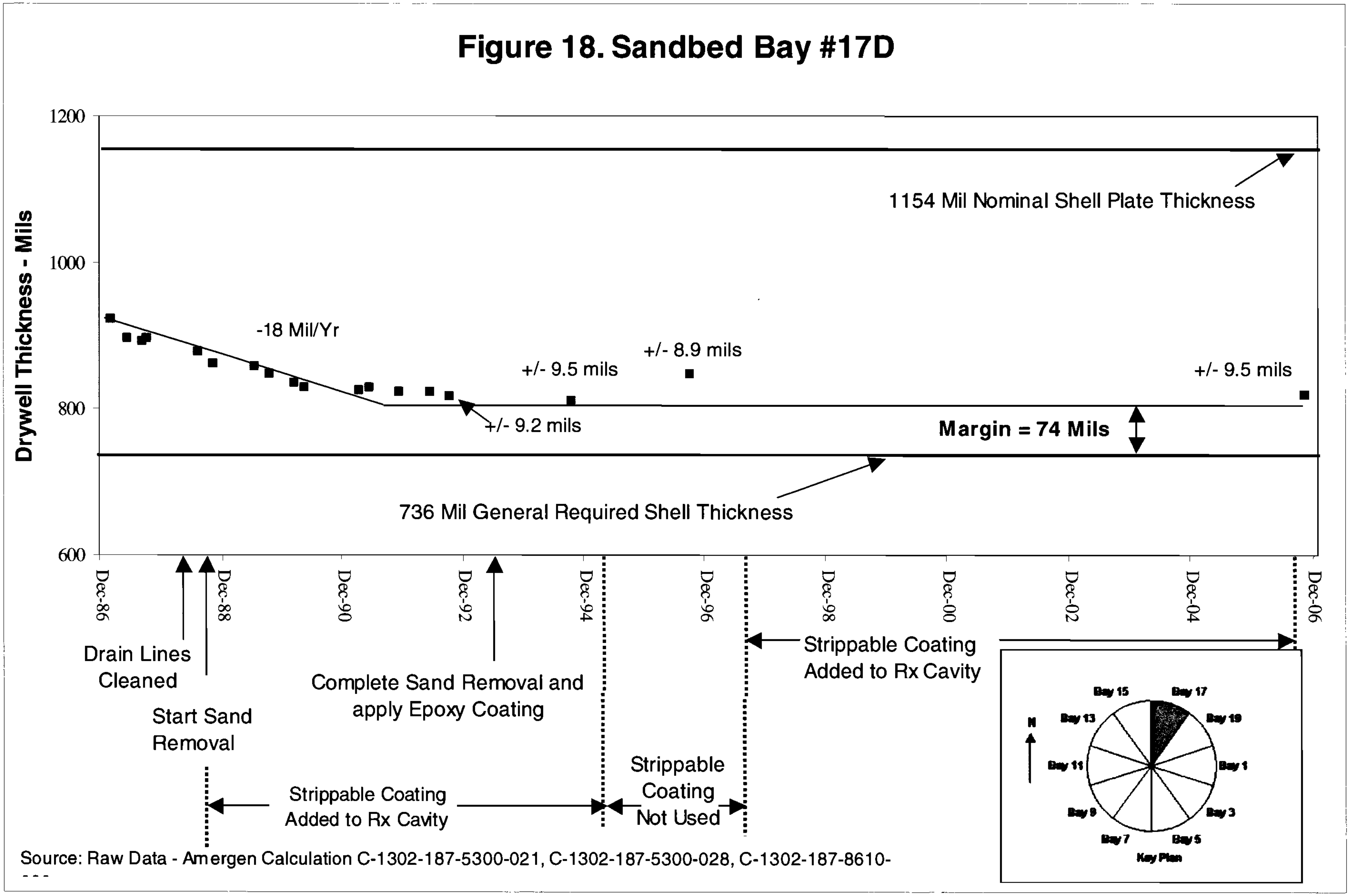
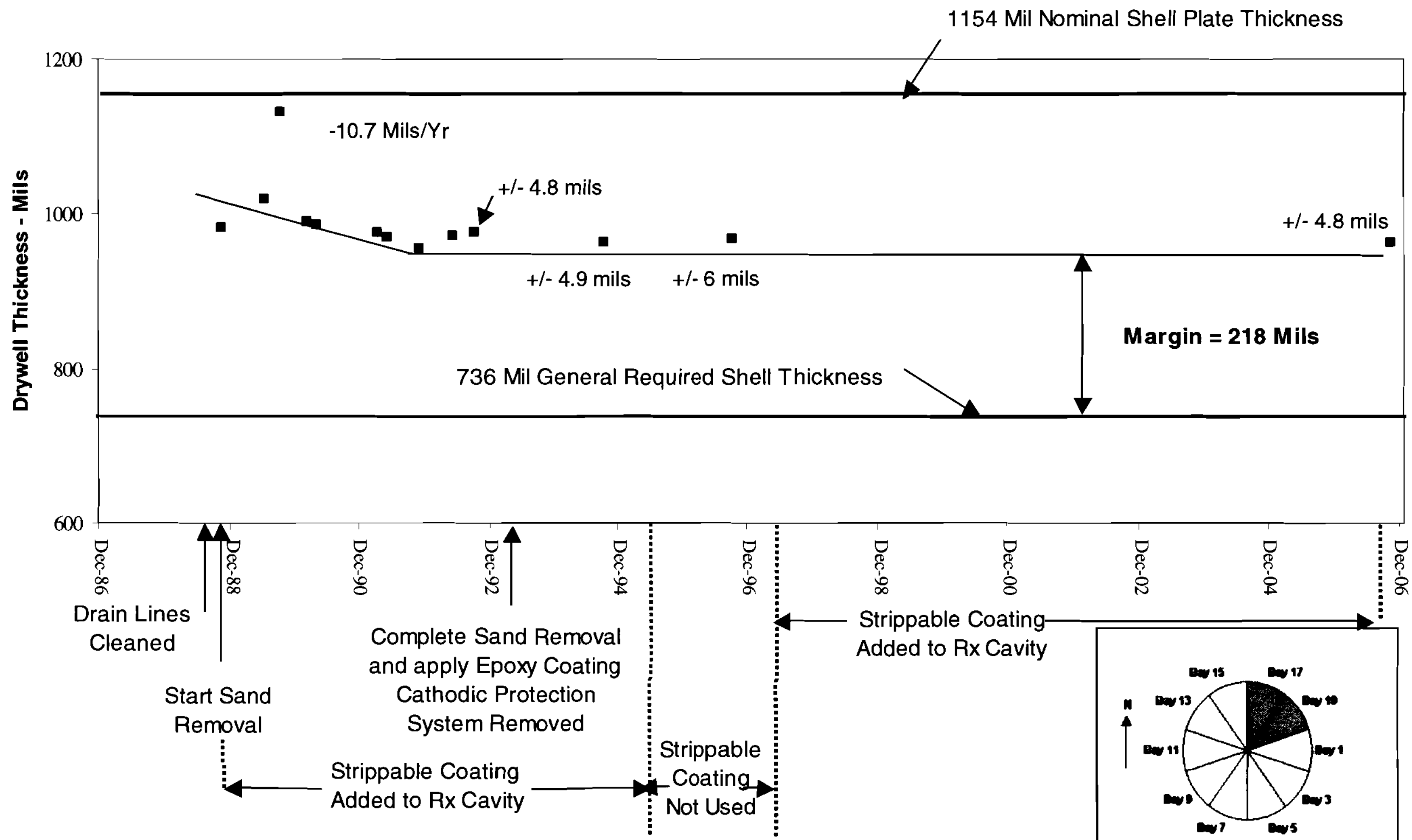


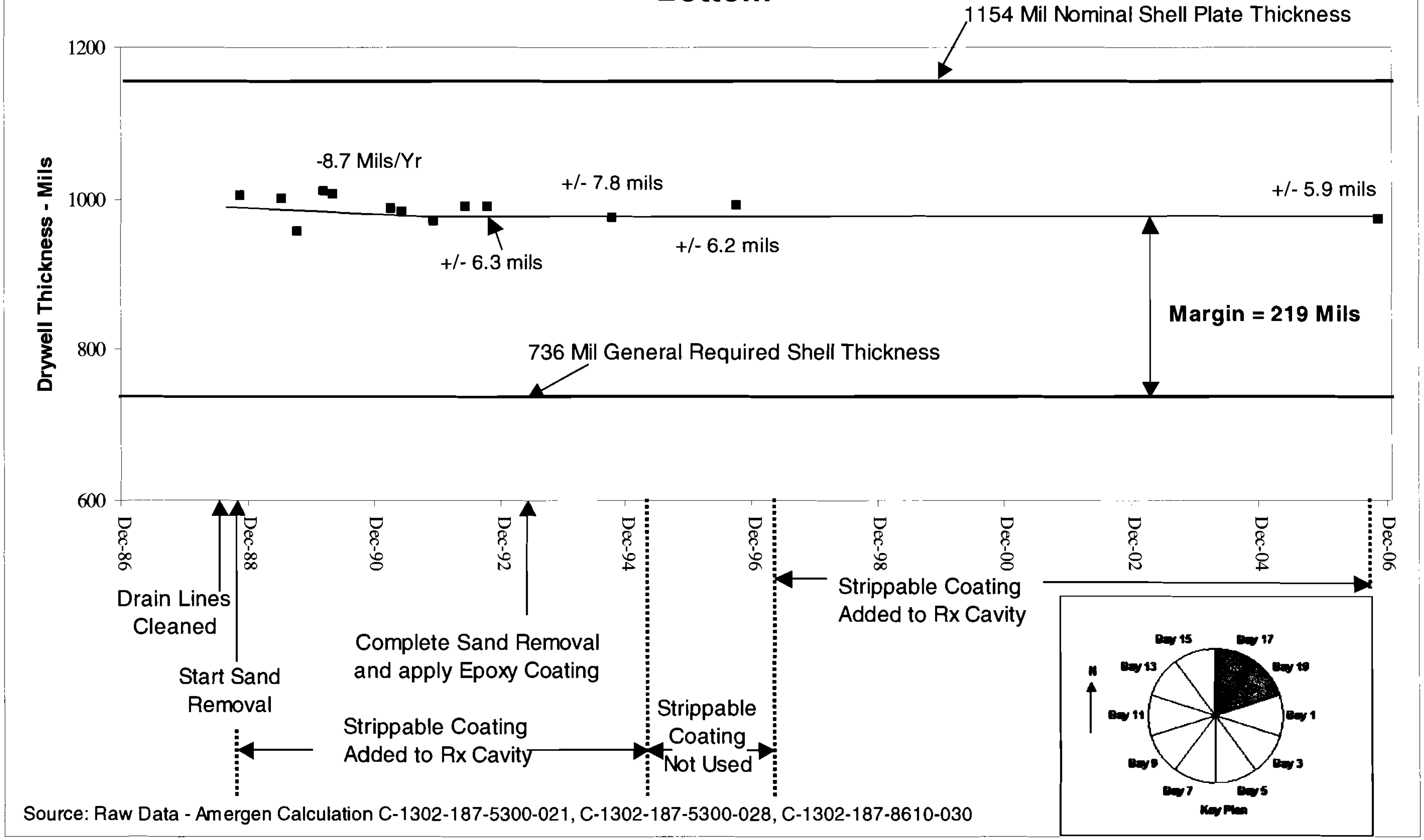
Figure 18. Sandbed Bay #17D
1200
1000
800
600
Drywell Thickness - Mils
1154 Mil Nominal Shell Plate Thickness
-18 Mil/Yr
+/- 8.9 mils
+/- 9.5 mils
+/- 9.5 mils
+/- 9.2 mils
Margin = 74 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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-

Figure 19. Sandbed Bay #17/19
Frame Top



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 20. Sandbed Bays # 17/19
Bottom



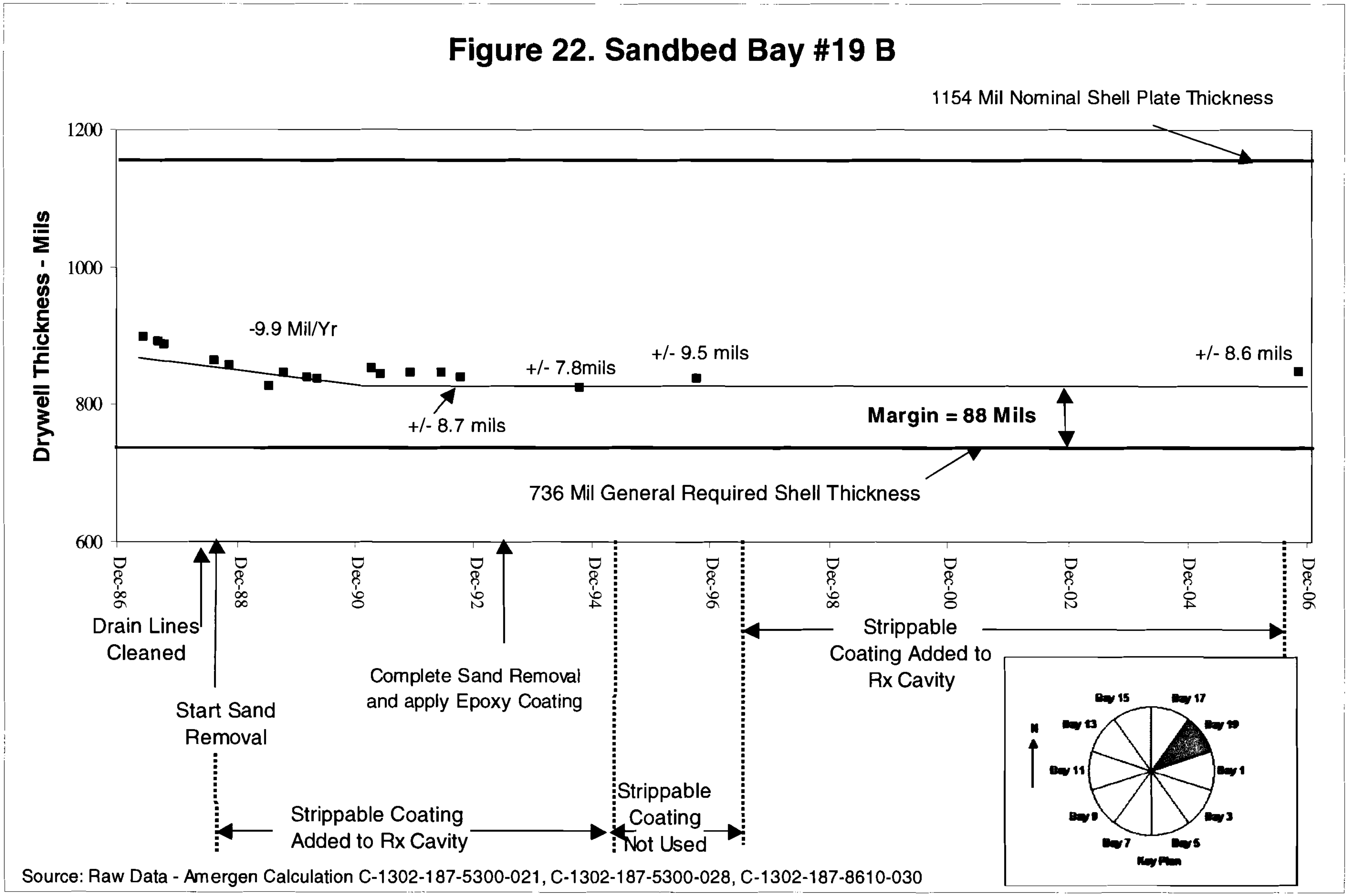


Figure 22. Sandbed Bay #19 B
1154 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
1200
1000
800
600
-9.9 Mil/Yr
+/- 7.8mils
+/- 9.5 mils
+/- 8.6 mils
+/- 8.7 mils
Margin = 88 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
Dec-06
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

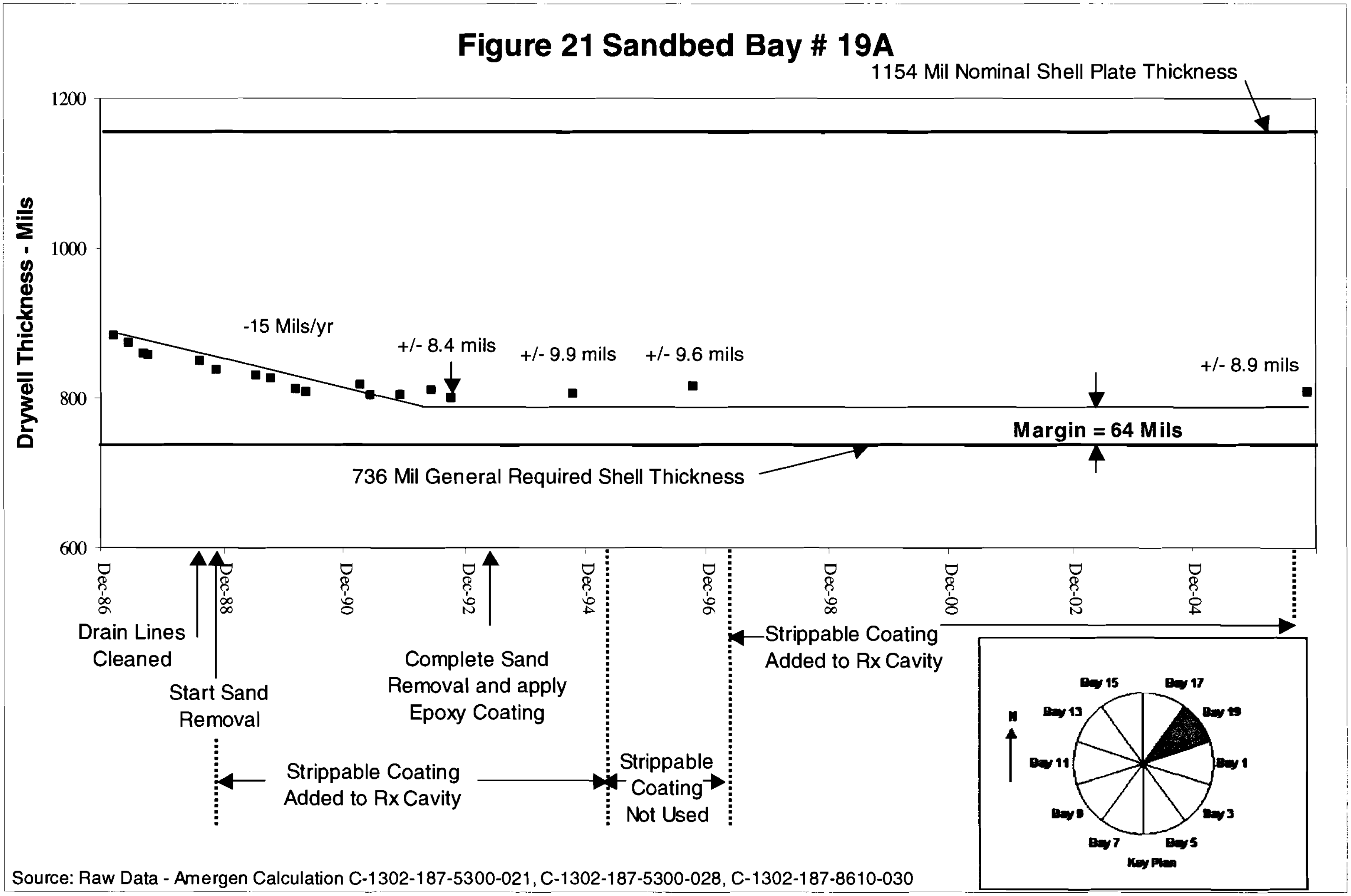
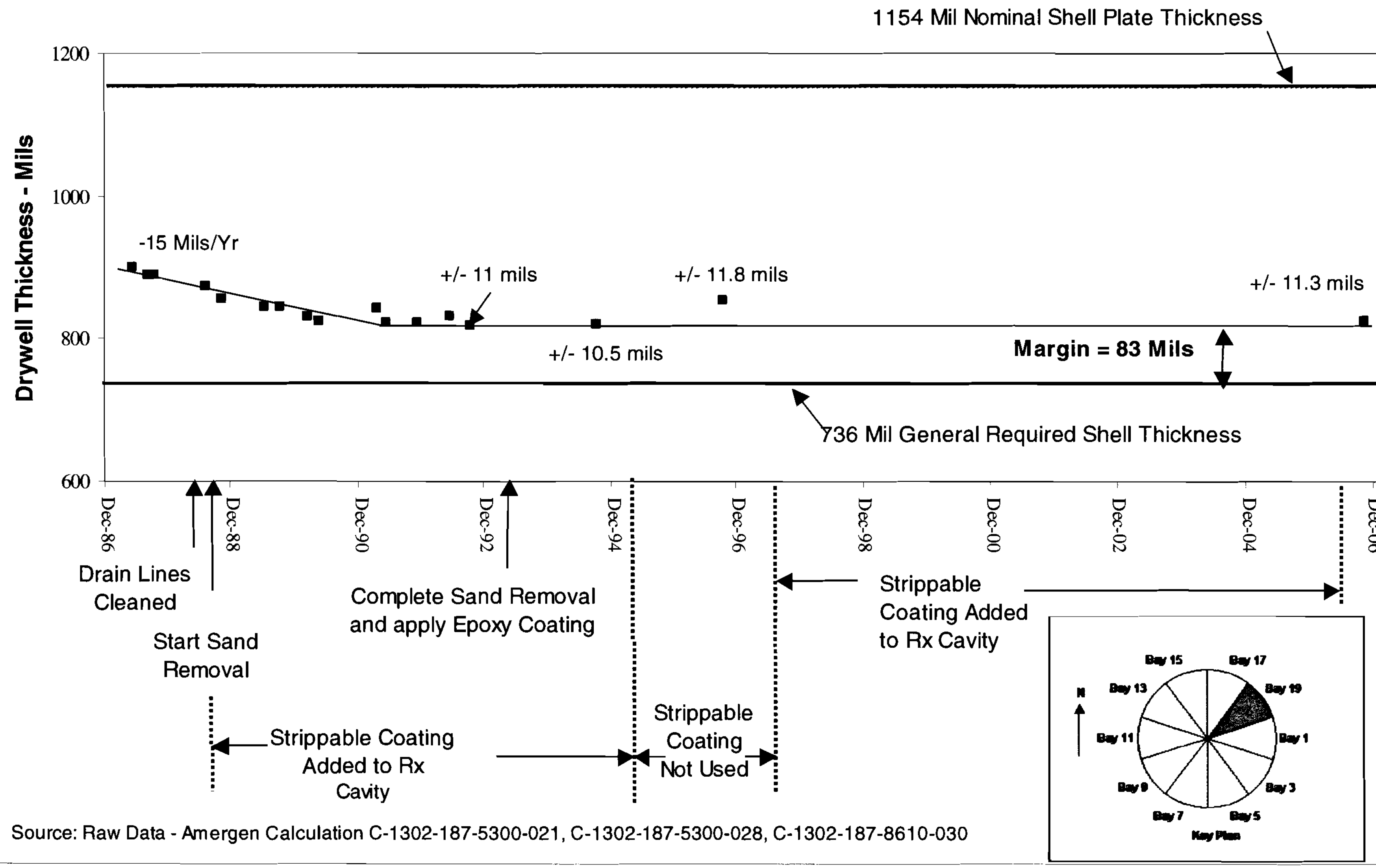


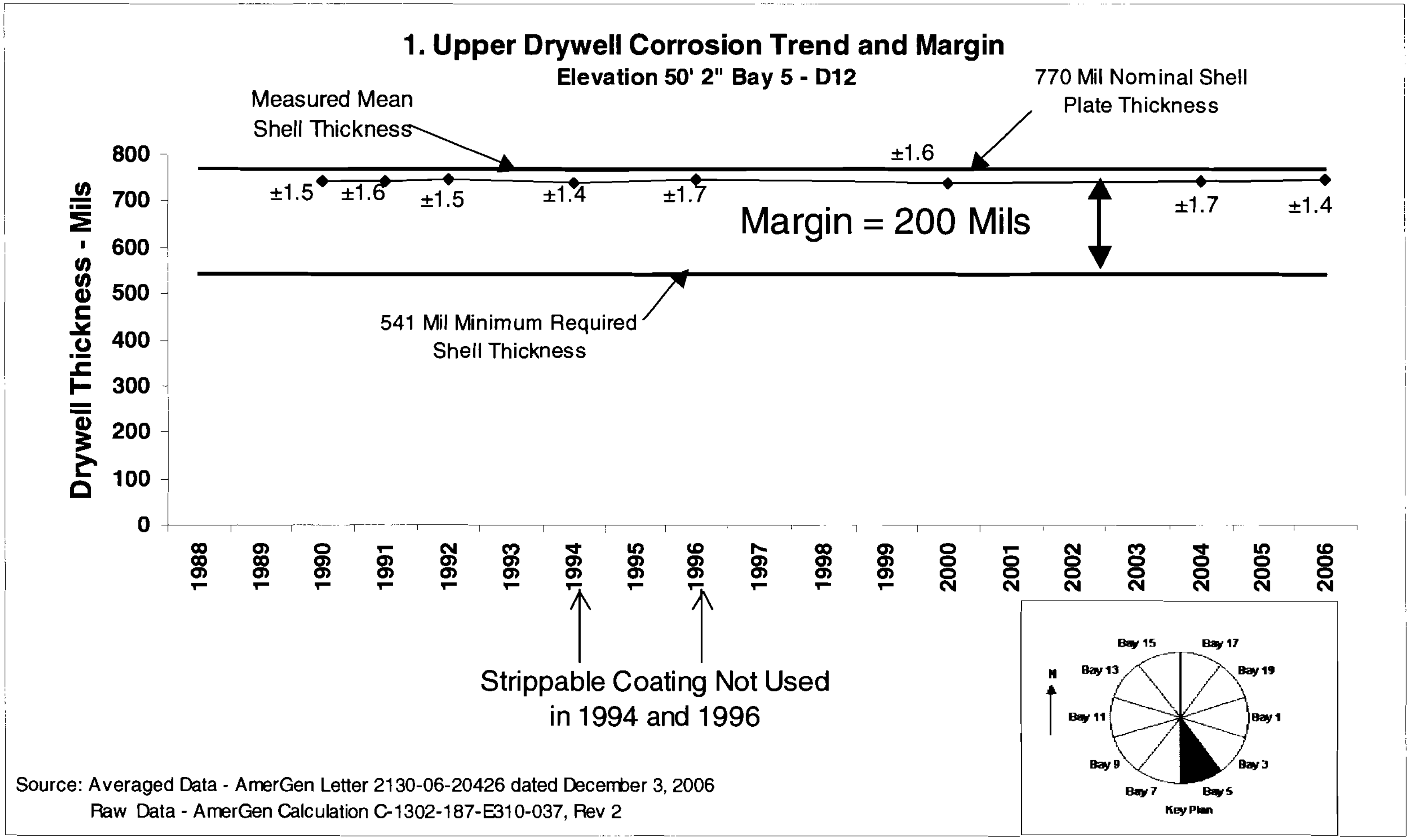
Figure 21 Sandbed Bay # 19A
1154 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
1200
1000
800
600
-15 Mils/yr
+/- 8.4 mils
+/- 9.9 mils
+/- 9.6 mils
+/- 8.9 mils
Margin = 64 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
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

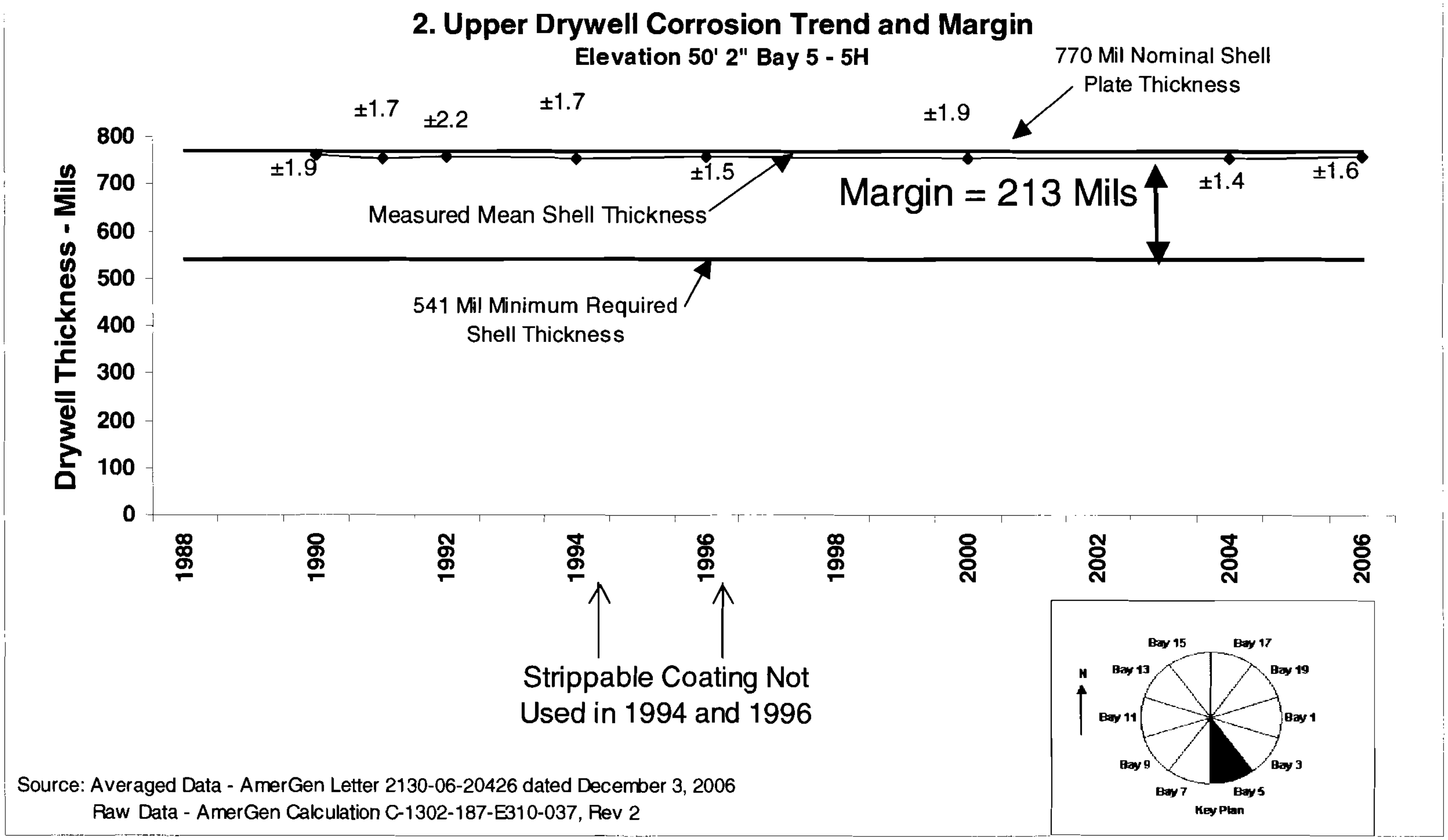
Figure 23. Sandbed Bay # 19C



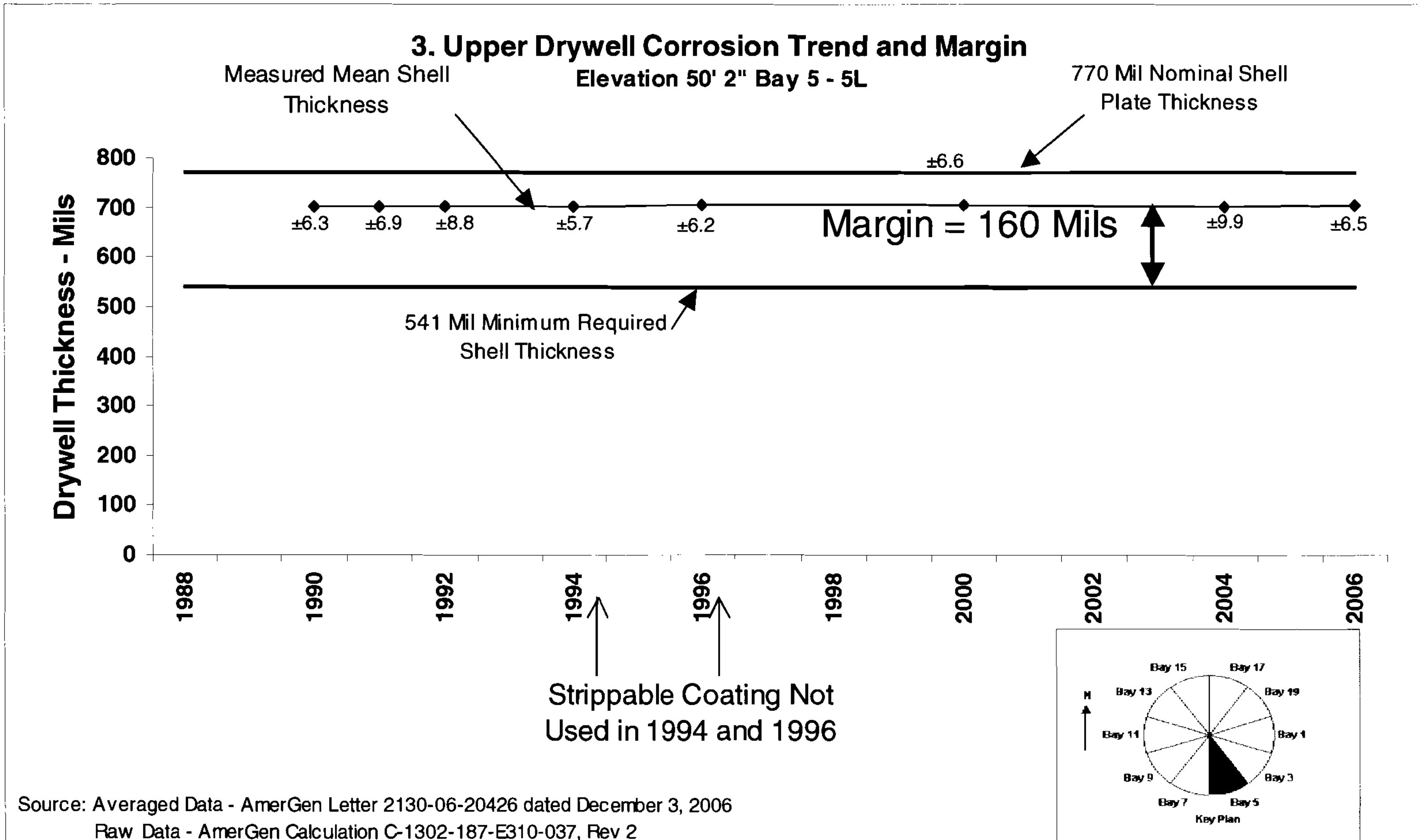
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Upper Drywell Trend

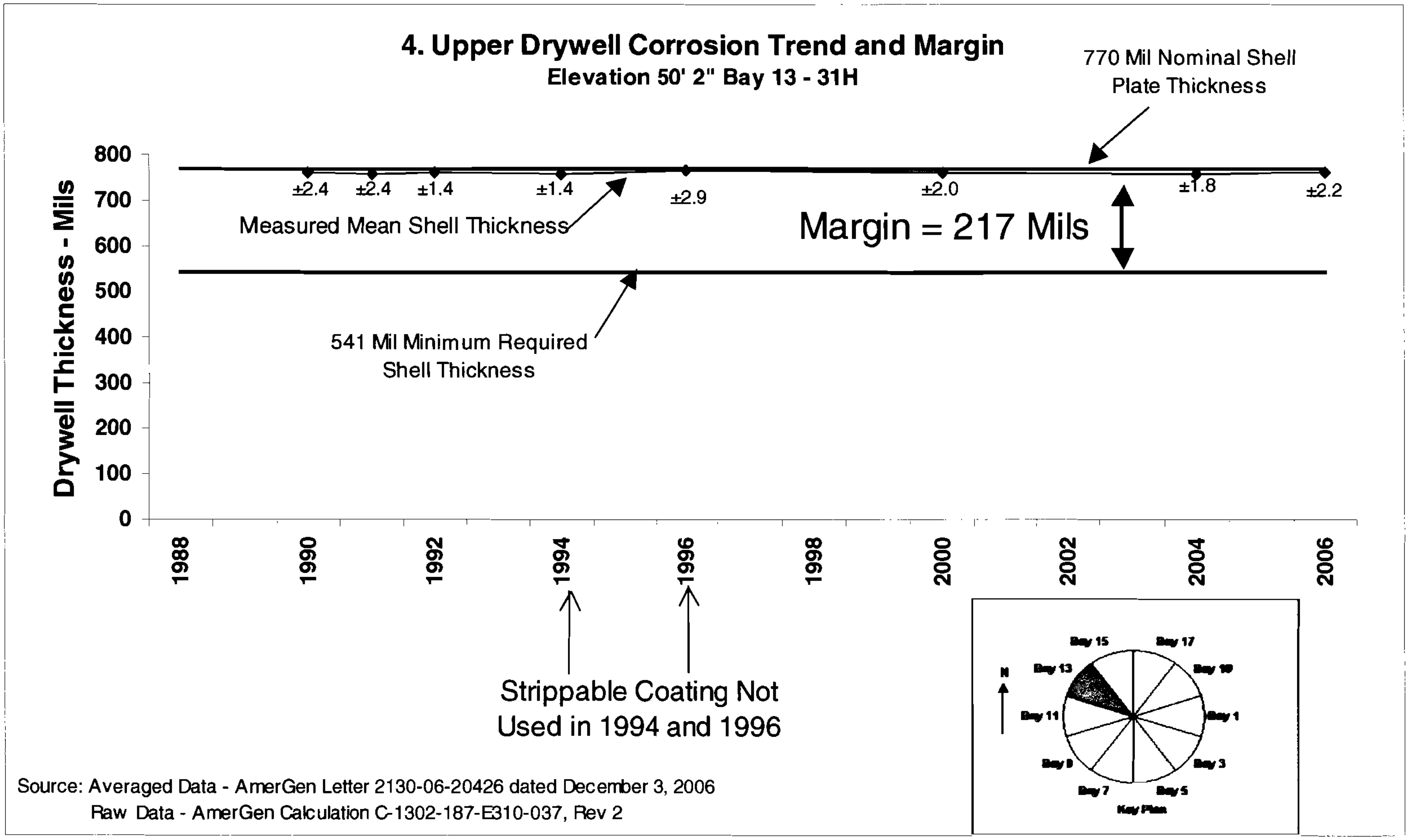

1. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 5 - D12
Measured Mean Shell Thickness
770 Mil Nominal Shell Plate Thickness
Margin = 200 Mils
541 Mil Minimum Required Shell Thickness
Drywell Thickness - Mils
±1.5
±1.6
±1.5
±1.4
±1.7
±1.6
±1.7
±1.4
0
100
200
300
400
500
600
700
800
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Bay 15
Bay 17
Bay 13
Bay 19
N
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan



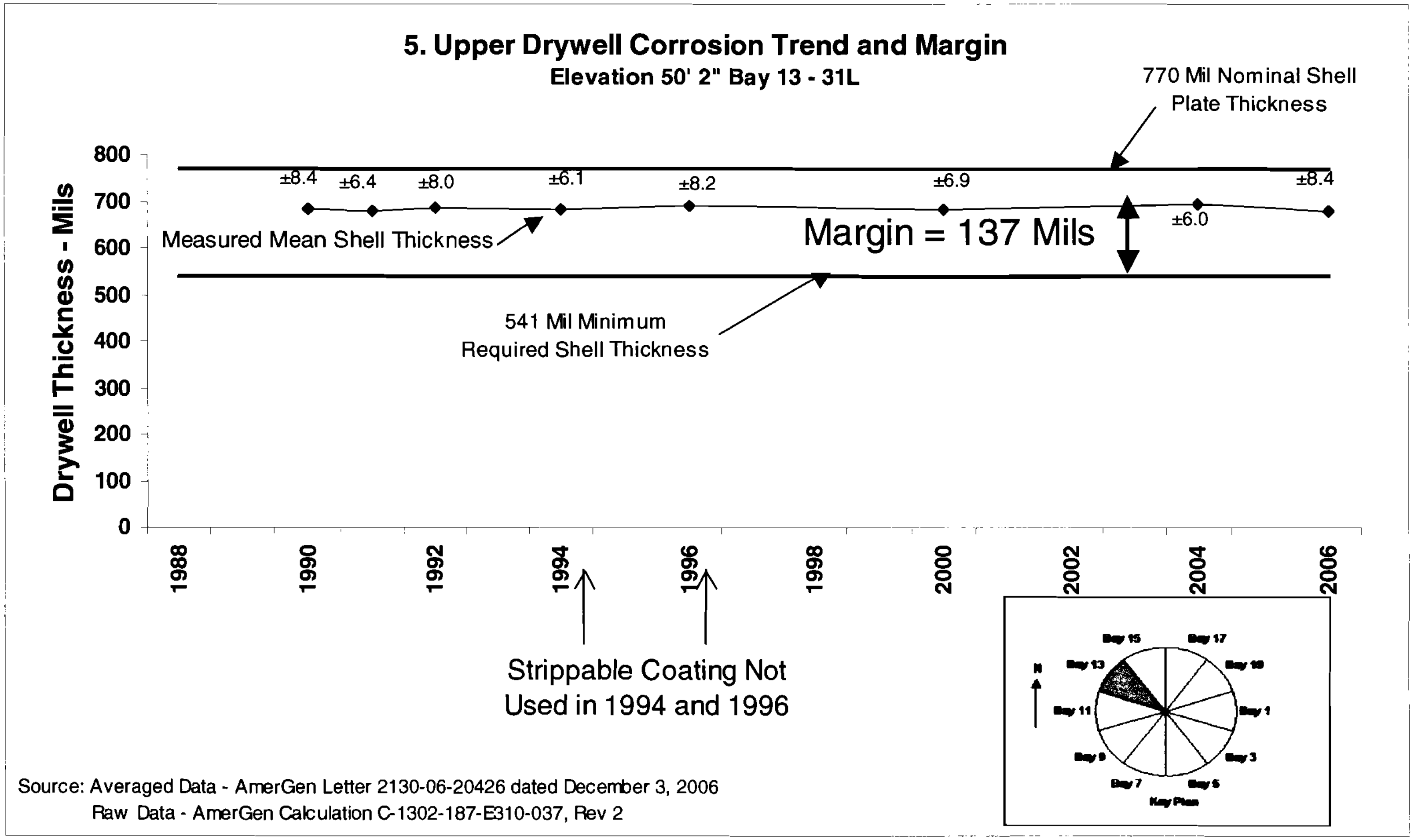
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

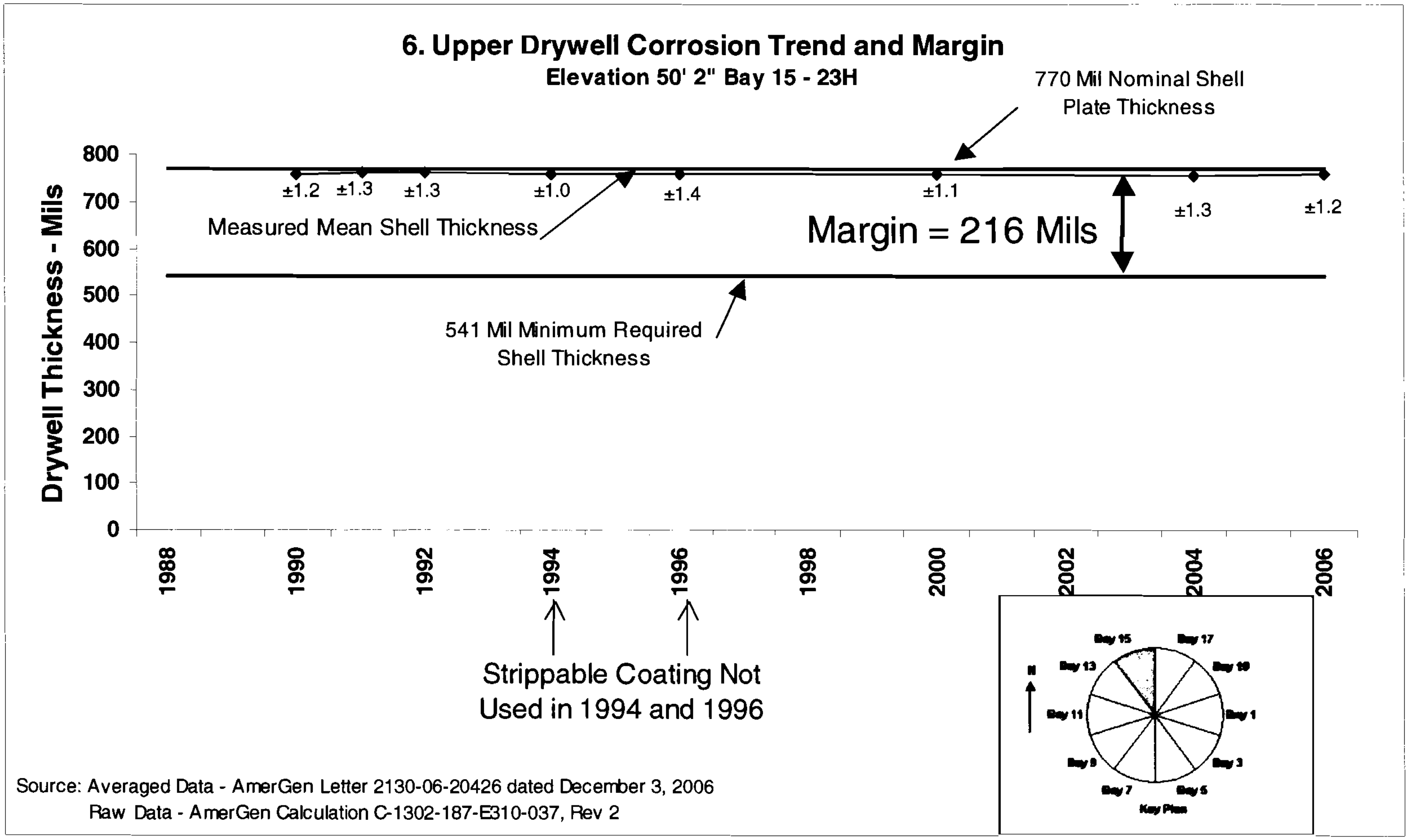


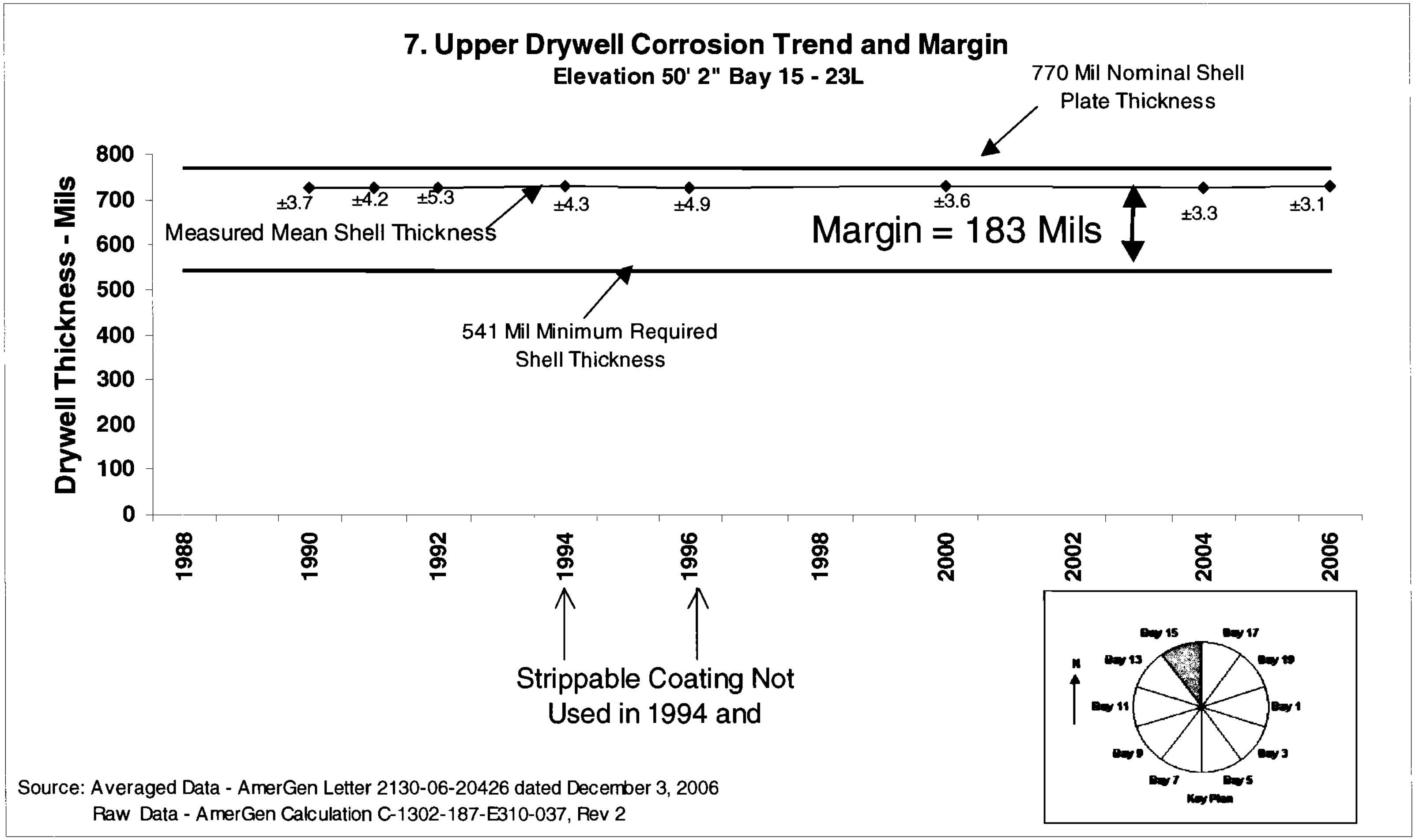
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

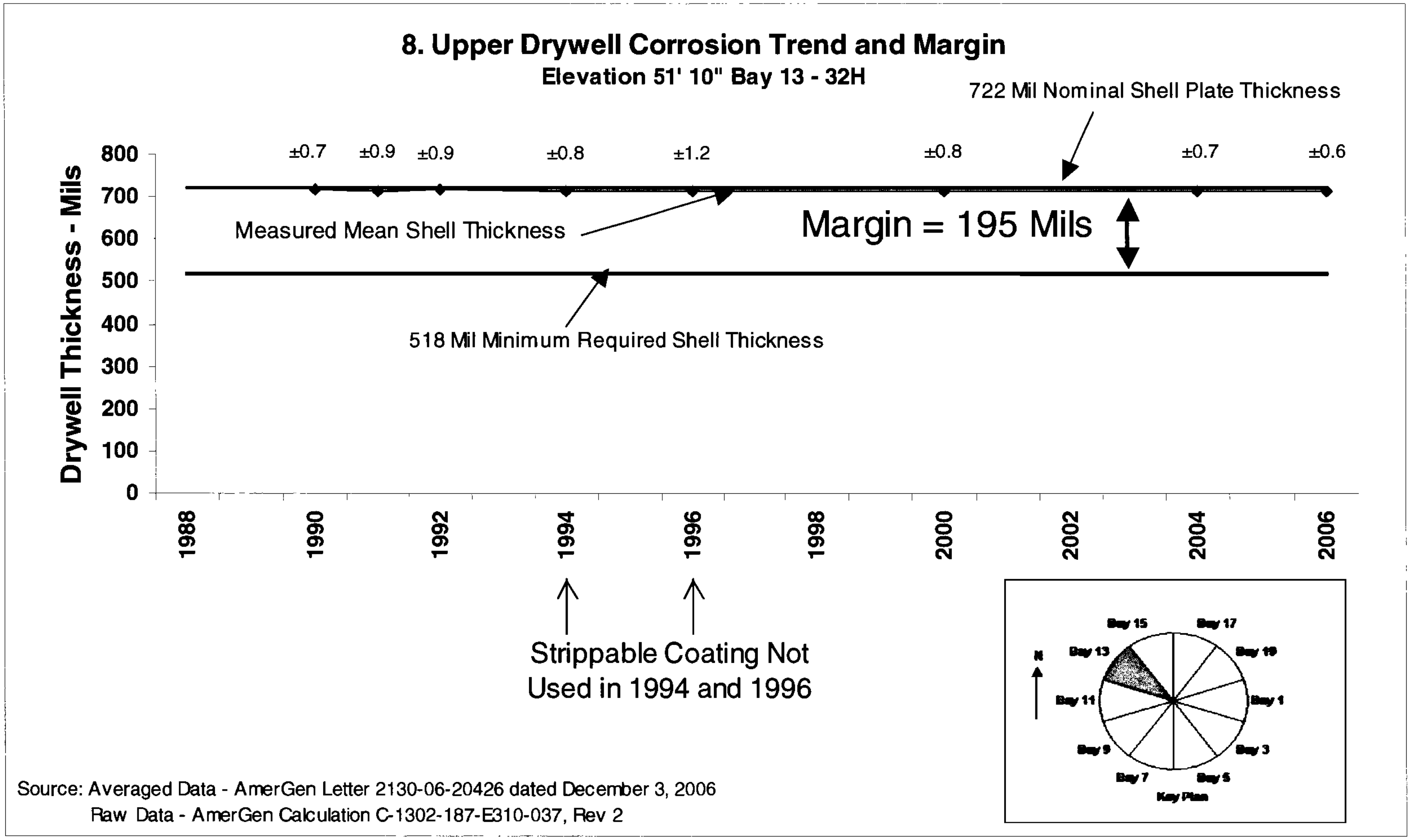


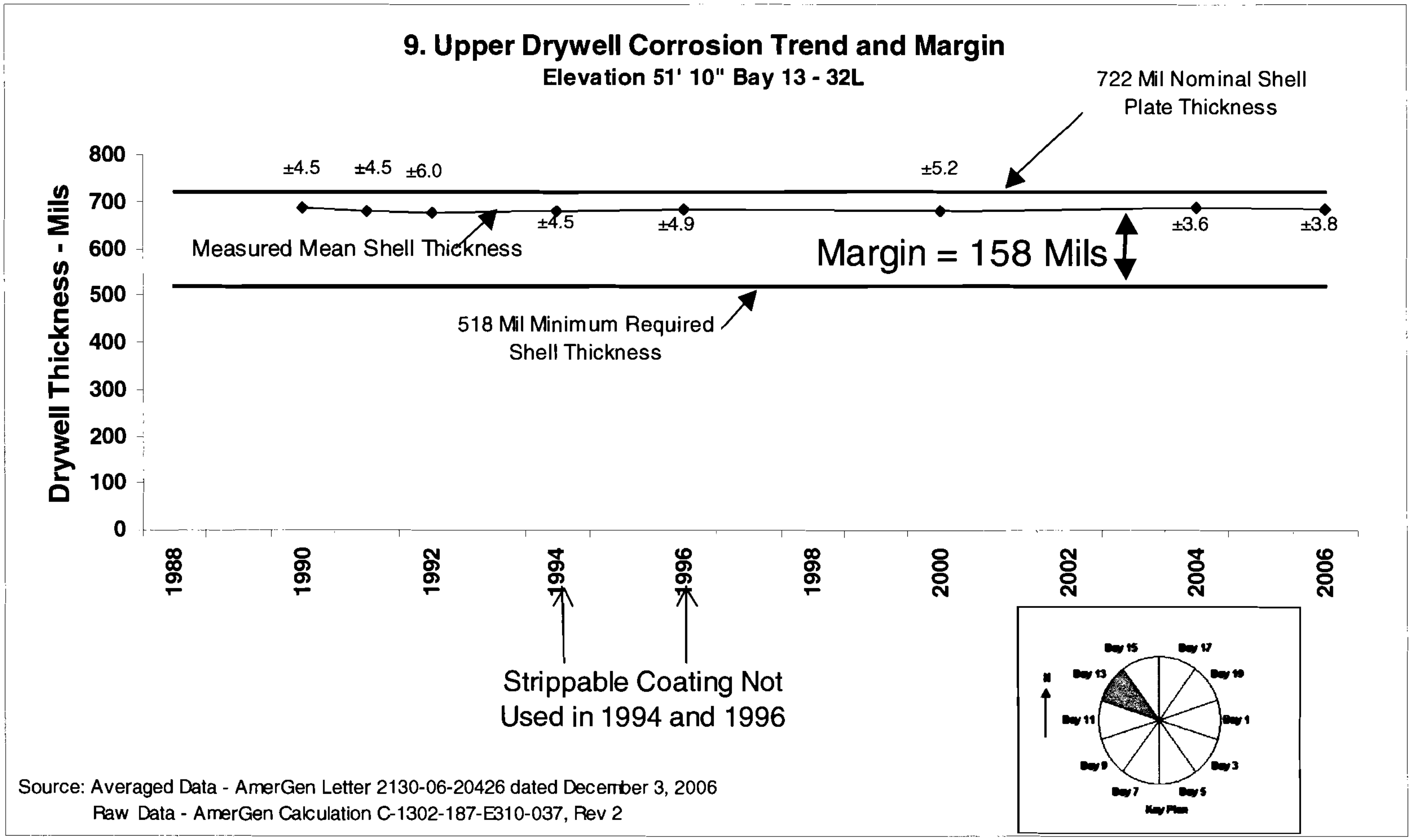
4. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 13 - 31H
770 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±2.4
±2.4
±1.4
±1.4
±2.9
±2.0
±1.8
±2.2
Measured Mean Shell Thickness
Margin = 217 Mils
541 Mil Minimum Required Shell Thickness
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

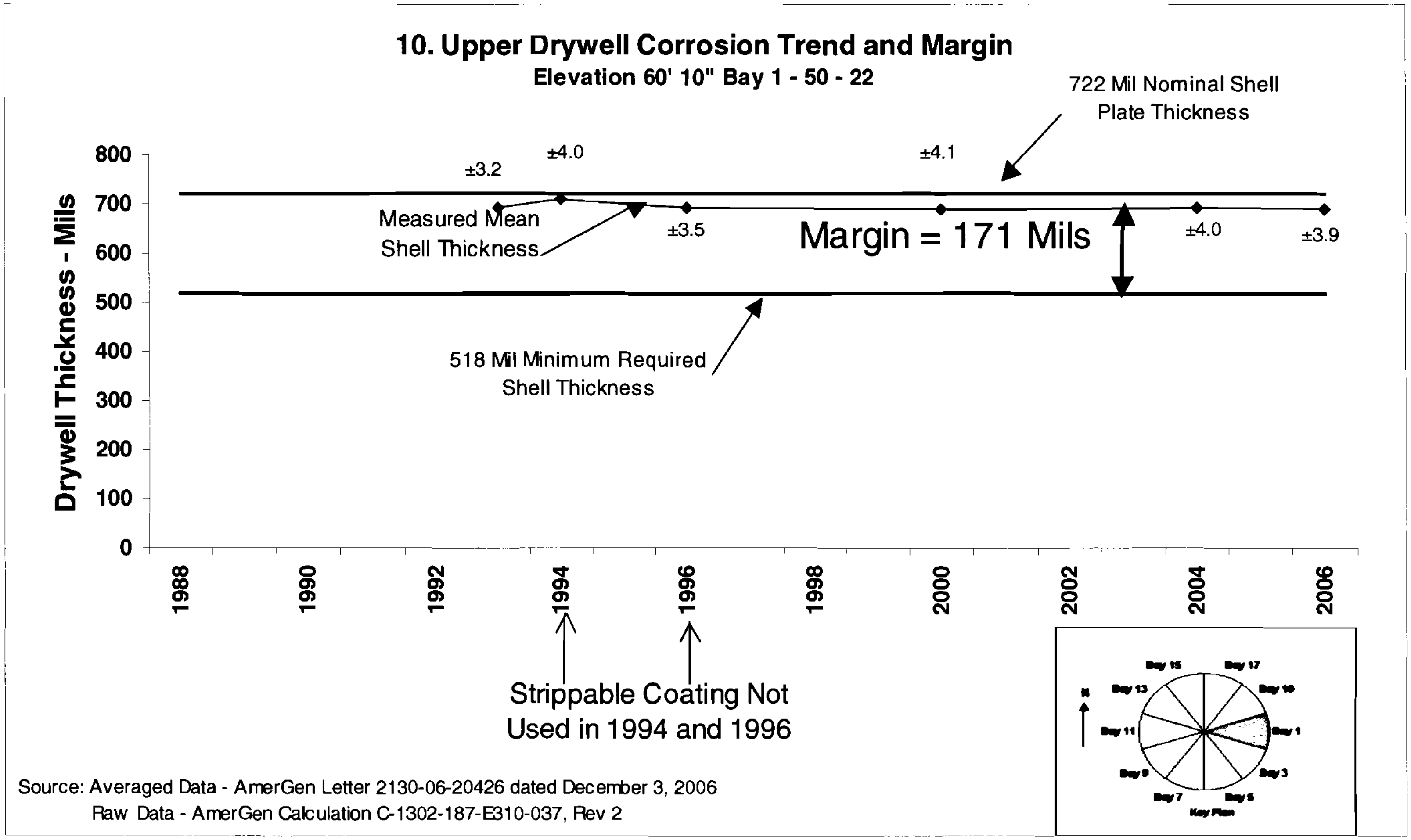

5. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 13 - 31L
770 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±8.4
±6.4
±8.0
±6.1
±8.2
±6.9
±6.0
±8.4
Measured Mean Shell Thickness
Margin = 137 Mils
541 Mil Minimum Required Shell Thickness
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Key Plan

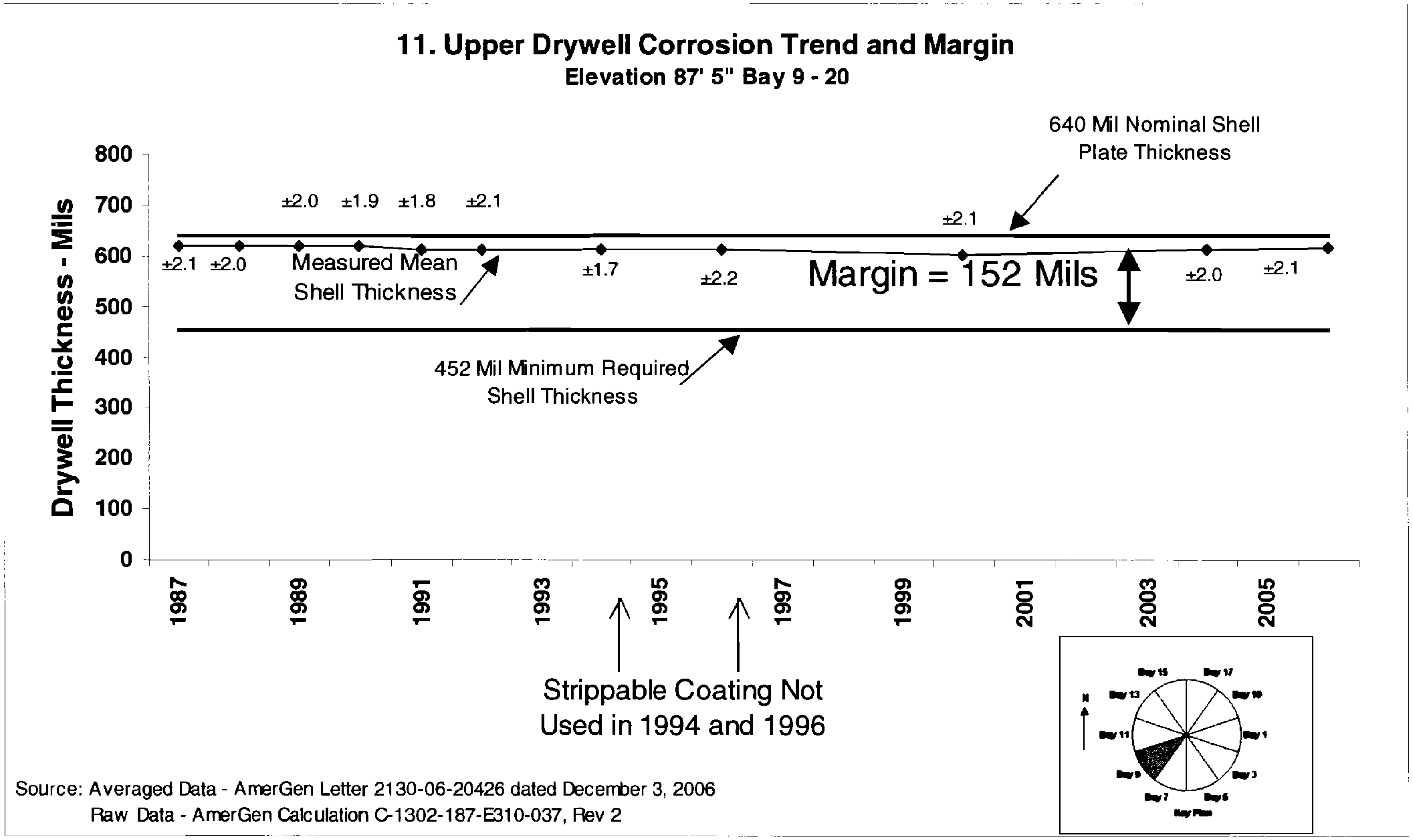

6. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 15 - 23H
770 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
Measured Mean Shell Thickness
Margin = 216 Mils
541 Mil Minimum Required Shell Thickness
±1.2 ±1.3 ±1.3 ±1.0 ±1.4 ±1.1 ±1.3 ±1.2
Strippable Coating Not Used in 1994 and 1996
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

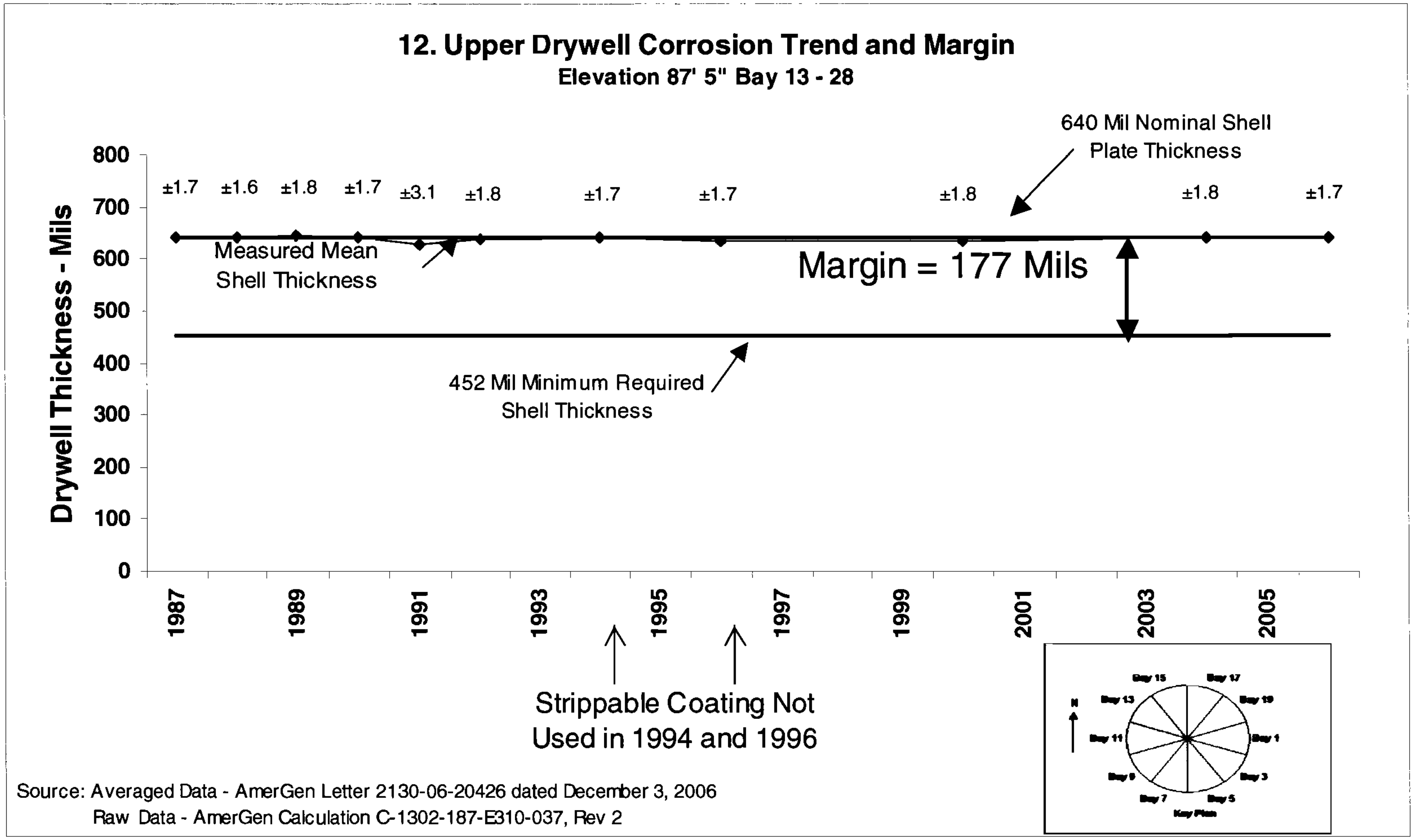

7. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 15 - 23L
770 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±3.7
±4.2
±5.3
±4.3
±4.9
±3.6
±3.3
±3.1
Measured Mean Shell Thickness
Margin = 183 Mils
541 Mil Minimum Required Shell Thickness
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Strippable Coating Not Used in 1994 and
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan

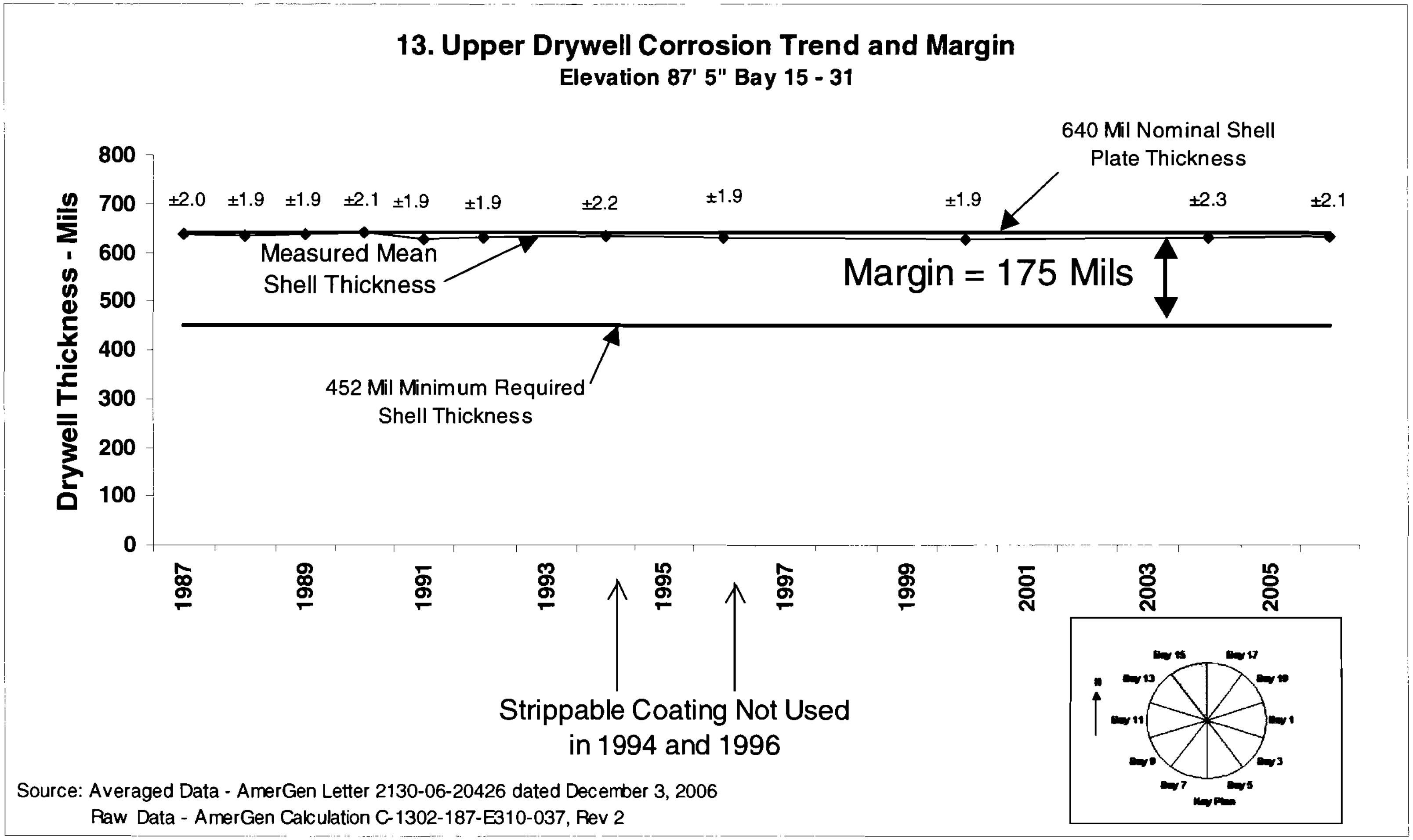

8. Upper Drywell Corrosion Trend and Margin
Elevation 51' 10" Bay 13 - 32H
722 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±0.7
±0.9
±0.9
±0.8
±1.2
±0.8
±0.7
±0.6
Measured Mean Shell Thickness
Margin = 195 Mils
518 Mil Minimum Required Shell Thickness
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Strippable Coating Not
Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Bay 15
Bay 17
Bay 13
Bay 19
N
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan


9. Upper Drywell Corrosion Trend and Margin
Elevation 51' 10" Bay 13 - 32L
722 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±4.5
±4.5
±6.0
±4.5
±4.9
±5.2
±3.6
±3.8
Measured Mean Shell Thickness
Margin = 158 Mils
518 Mil Minimum Required Shell Thickness
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2


10. Upper Drywell Corrosion Trend and Margin
Elevation 60' 10" Bay 1 - 50 - 22
722 Mil Nominal Shell Plate Thickness
±3.2
±4.0
±4.1
Measured Mean Shell Thickness
±3.5
Margin = 171 Mils
±4.0
±3.9
518 Mil Minimum Required Shell Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

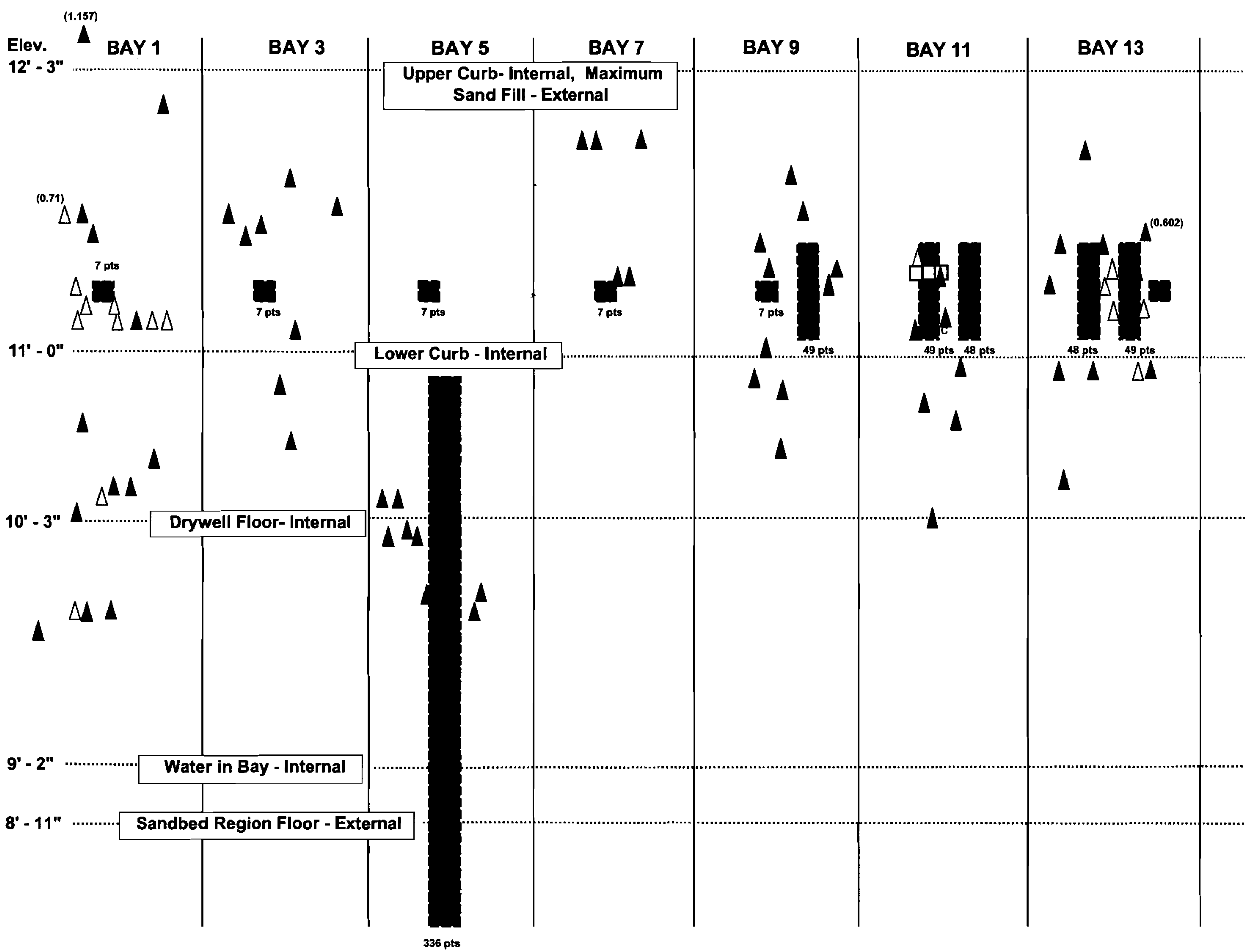

11. Upper Drywell Corrosion Trend and Margin
Elevation 87' 5" Bay 9 - 20
640 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 152 Mils
452 Mil Minimum Required Shell Thickness
Drywell Thickness - Mils
±2.1 ±2.0 ±2.0 ±1.9 ±1.8 ±2.1 ±1.7 ±2.2 ±2.1 ±2.0 ±2.1
800 700 600 500 400 300 200 100 0
1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2


12. Upper Drywell Corrosion Trend and Margin
Elevation 87' 5" Bay 13 - 28
640 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±1.7 ±1.6 ±1.8 ±1.7 ±3.1 ±1.8 ±1.7 ±1.7 ±1.8 ±1.8 ±1.7
Measured Mean Shell Thickness
Margin = 177 Mils
452 Mil Minimum Required Shell Thickness
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2



13. Upper Drywell Corrosion Trend and Margin
Elevation 87' 5" Bay 15 - 31
640 Mil Nominal Shell Plate Thickness
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
±2.0
±1.9
±1.9
±2.1
±1.9
±1.9
±2.2
±1.9
±1.9
±2.3
±2.1
Measured Mean Shell Thickness
Margin = 175 Mils
452 Mil Minimum Required Shell Thickness
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
Strippable Coating Not Used in 1994 and 1996
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

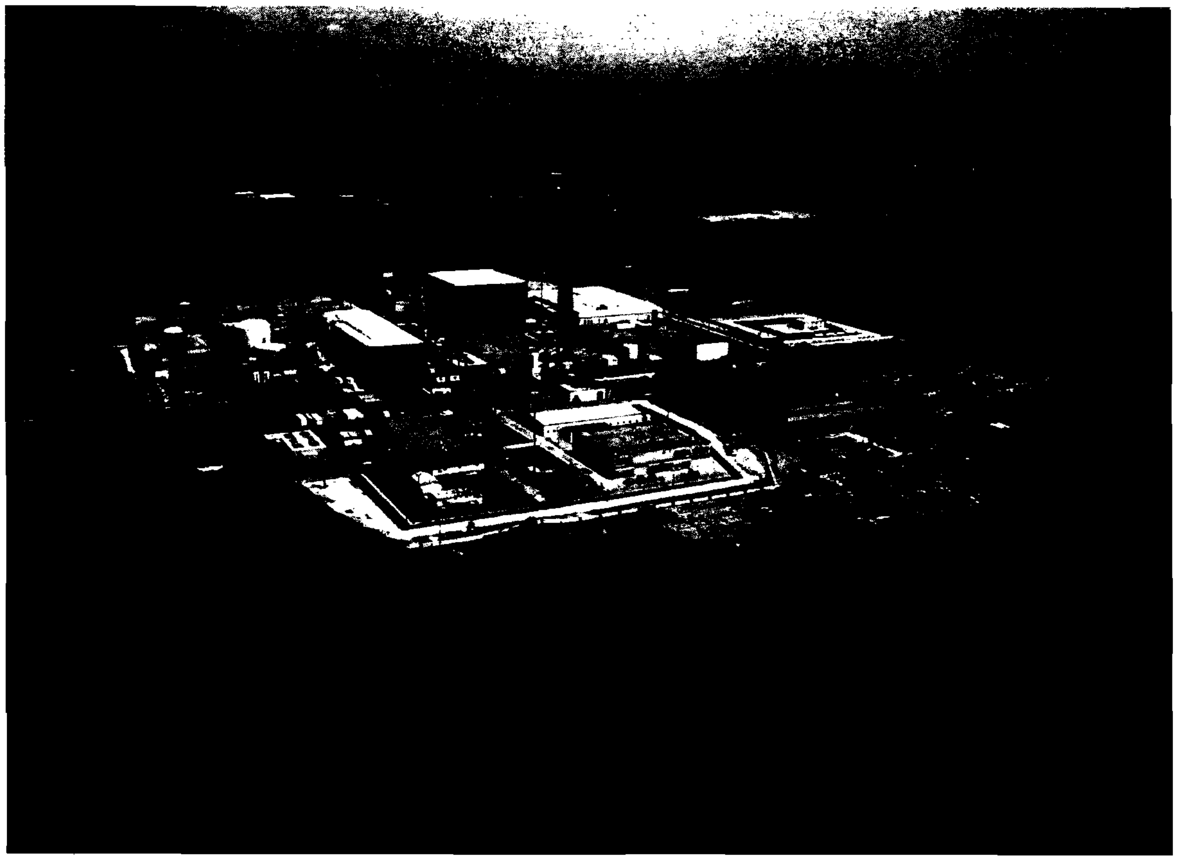
Green = UT Measurements > 736 Mils
Yellow = UT Measurements Between 636 and 736 Mils
Red = UT Measurements Between 536 and 636 Mils



Oyster Creek Generating Station

License Renewal

ACRS Presentation - January 18, 2007



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Presentation

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Verification of Elimination of Water Leakage Into Sand Bed Region						
1) Cavity Liner – Apply Tape & Strippable Coating	Yes	Yes	Yes	Yes	Yes	Y
2) Cavity Drain – Confirm Drain is Clear	Yes	Yes	Yes	Yes	Yes	Y
3) Cavity Drain – Monitor Flow Rate	Daily	Daily	Daily	Daily	Daily	Da
4) Sand Bed Drains – Confirm No Water	Daily	Daily	Daily	Daily	Daily	Da
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 greate Drywell 13 Locations	
2) UT Inspections – Upper Drywell 13 Locations Inside Drywell @ 87'-5", 60'-10", 51'-10", 50'-2"	100%		100%		100%	
3) UT Inspections – Drywell Transition Areas Inside Drywell @ 23'-6"	2 Areas	2 Areas	2 Areas	2 Areas	If corrosion is greate Drywell 13 Location	
Sand Bed Region Shell Monitoring						
1) UT Inspections – Sand Bed 19 Locations Inside Drywell @ 11'-3"	100%		100%	Subsequent UT inspe		
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	
3) UT Inspections – Sand Bed 106 External Locally Thinned Locations	10 Bays	10 Bays	Bay 1 & 13	2 Bays	2 Bays	2
4) VT Inspection of Drywell Shell in Trench Locations Inside Drywell	100%	100%	100%	VT Inspections will continue each ou		
5) UT Inspection of Drywell Shell in Trench Locations Inside Drywell	626 Points	626 Points	626 Points	UT Inspections will continue each ou		
6) Inspection for Water in Trenches	Yes	Yes	Yes	If water is not observed in trenches f		
General Monitoring						
1) Structures Monitoring – Visual Inspection of Concrete Floor, Trough & Shell Inside Drywell	Yes	Yes	Yes	Yes	Yes	
2) Structures Monitoring – Visual Inspection of Sump	Yes		Yes		Yes	
3) Appendix J Test – Pressure Test and Visual Inspection of Accessible Int. and Ext. Shell Surfaces			Test			
4) Drywell Service Level 1 Coating Inspection Inside Drywell	Yes		Yes		Yes	
5) Structures Monitoring – Visual Inspection of Moisture Barrier between Drywell Shell						

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Oyster Creek License Renewal Presentation to ACRS Subcommittee

January 18, 2007

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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

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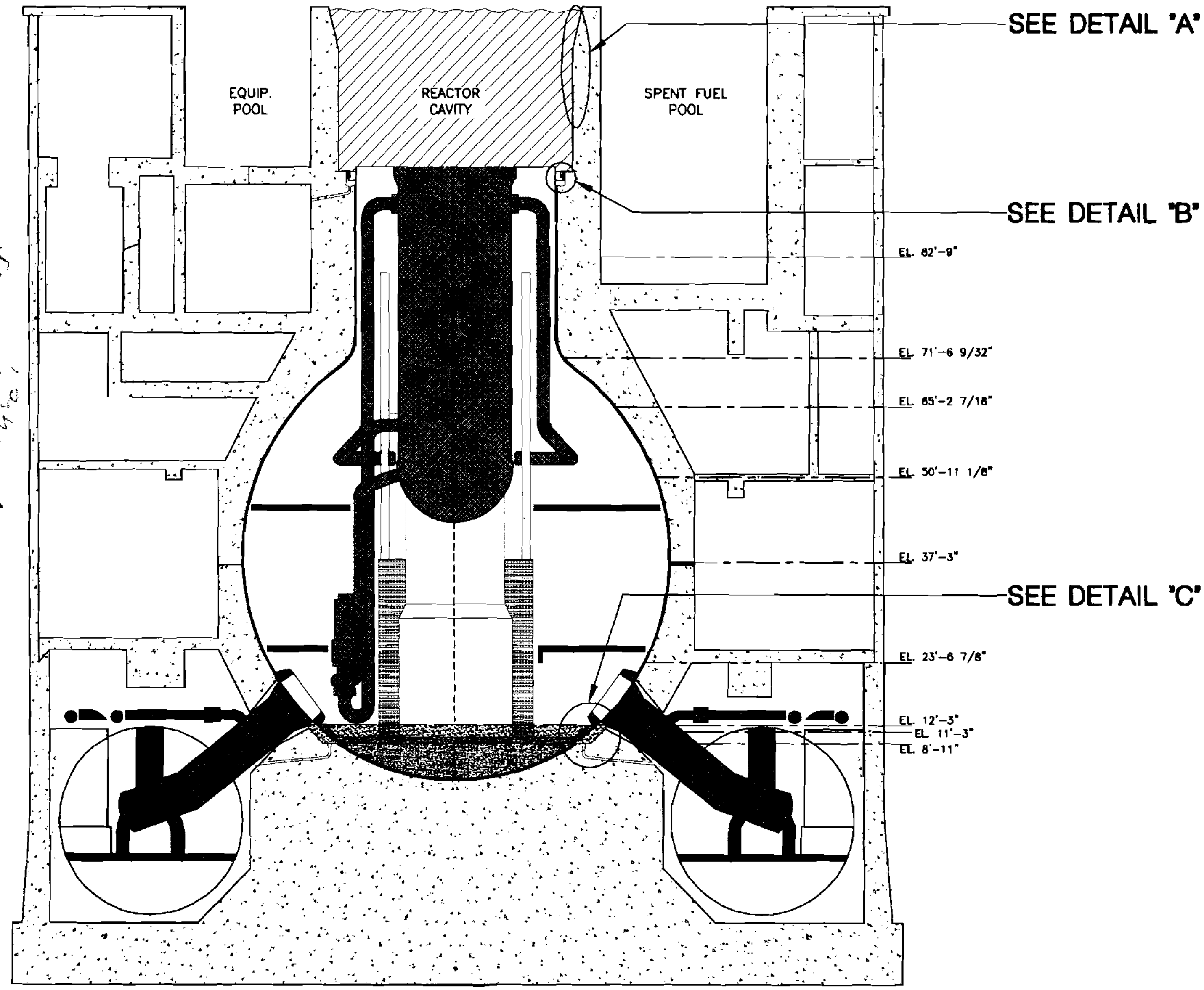
Dr. Wallis asked about 2# ground line in GE Analyses will be answered later in presentation



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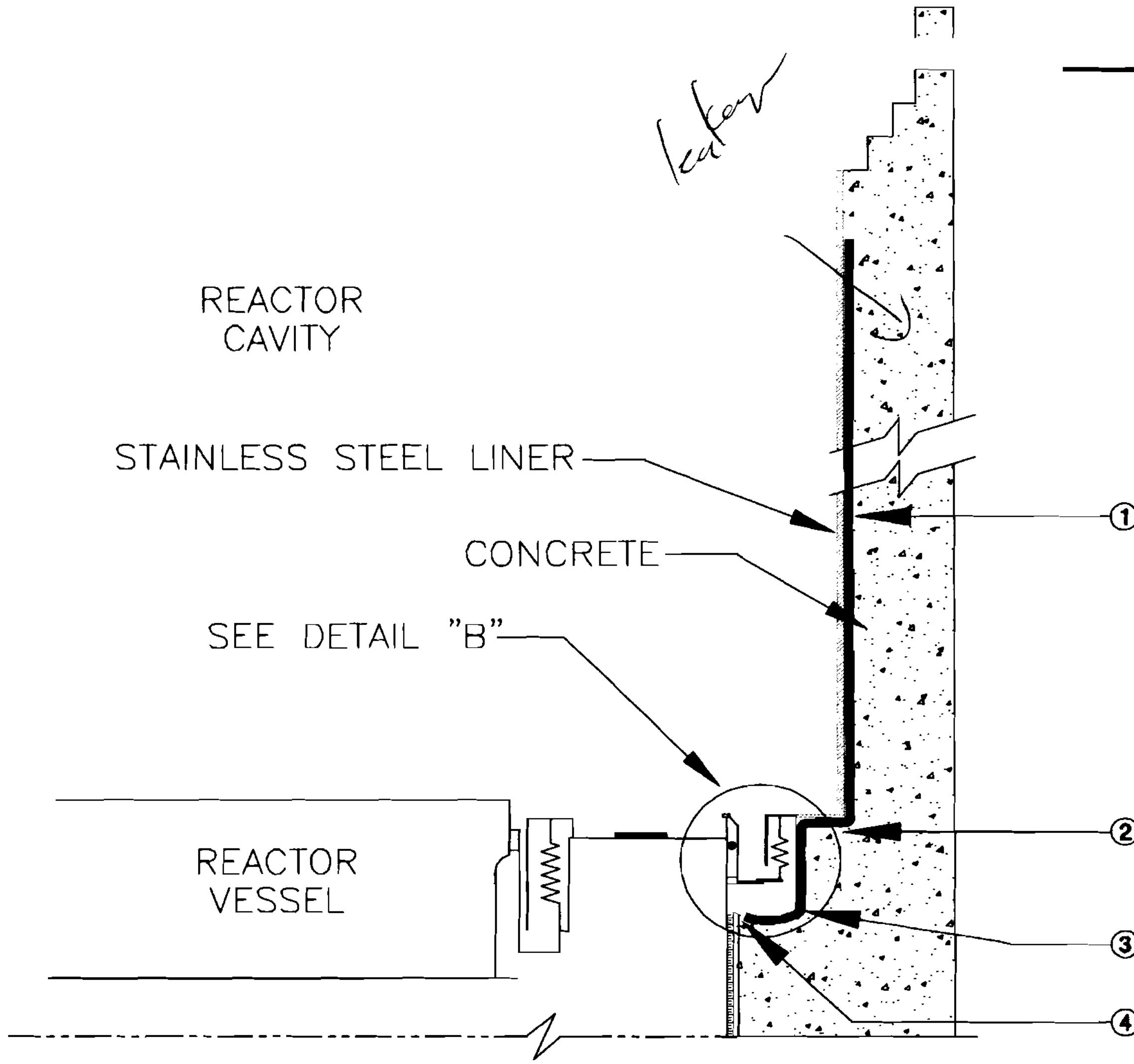

DRYWELL AND REACTOR CAVITY SECTION
DETAIL "A"

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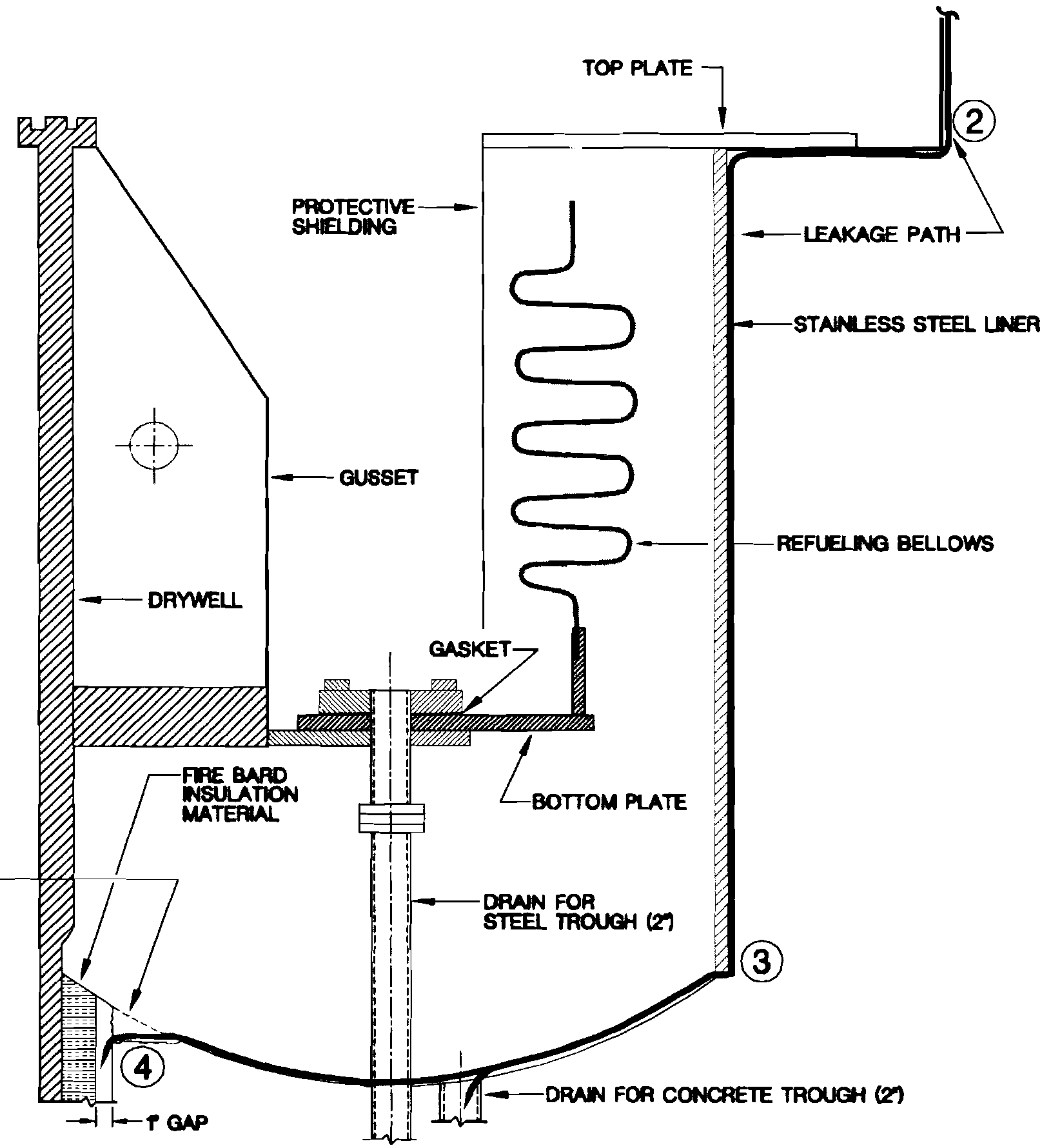
DRYWELL TO REACTOR CAVITY SEAL DETAIL
DETAIL "B"



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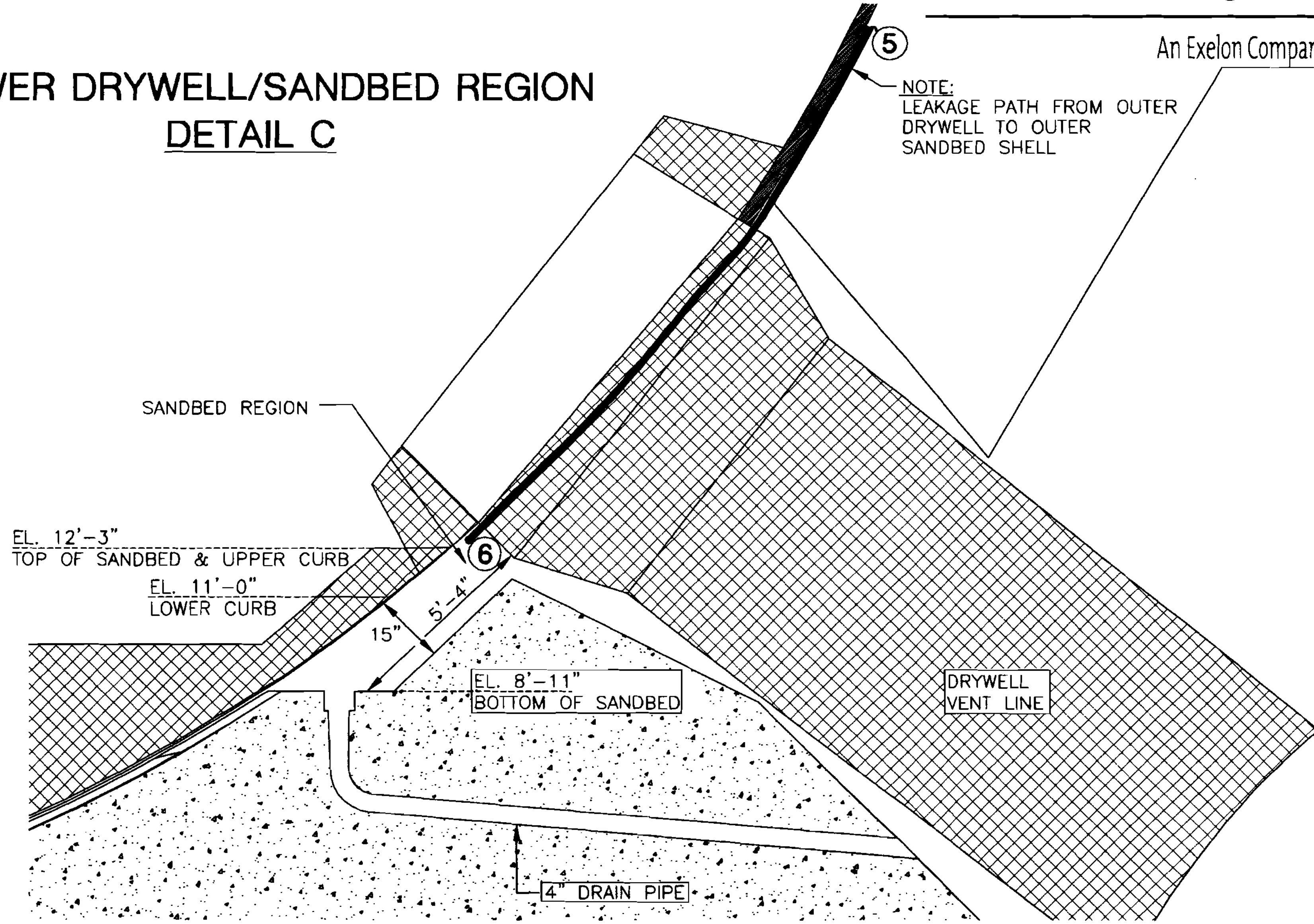
LOWER DRYWELL/SANDBED REGION
DETAIL C



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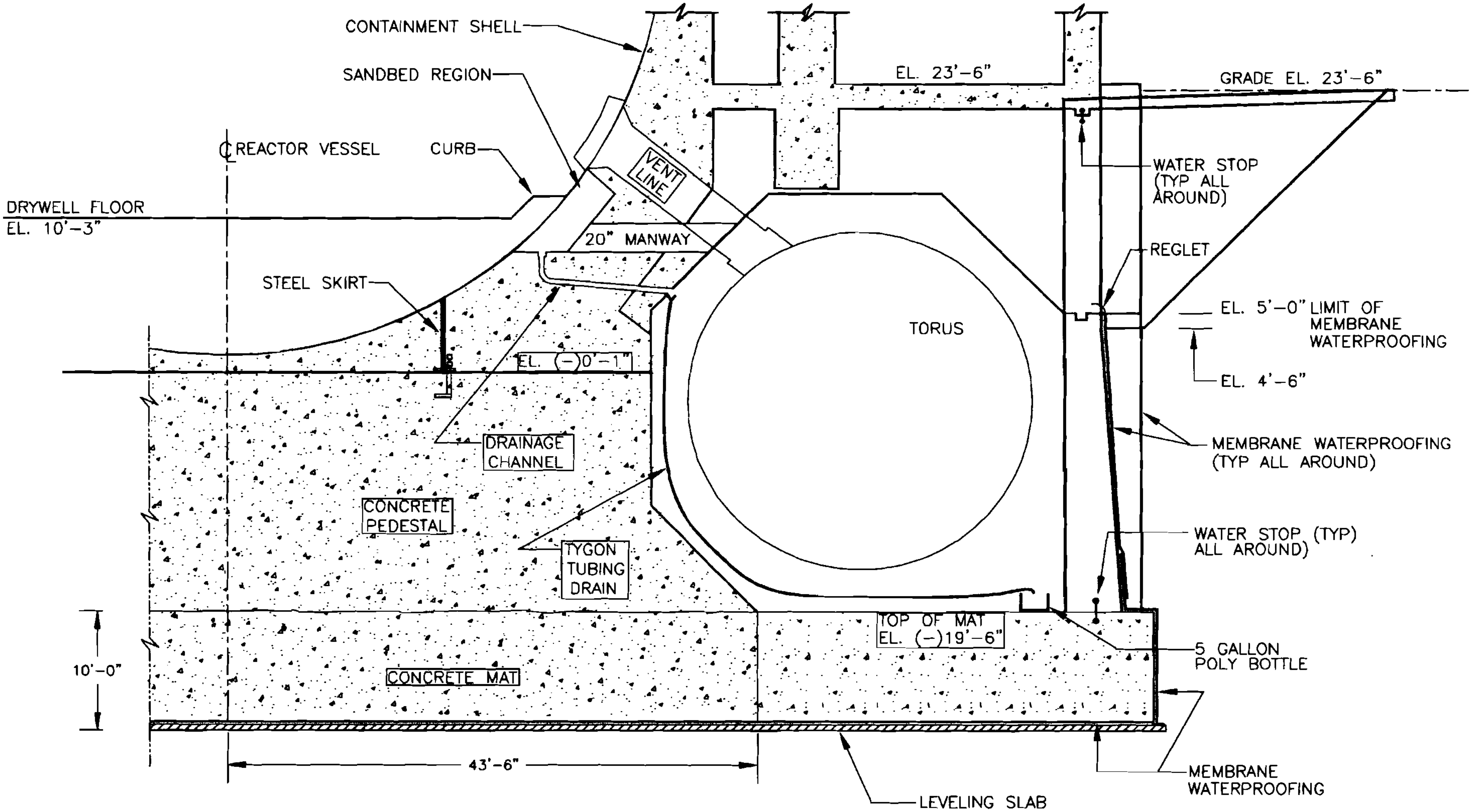
REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE



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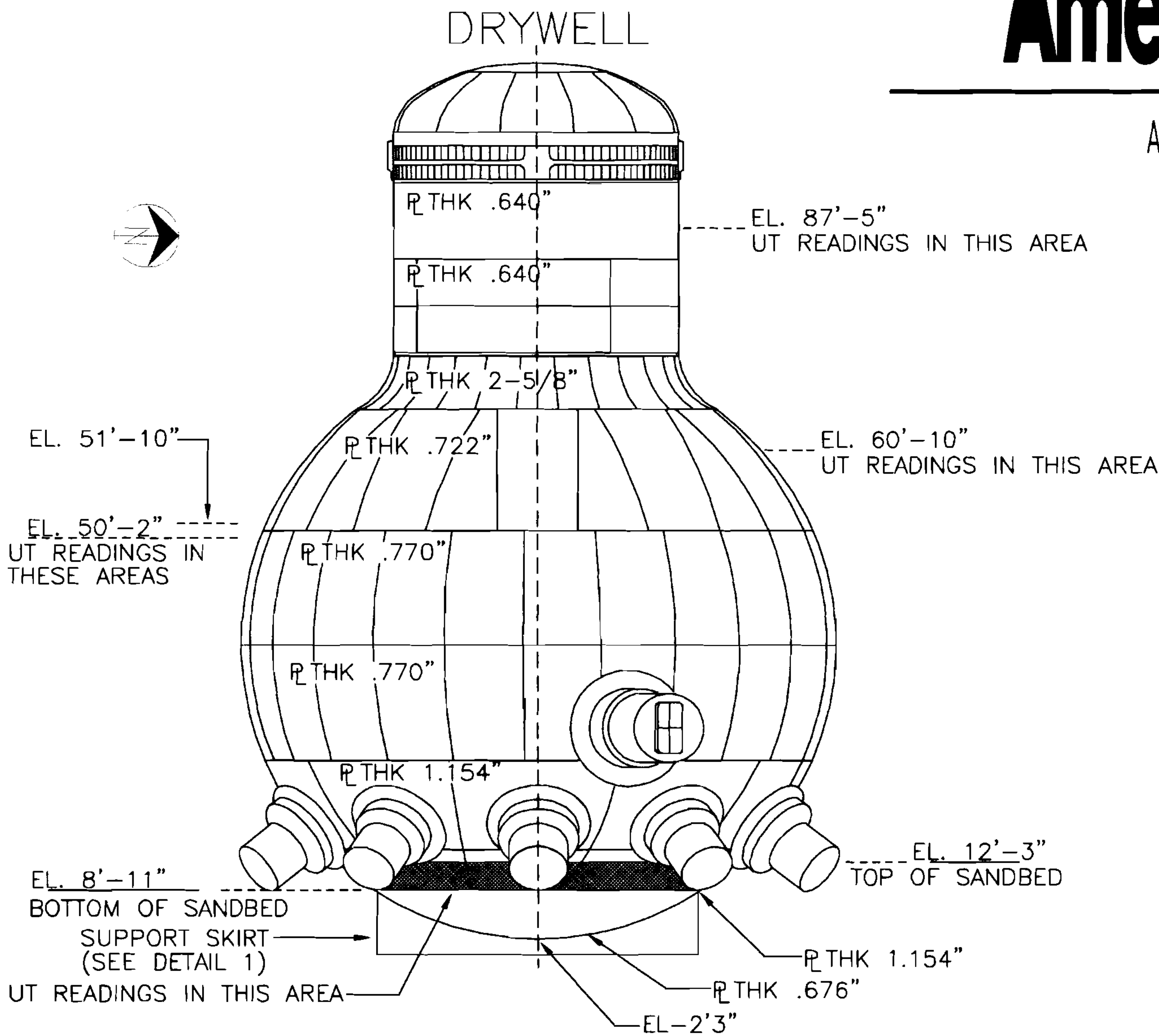

[illegible]
How much rust was taken away? → Amer will get Pete Tamburello

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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
  - oated the drywell shell with epoxy in the sand d 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)

Question he said => one measurement is much thinner than other why isn't it included

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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
[illegible]	770	678	541	137
[illegible]	1154	1160	629	531
[illegible]	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.

Finite Element Models Used

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- 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

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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

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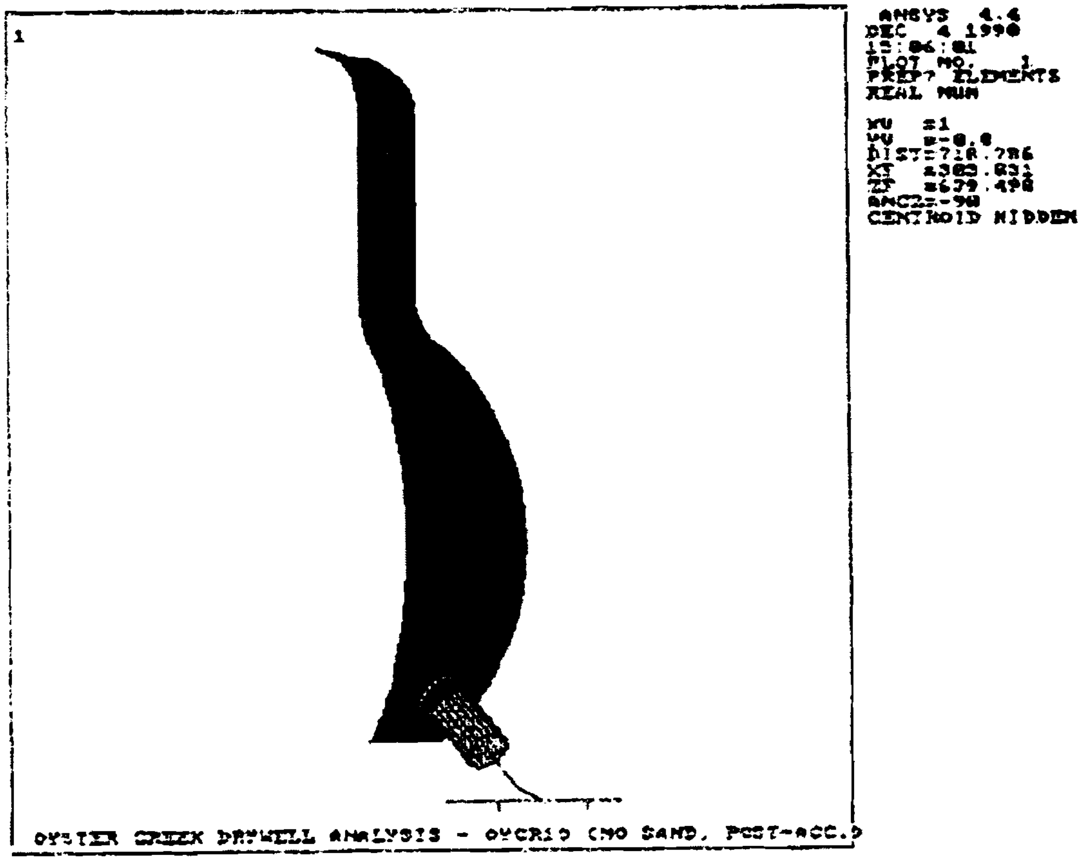

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Applied Loads

- 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)

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Seismic Load Definition

- 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)

Follow up w/ [illegible] on what is really [illegible]

Dear Ben [illegible] requirement [illegible] what is valid [illegible]?

Dr. Wallis asked?

This add 600 psi to stress [illegible]

[illegible] margin

Said properties used in calculation

But different Mechanical properties were considered and are available

extra [illegible] conservatism

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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.

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Buckling Analysis Details

- 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

Graham
When data came from sand bed
Any stress in general area/section
however area would not affect calculation results

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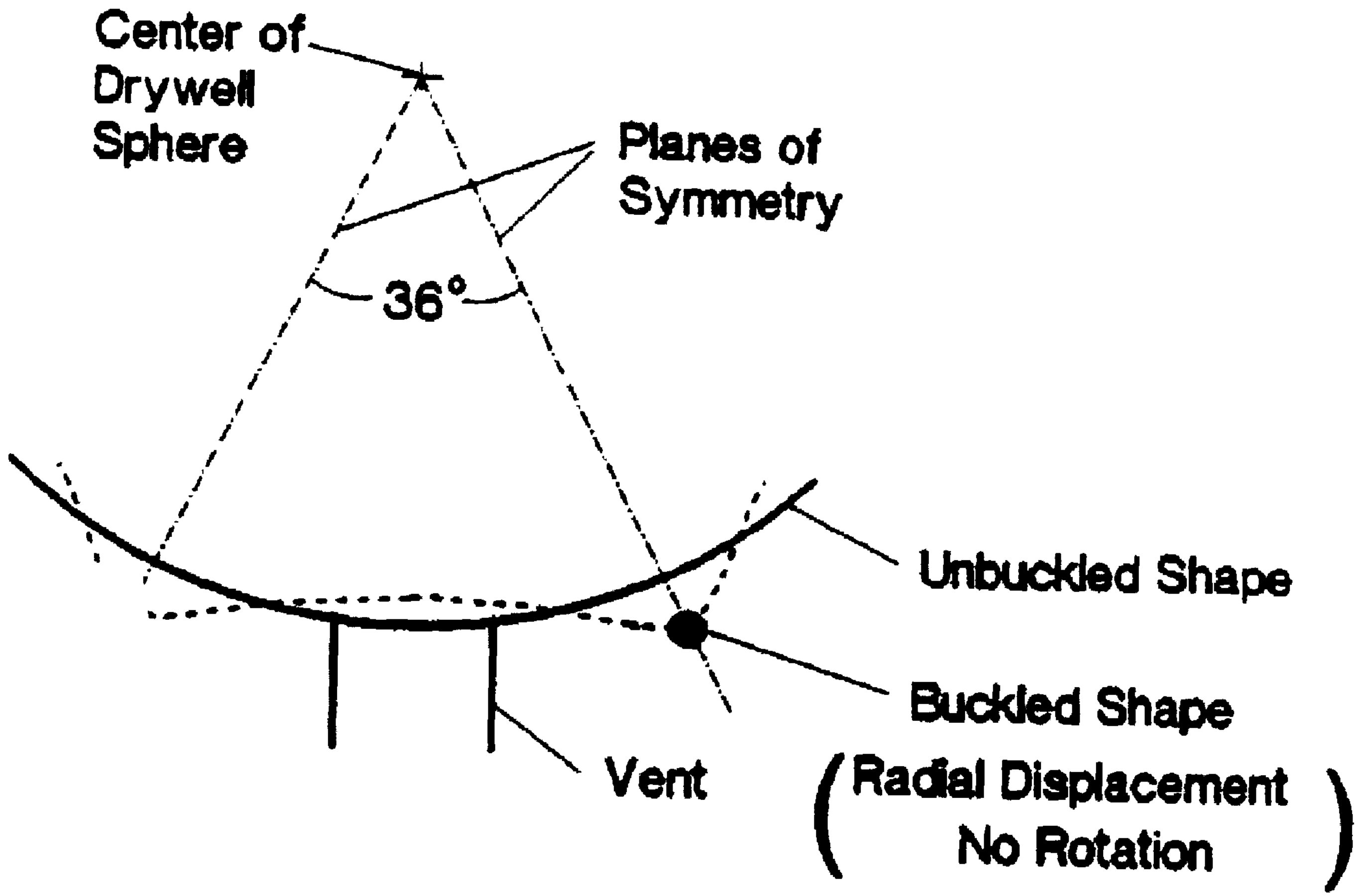
Buckling Analysis Details

Many Questions



tric Buckling of Drywell

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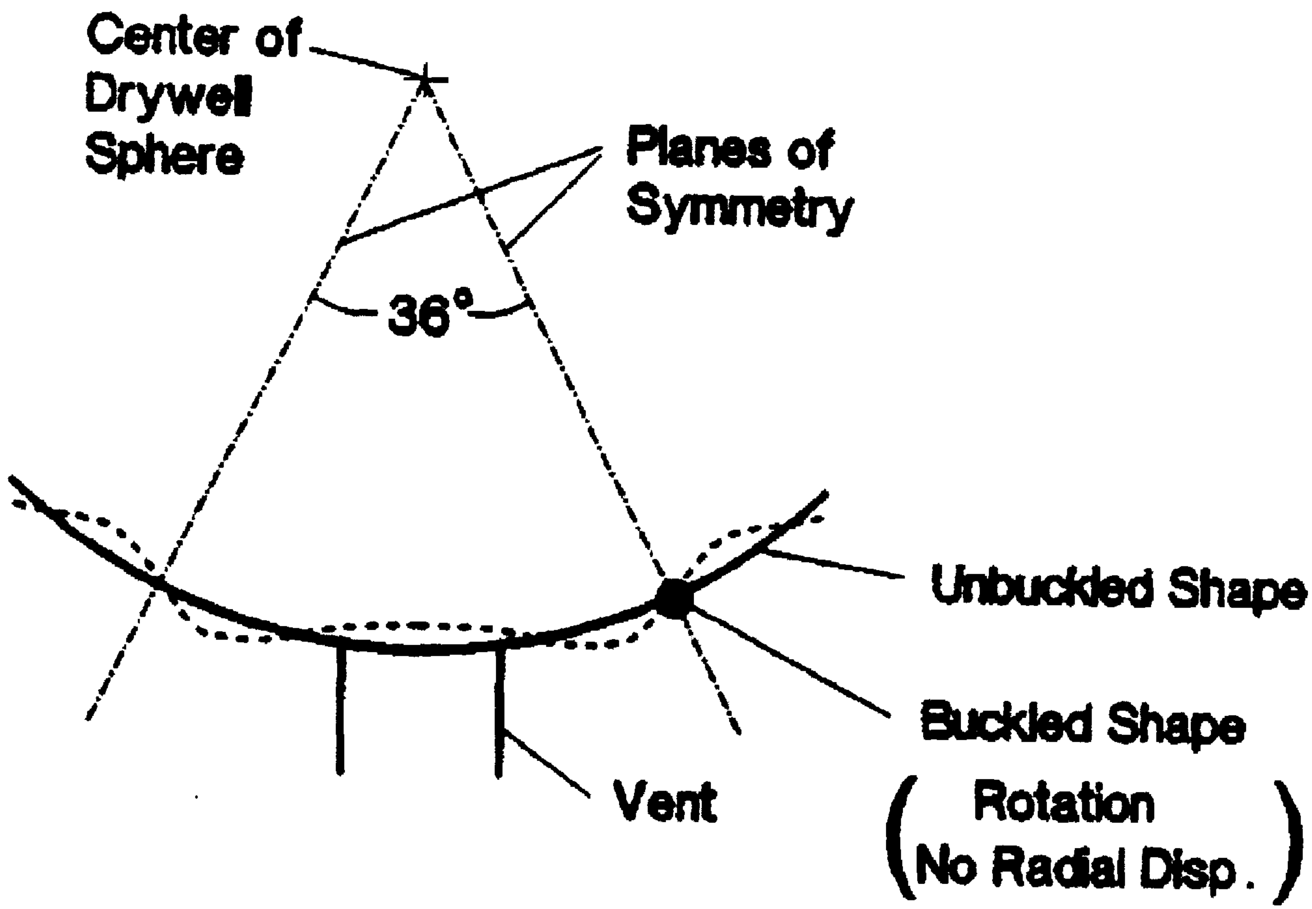
Buckling Analysis Details



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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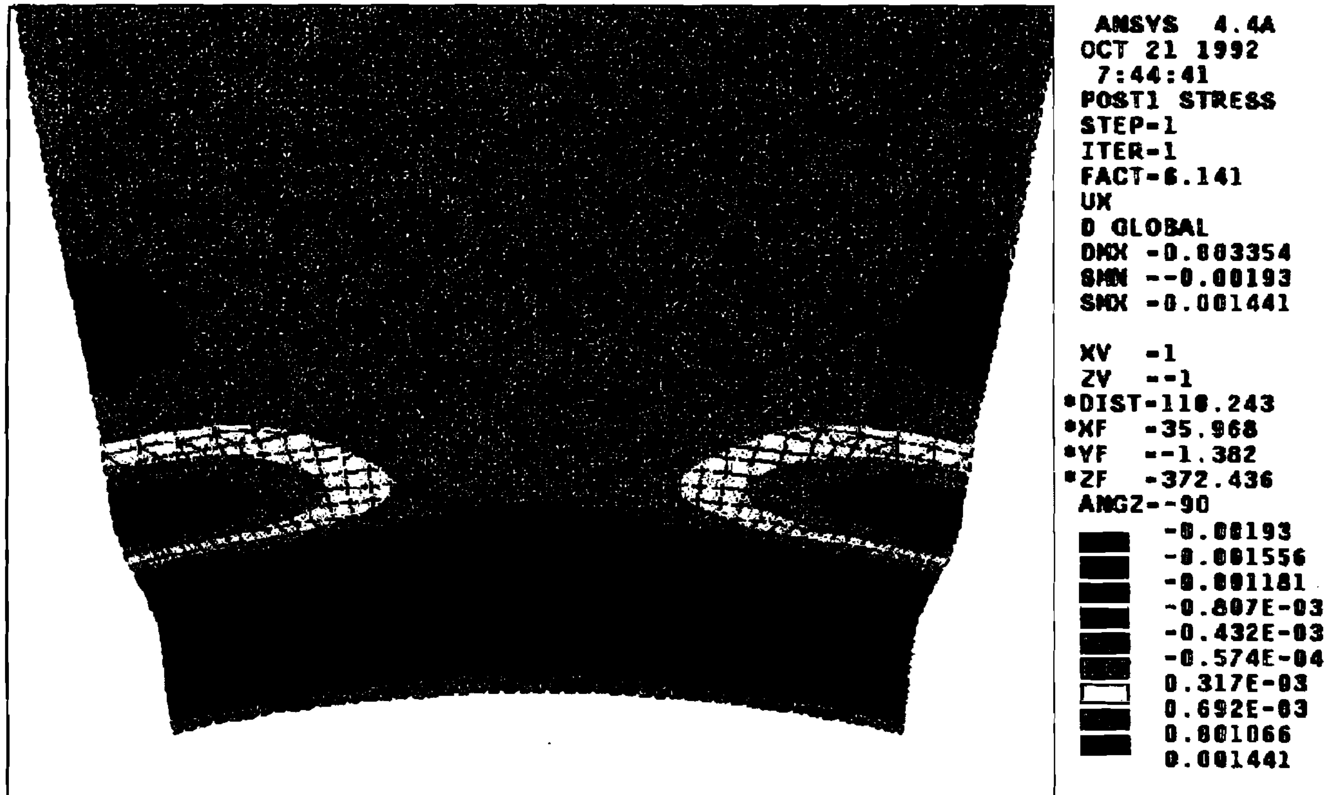

Figure 3-18 Sym-Sym Buckling Mode Shape - Refueling Case

OYSTER CREEK DRYWELL ANALYSIS - OCRFREF SYM-SYM (NO SAND, REFUELING)

Buckling Analysis Details

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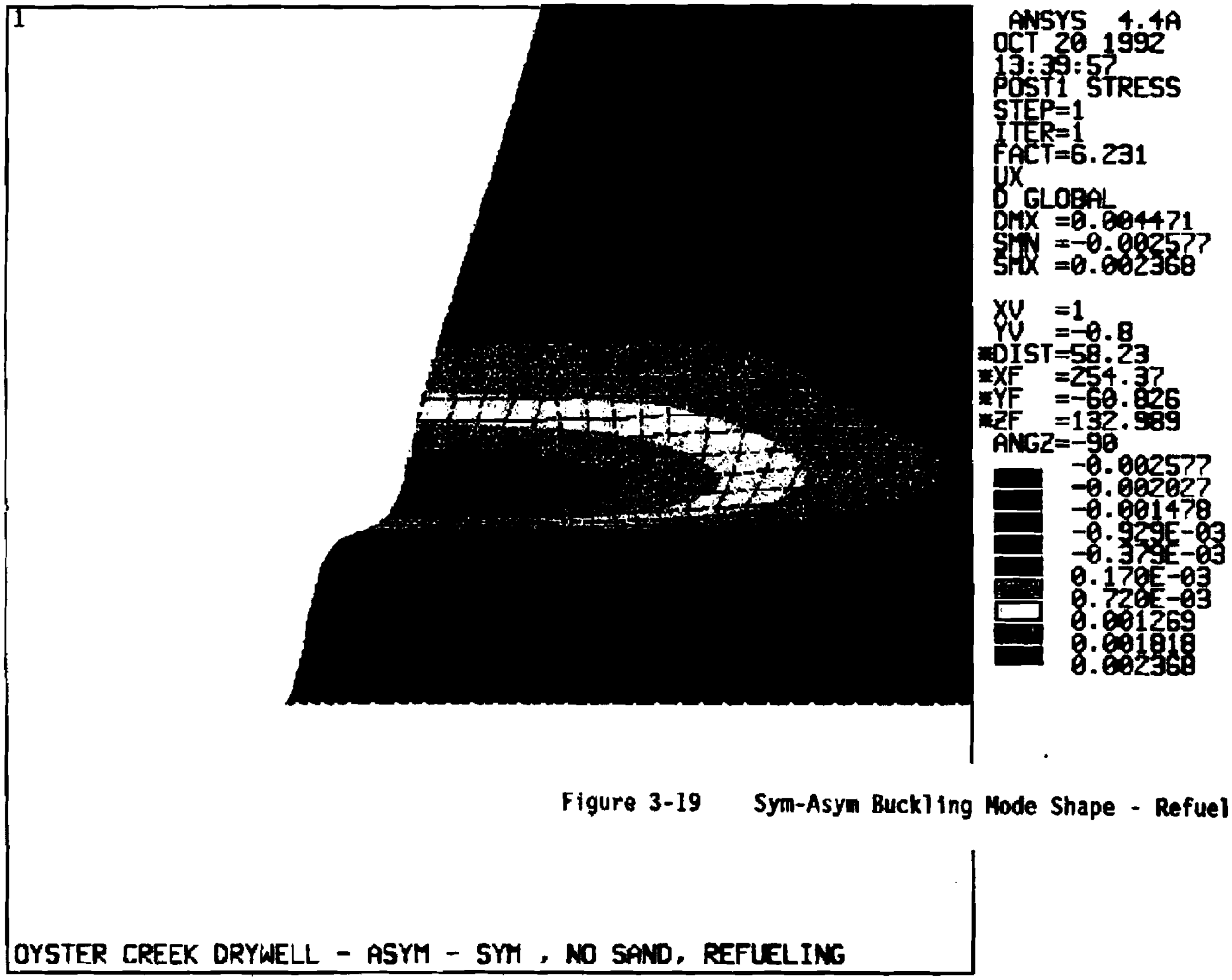

Figure 3-19 Sym-Asym Buckling Mode Shape - Refueling Case

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Buckling Analysis Details

Summary of Buckling Analysis Results – Refueling Case

Parameter	Value
Theoretical Elastic Instability Stress, σ_{ie} (ksi)	46.59
Capacity Reduction Factor, α_i	0.207
Circumferential Stress, σ_c (ksi)	4.51
Equivalent Pressure, p (psi)	15.81
"X" Parameter	0.087
ΔC	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, η_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, σ_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

Sam – what thickness does affect the buckling

- 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.
- drywell shell thickness will be monitored using 736 mils as ptance criteria for the minimum required general thickness 536 mils as the minimum required local thickness.

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ASME Section VIII Stress Analysis

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ASME Section VIII Stress Analysis Conclusion

- 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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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

(based on 62 psi, 1993)

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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

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Minimum Required Thicknesses Based on 44 psi pressure

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

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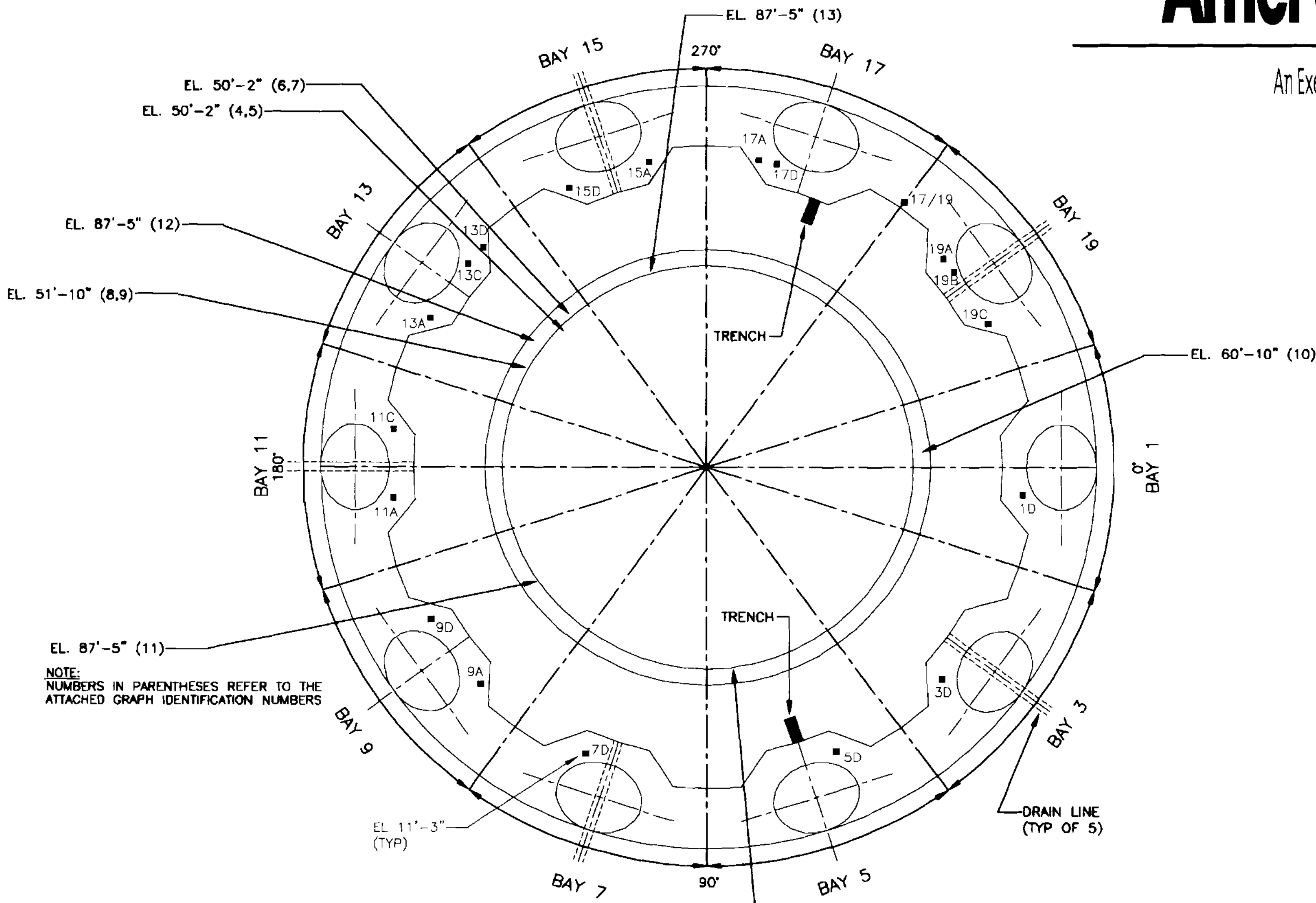

NOTE:
NUMBERS IN PARENTHESES REFER TO THE ATTACHED GRAPH IDENTIFICATION NUMBERS

KEY PLAN

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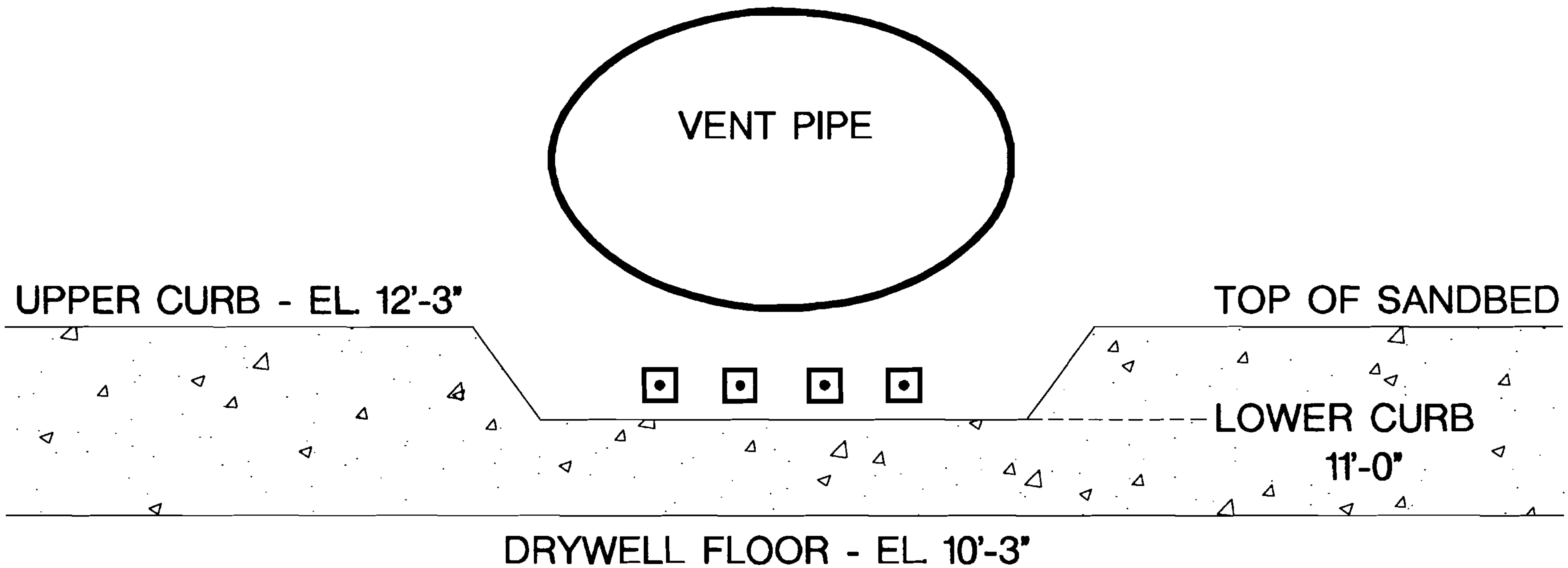
VIEW FROM INSIDE DRYWELL



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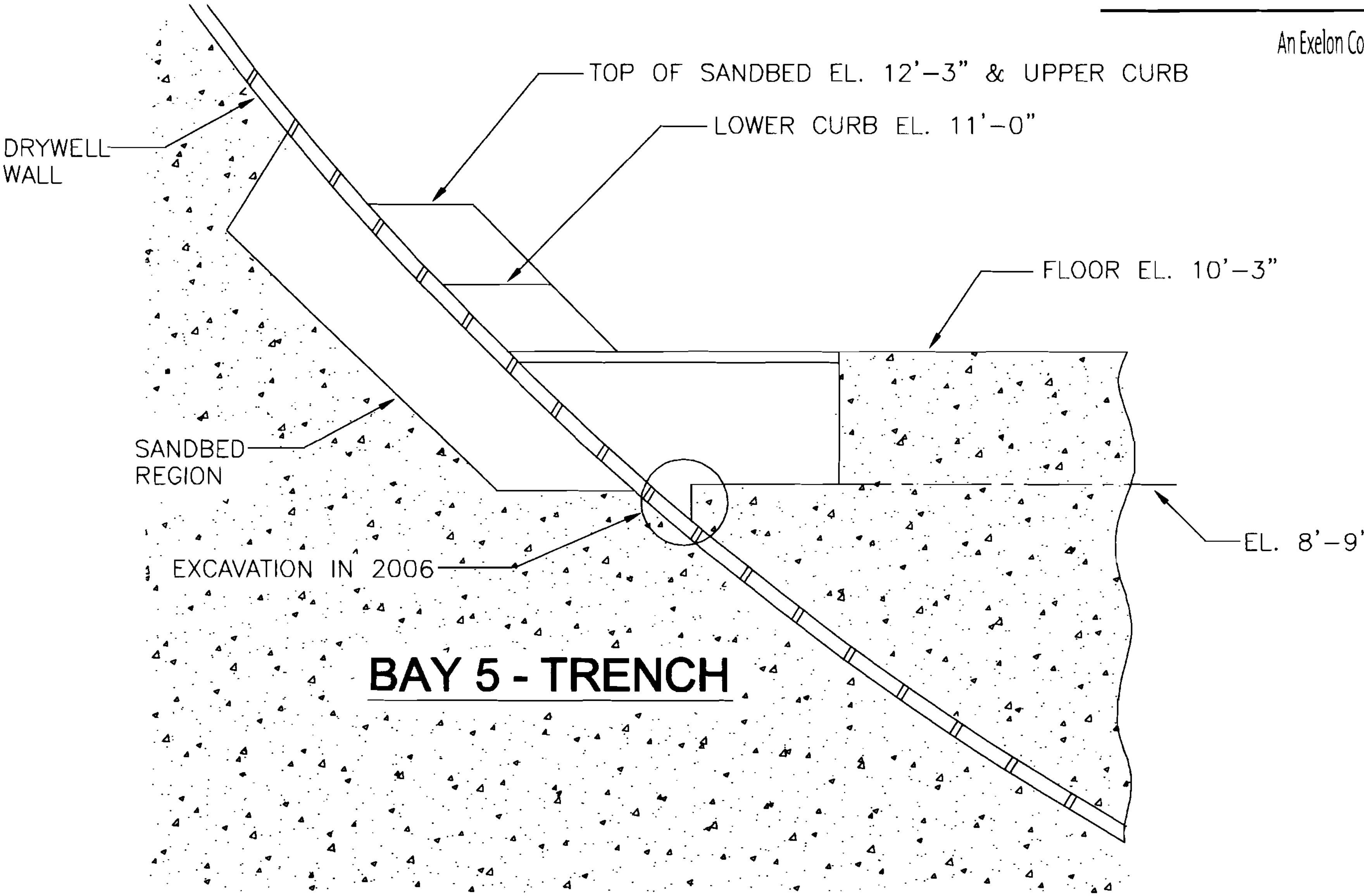

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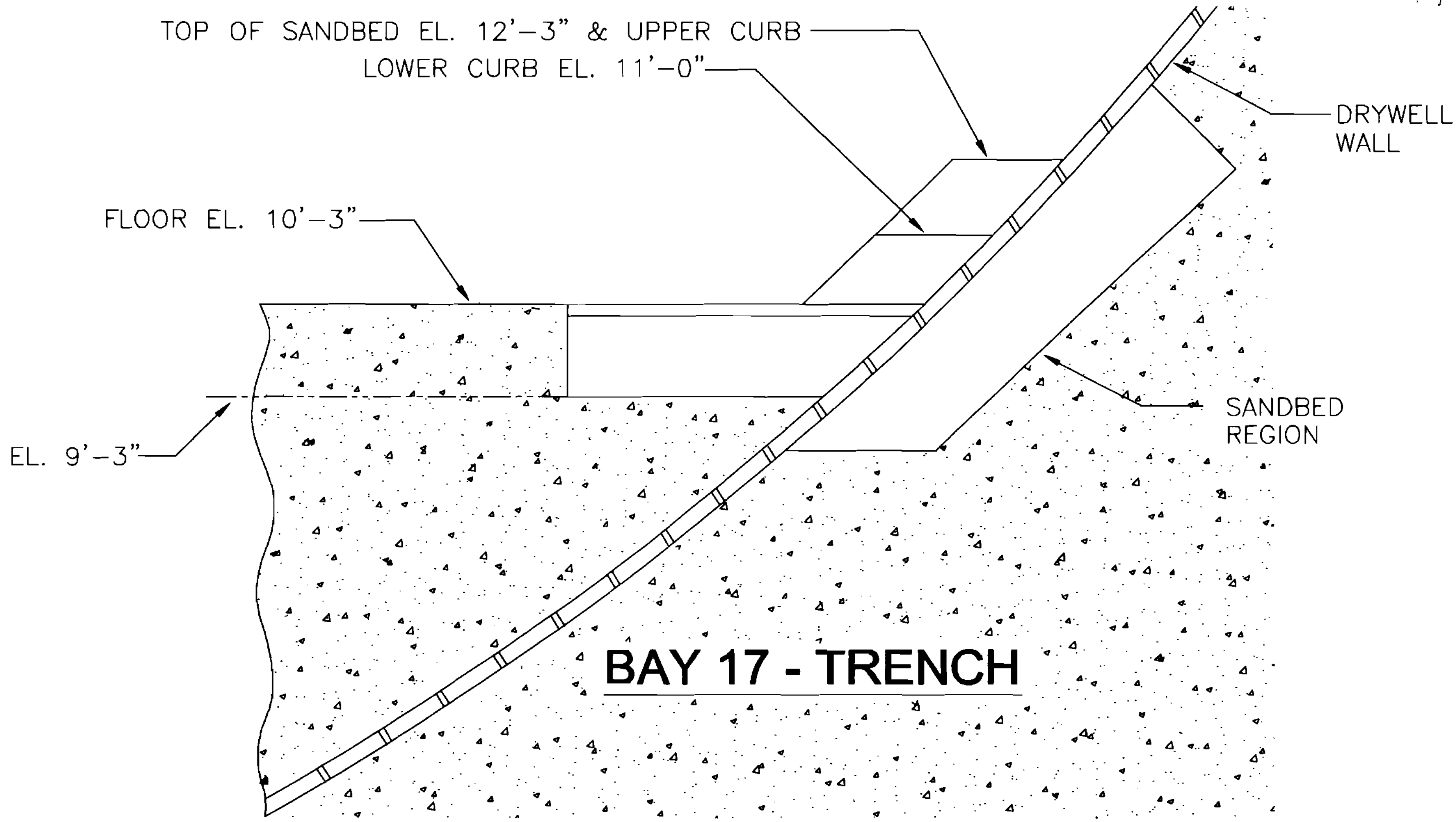

Sand Bed Region Background and History

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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

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- 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

Sand Bed Region 1992

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Drywell
Shell

Corrosion product on drywell vessel

Sand Bed Region 1992

Drywell
Shell

As found condition of floor bed

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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

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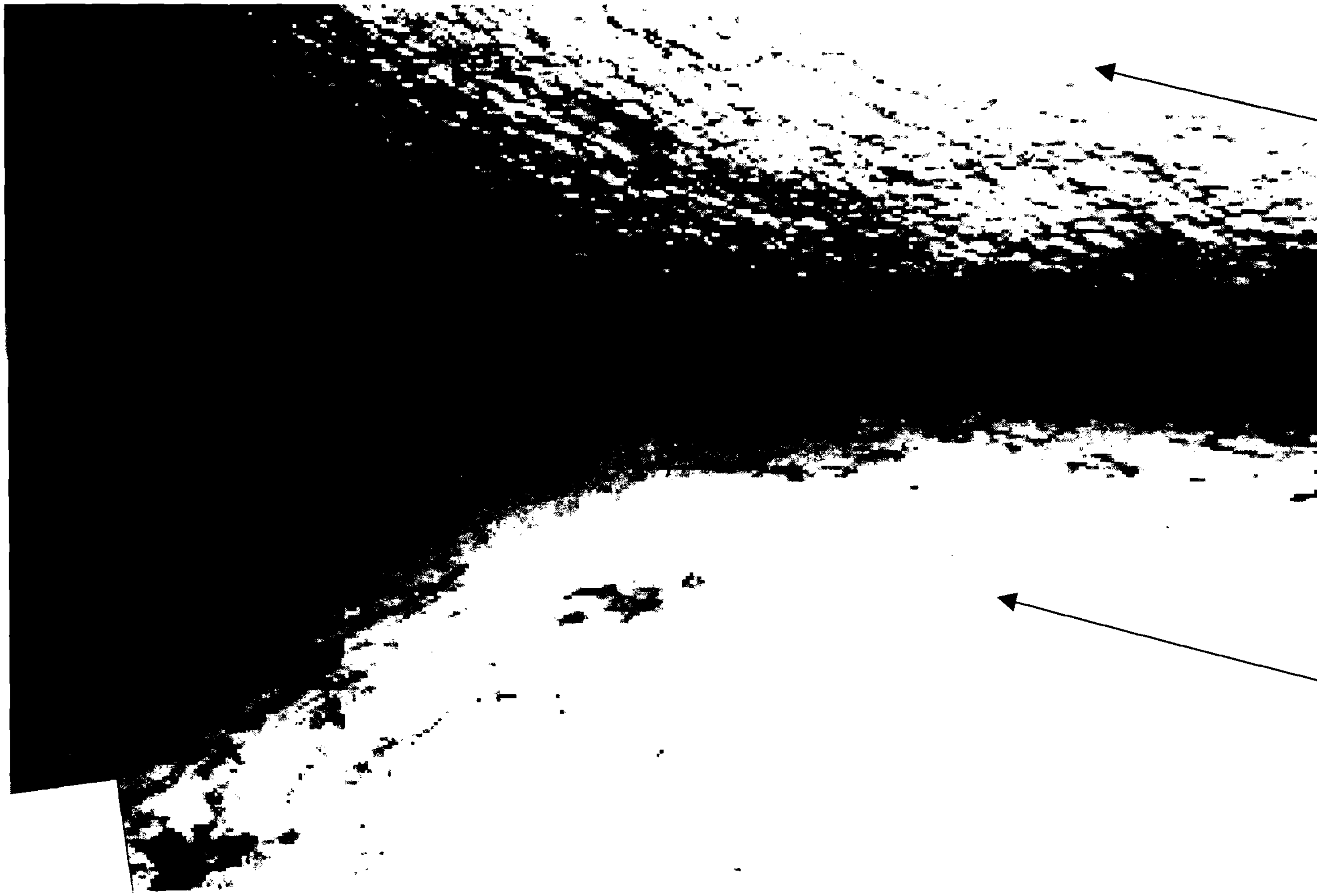
Sand Bed Region 1992



'shed floor, vessel with two top coats – caulking material applied

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Sand Bed Region Background and History

- 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

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Use of Coatings to Prevent Corrosion

Jon R. Cavallo, PE, PCS

Vice President

Corrosion Control Consultants and Labs, Inc.

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Background and History

- 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

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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

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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

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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

2006 UT measurements confirmed that
›sion has been arrested

96 Bad Water
why wasn't it identified?
could have been fixed then
what is done if further
(1) probe in some corrosion
(2) clean sand surface
coat clear
grease to protect surface
(3) Notify NRC w/i 48 hours if not as expected!

UT no longer needed?
only corrosion

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UT Measurements of 6”x6” Grid
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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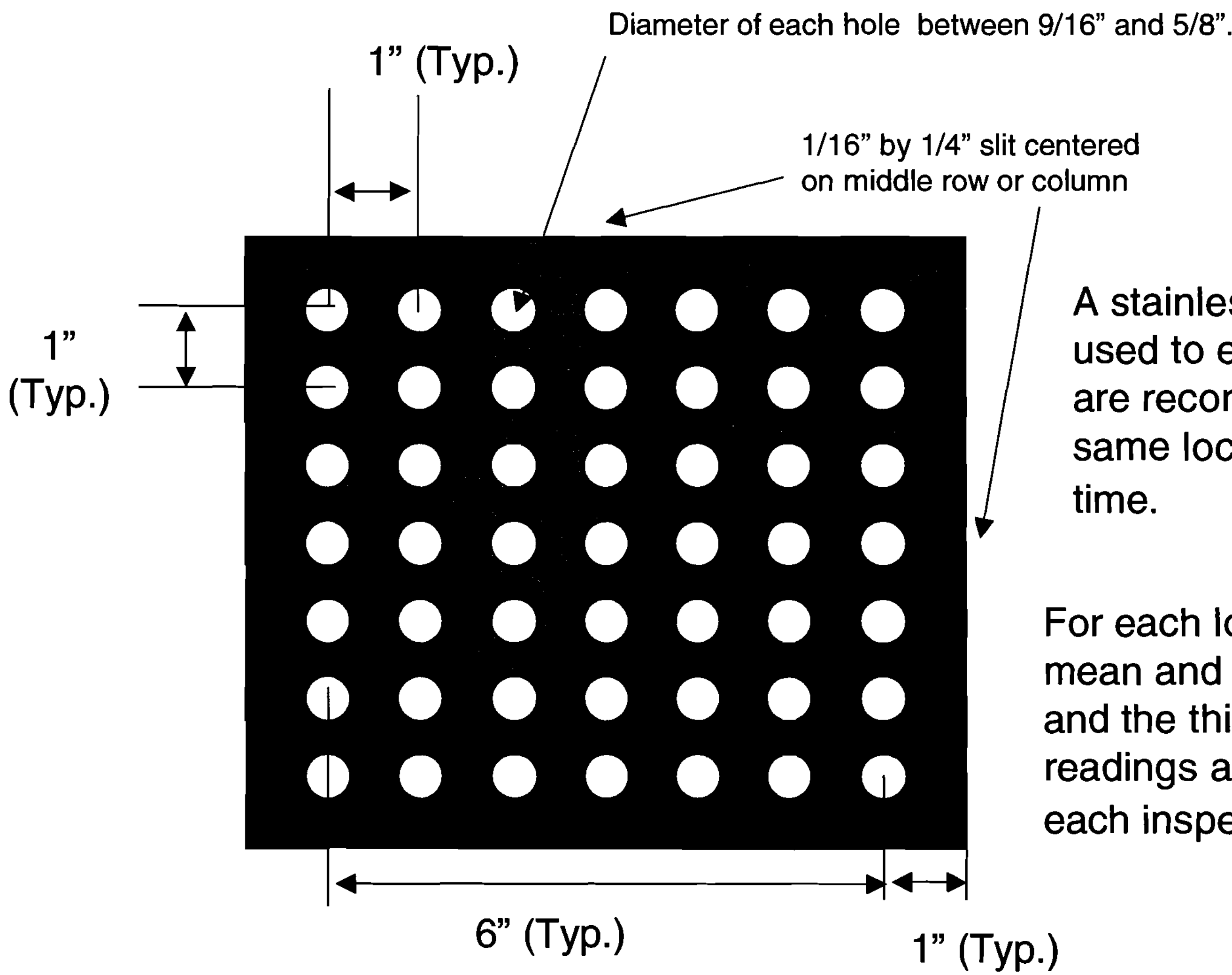
49 UT readings are recorded over a 6" by 6" area.



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

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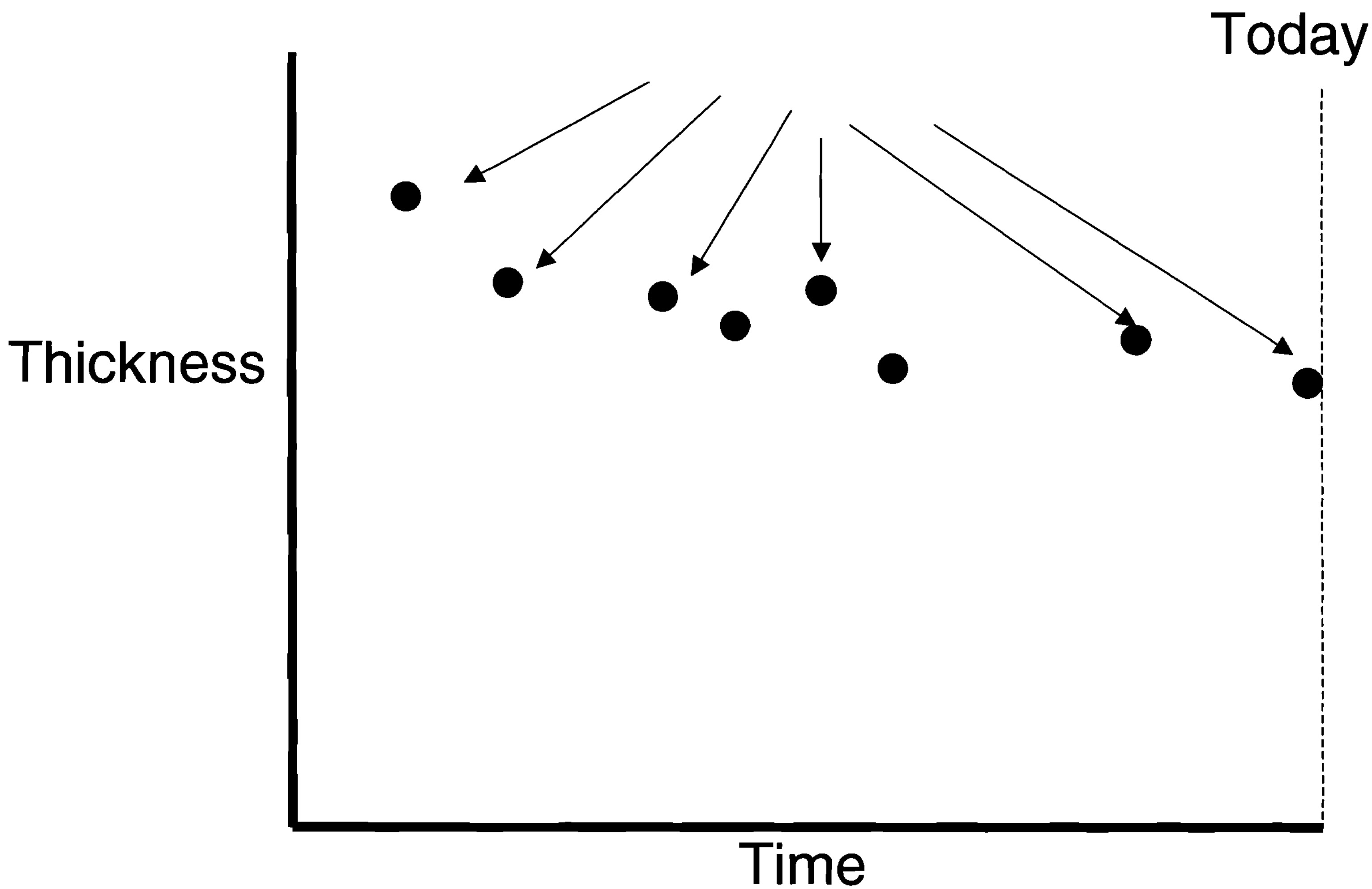
Statistical Methodology

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



Statistical Methodology

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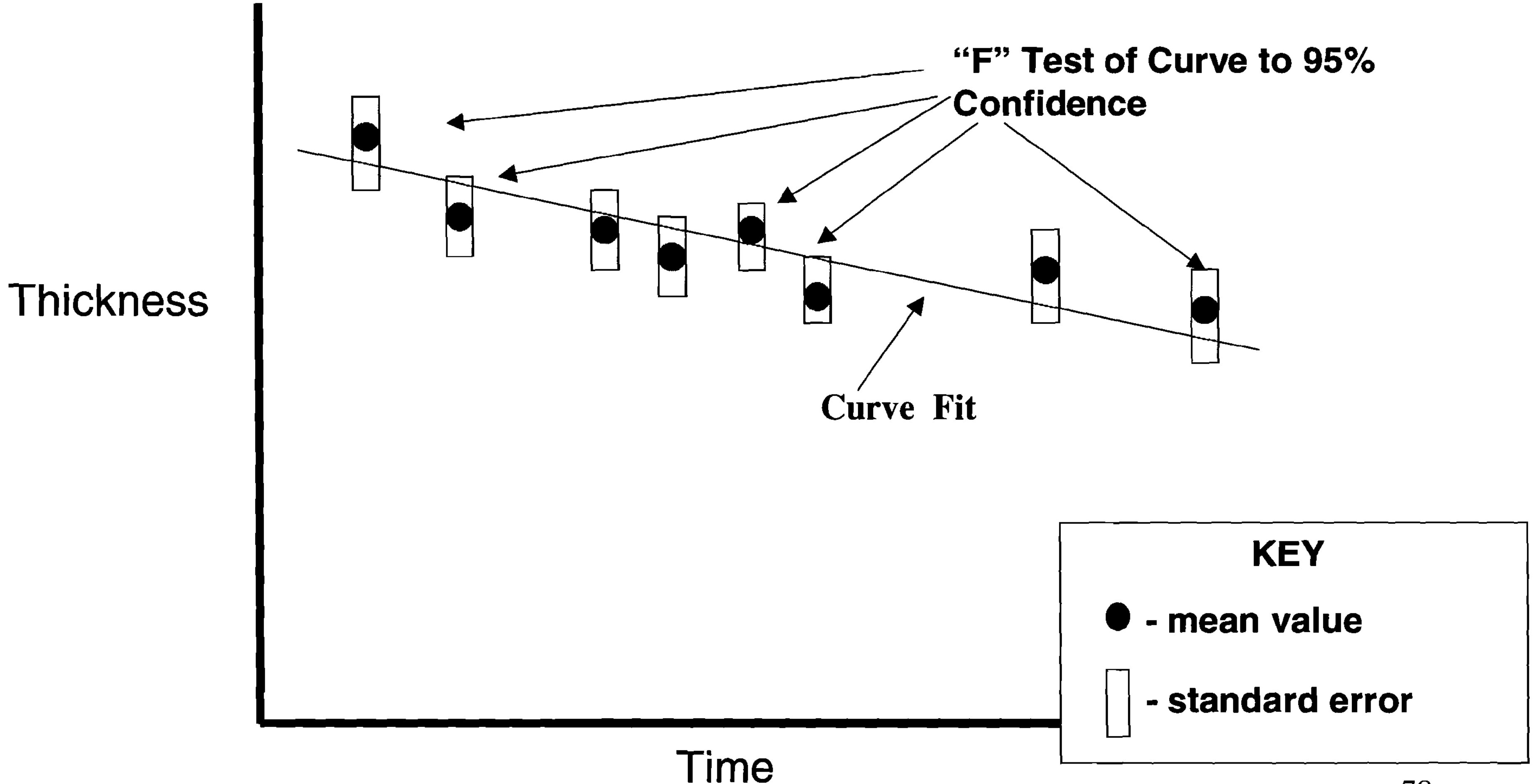
1) A curve fit based on the regression model is then developed.

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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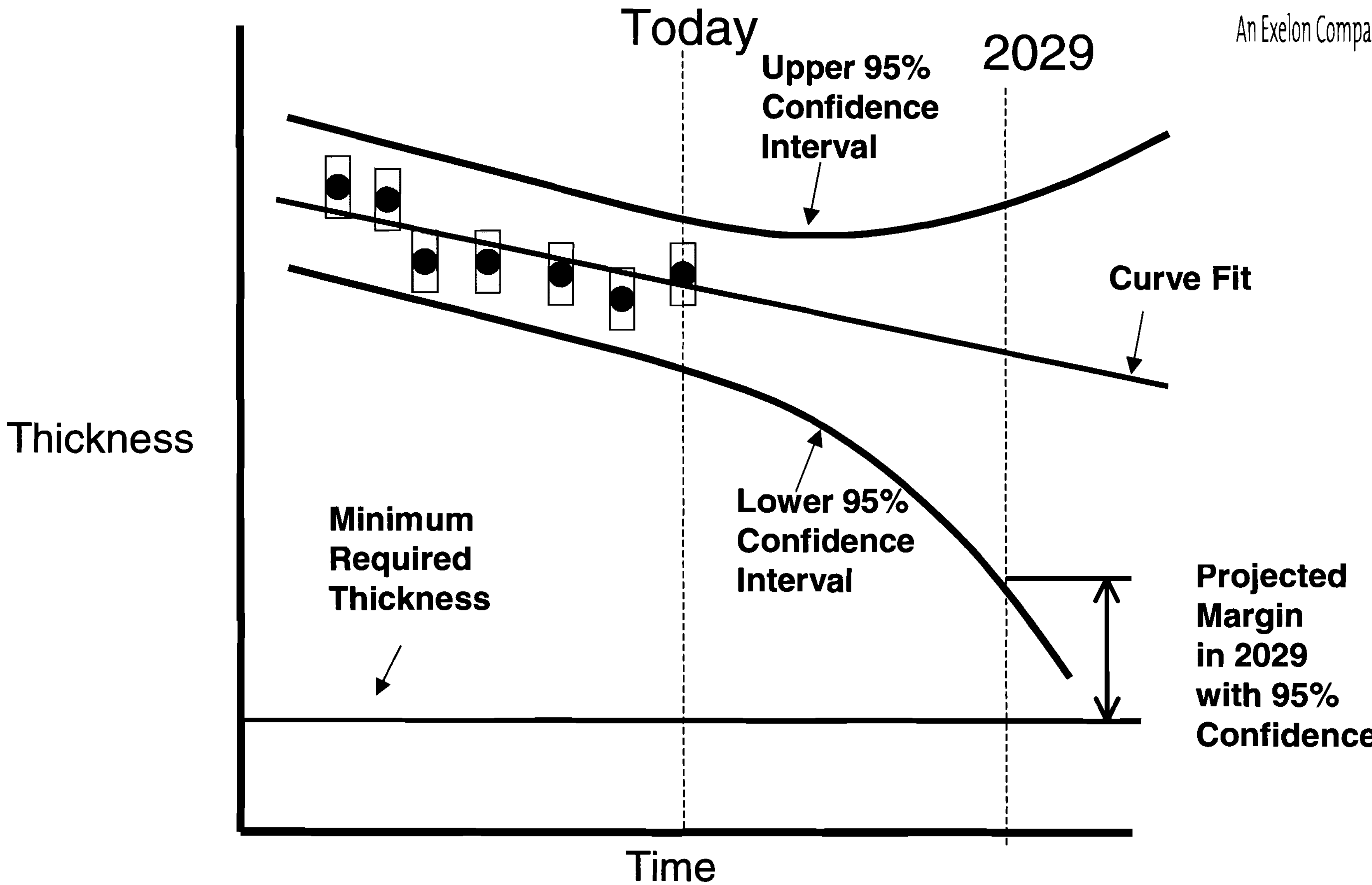

2006 Sand Bed Data Summary

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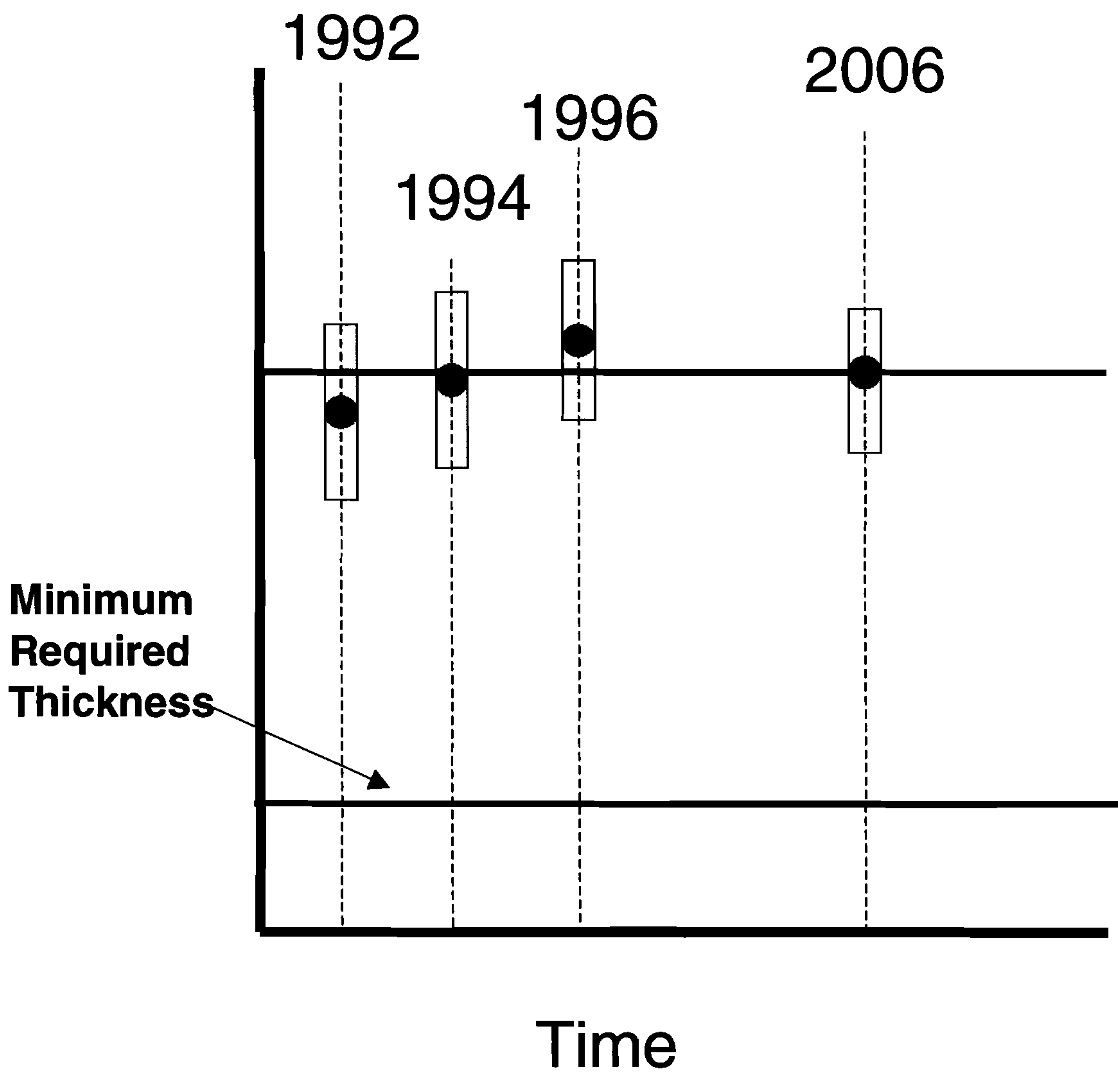

In the case of the 2006 sand bed inspections, there are only 4 inspections per location with most standard errors between +/- 8 and +/-16 mils

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

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>

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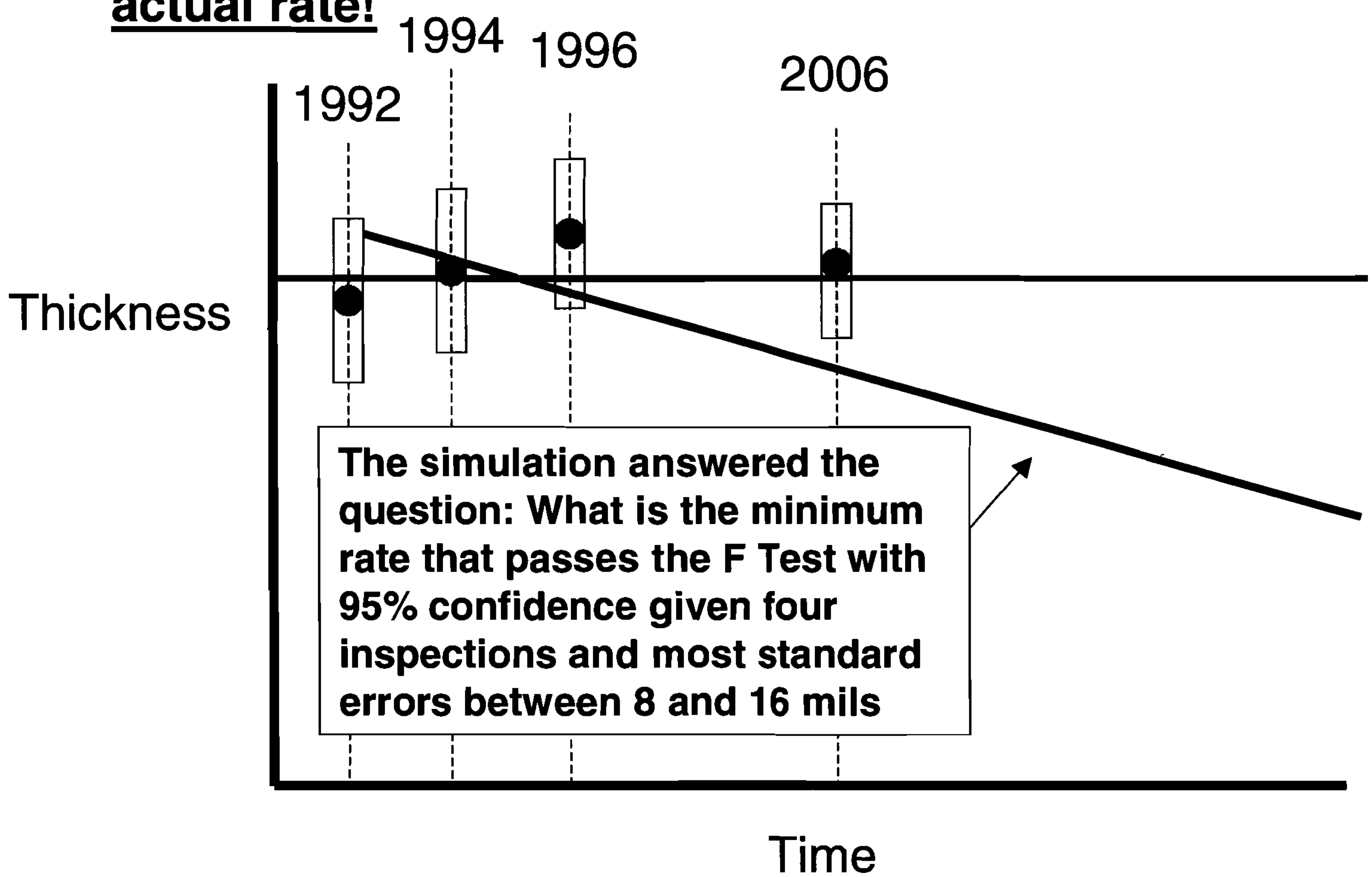
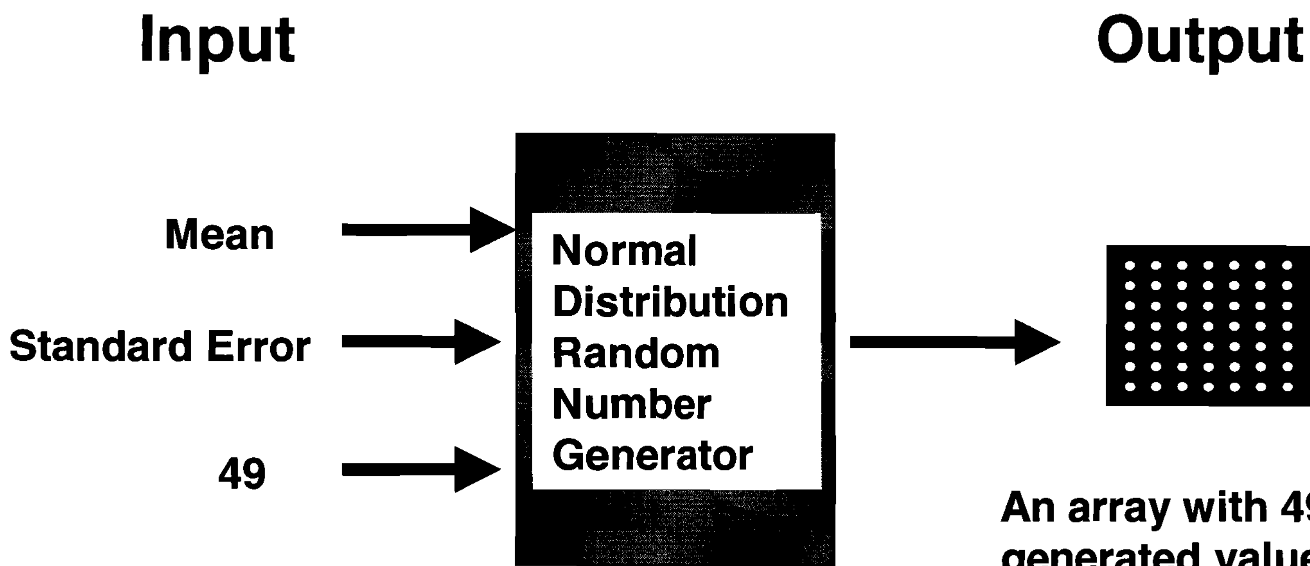


The simulation used a random number generator based on the normal distribution



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

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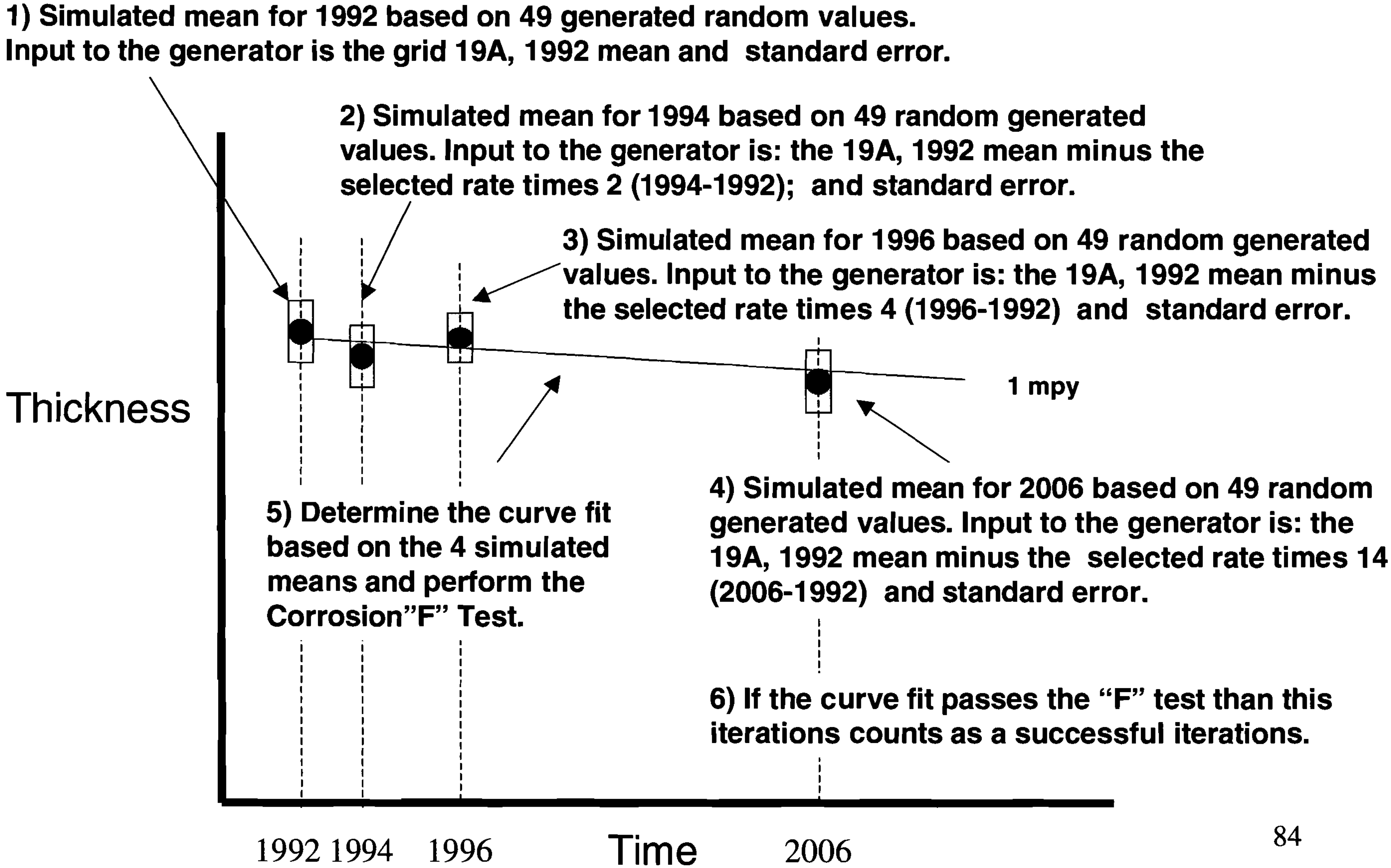
Chose a rate and performed 100 Iterations (Steps 1 through 6)



Simulation – Minimum Observable Corrosion Rate

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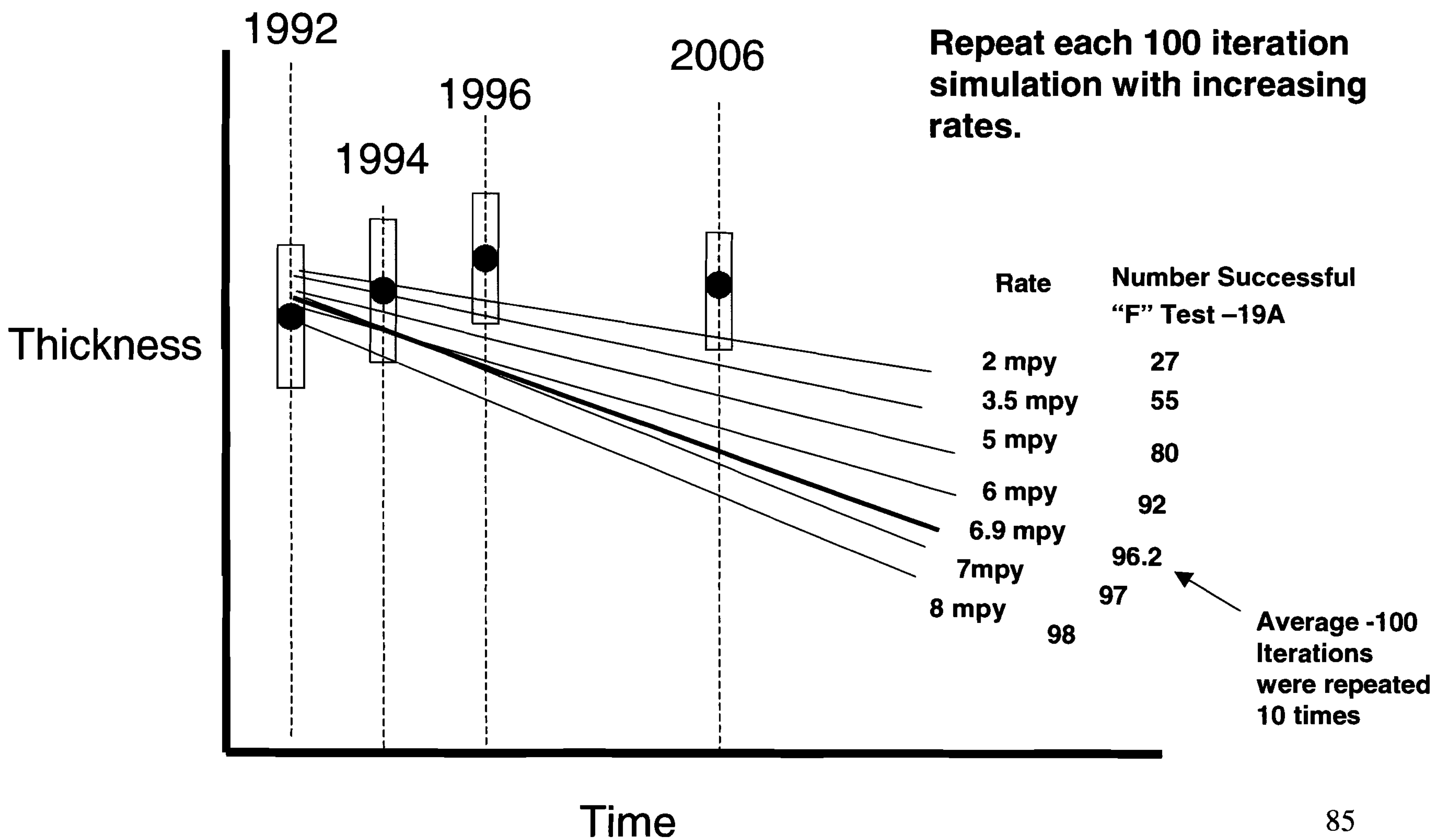
The minimum rate which consistently passes the Corrosion "F" Tests 95 out of 100 times is the Minimum Observable Corrosion Rate.

Repeat each 100 iteration simulation with increasing rates.



Next Required Inspection Based on the Minimum Observable Rate

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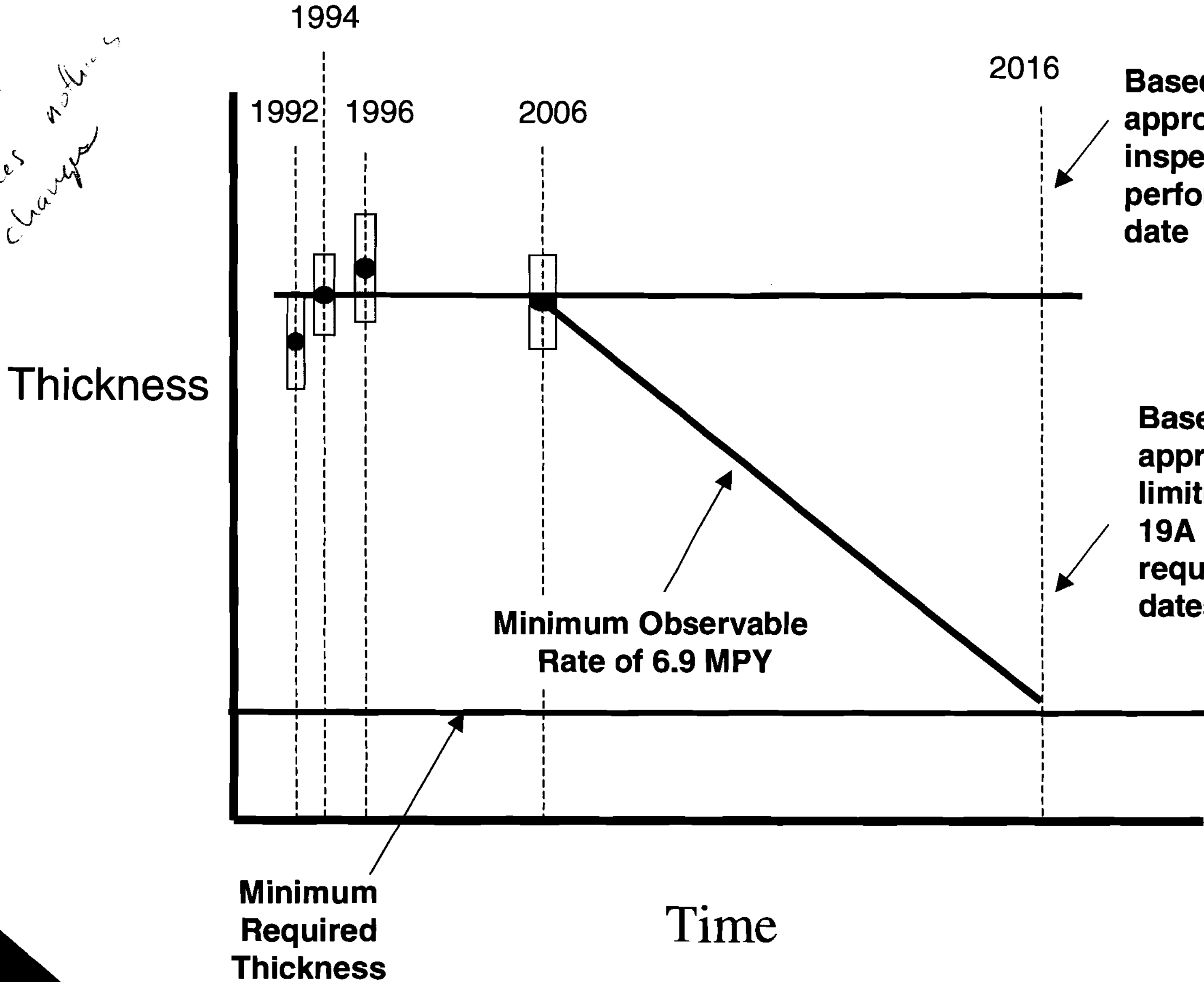
Graham assumes nothing changes



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

2006 Inspections
Sand Bed Region

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- 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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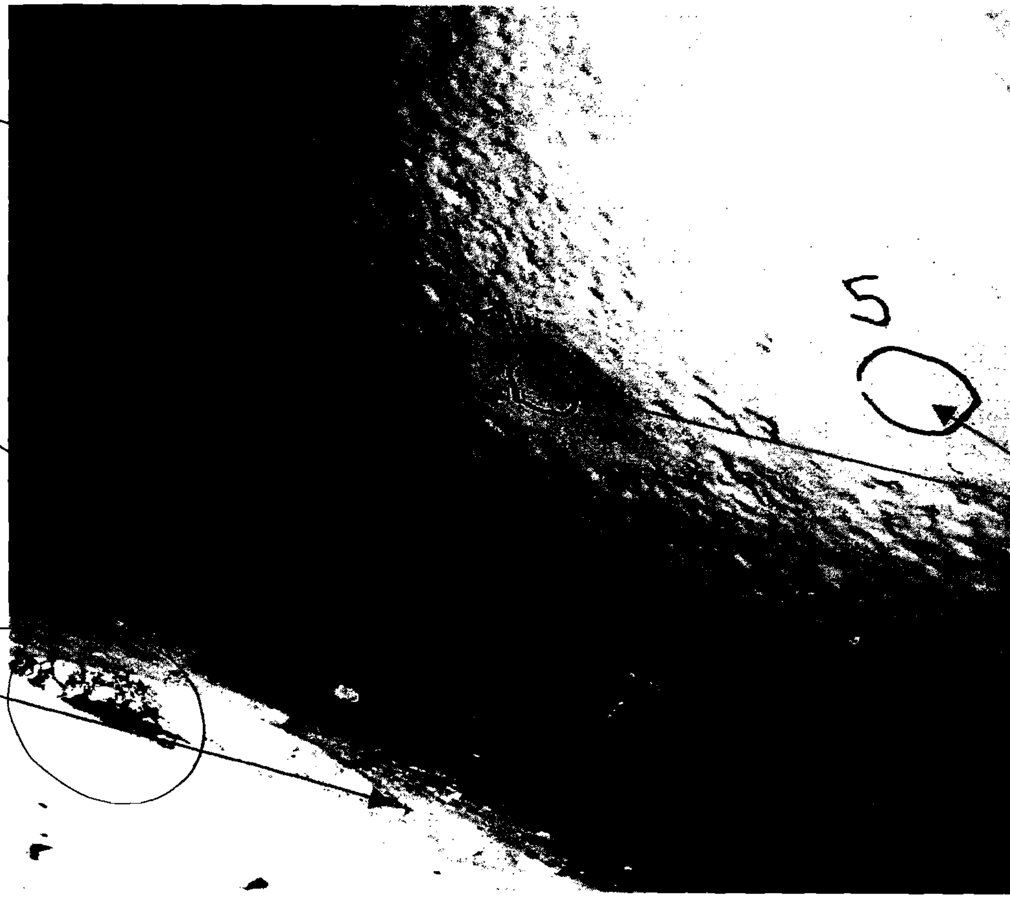
Shell

Caulk

surface rust from manway

Floor



External UT
Inspection locations

Bay 7 – Drywell shell, caulking, sand bed floor

Sand Bed Region 2006

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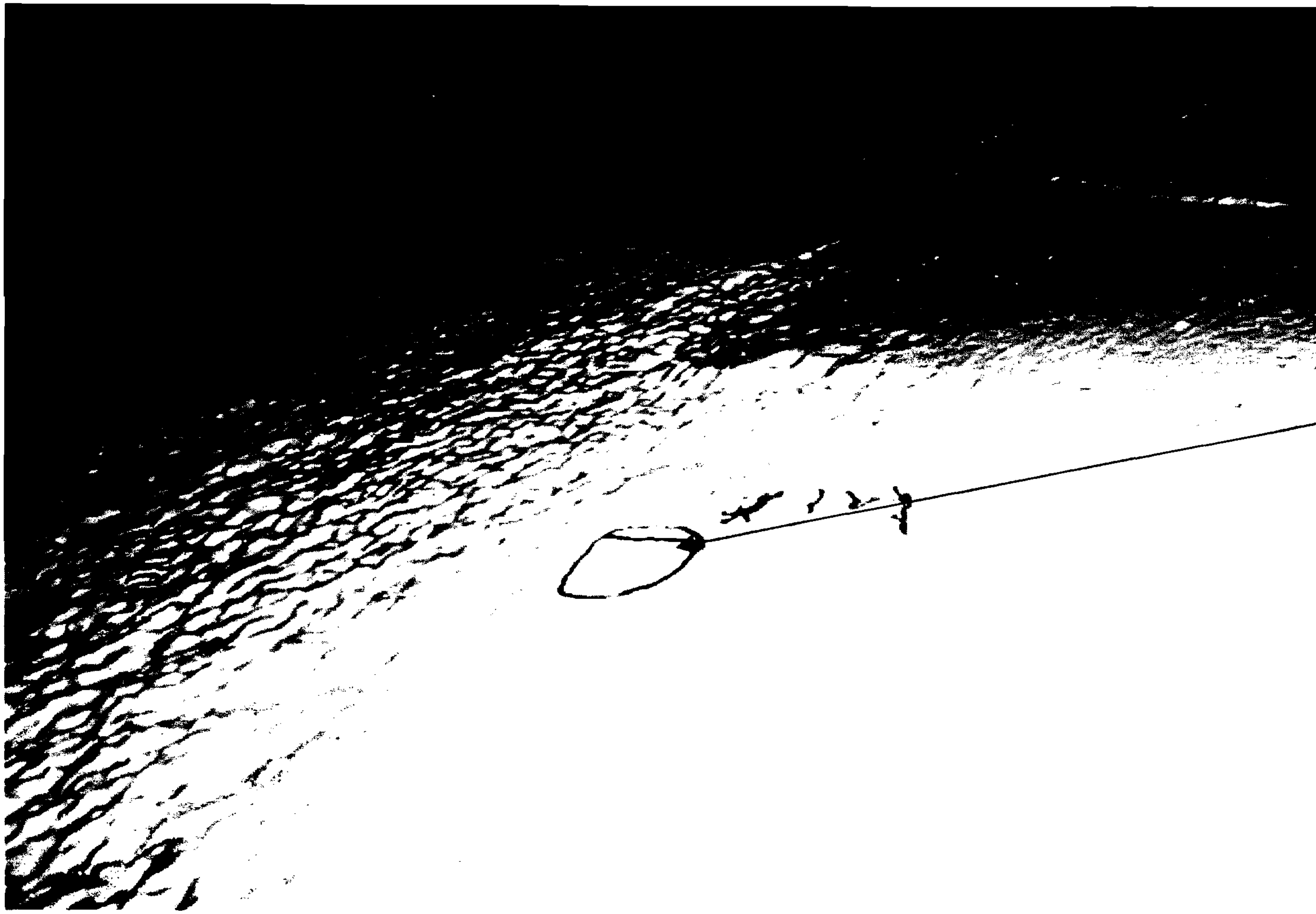

Reference for locating inspection points

External UT Inspection location

Bay 13 Drywell shell

Sand Bed Region 2006

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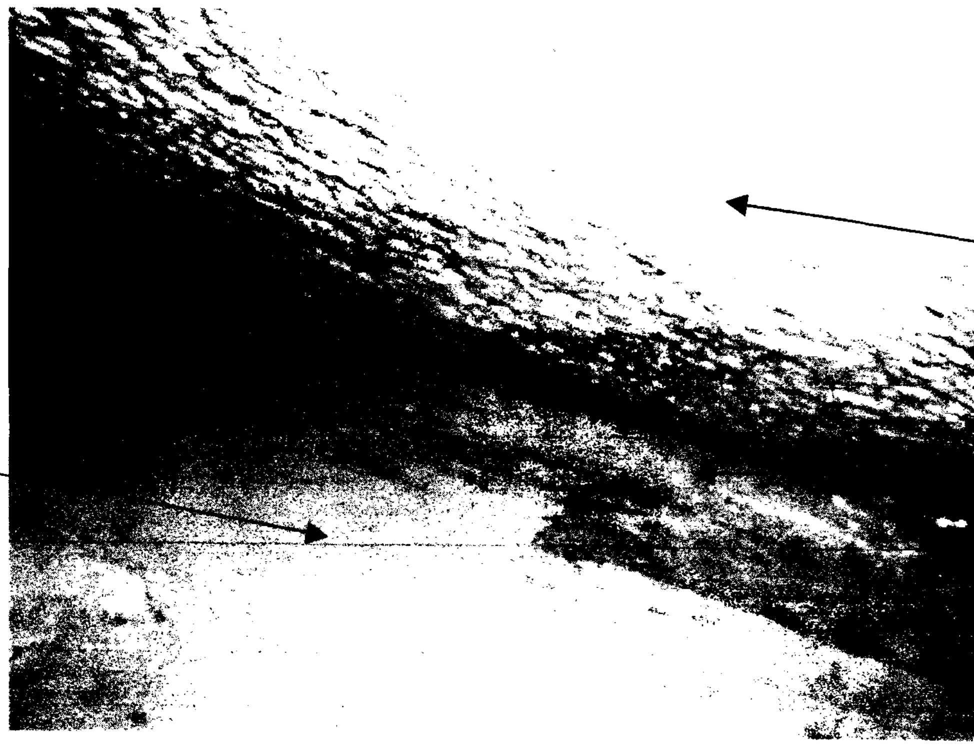

Bay 19 caulking

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

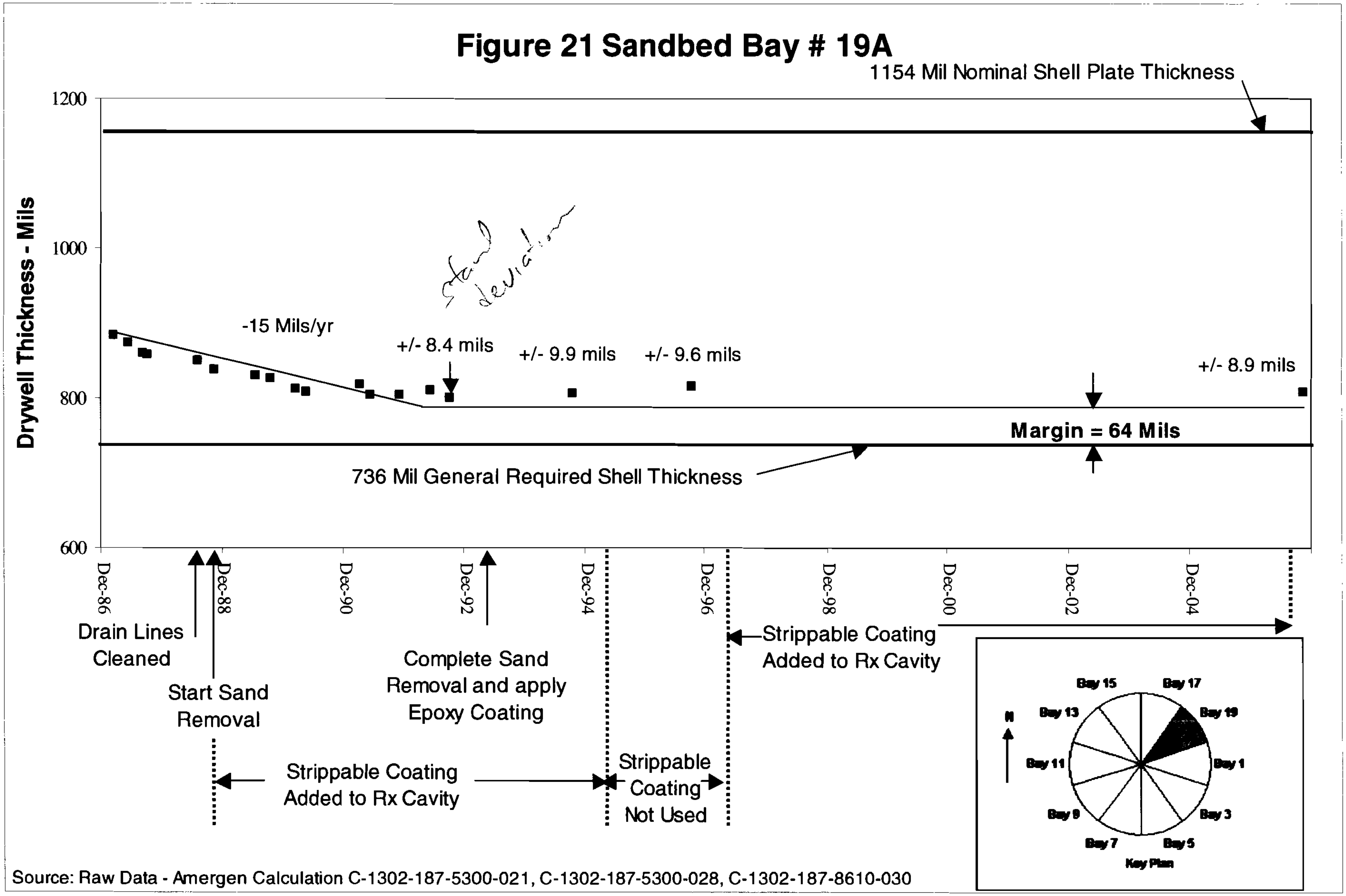
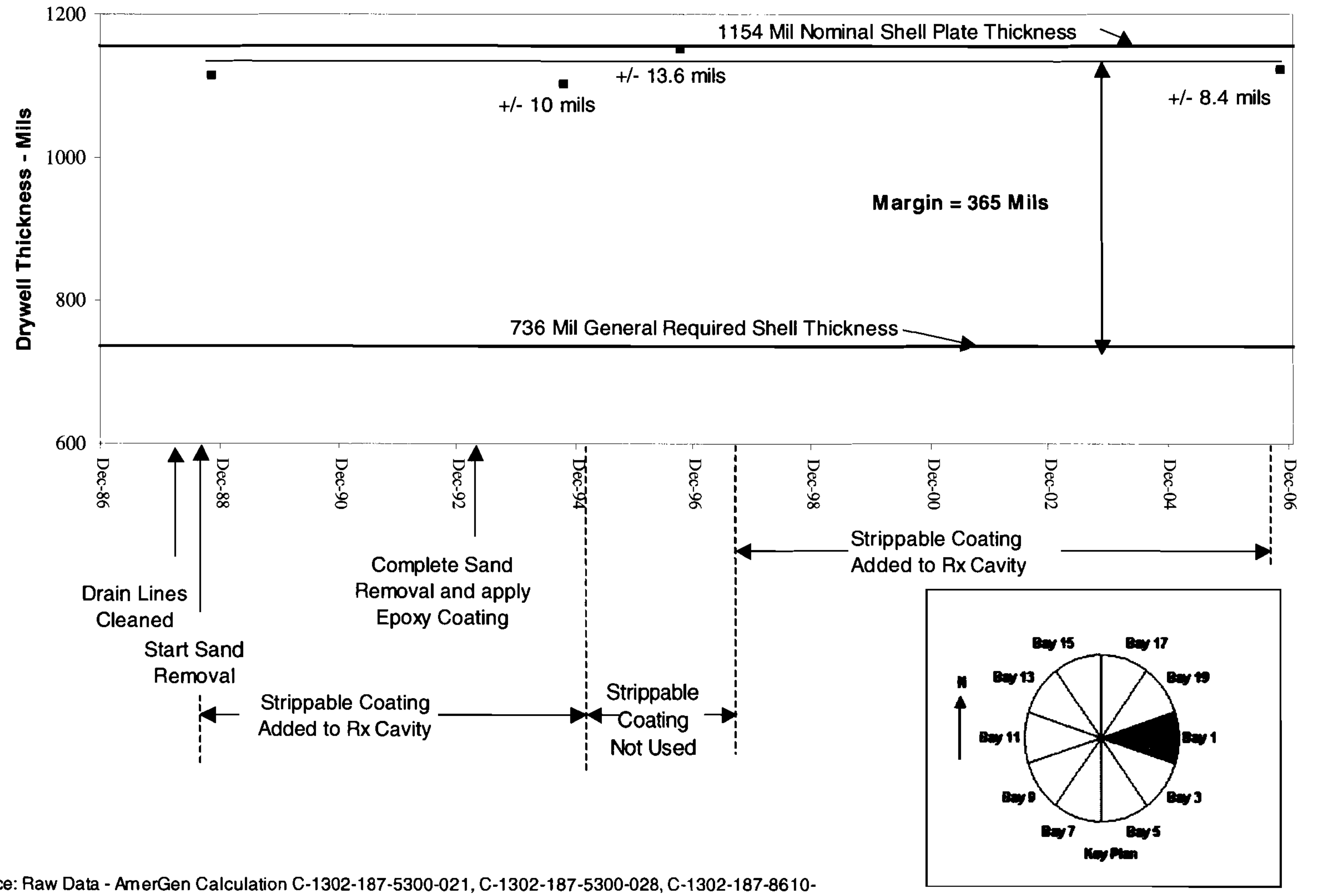


Figure 21 Sandbed Bay # 19A
1154 Mil Nominal Shell Plate Thickness
1200
1000
800
600
Drywell Thickness - Mils
-15 Mils/yr
+/- 8.4 mils
+/- 9.9 mils
+/- 9.6 mils
+/- 8.9 mils
Margin = 64 Mils
736 Mil General Required Shell Thickness
Dec-86
Dec-88
Dec-90
Dec-92
Dec-94
Dec-96
Dec-98
Dec-00
Dec-02
Dec-04
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
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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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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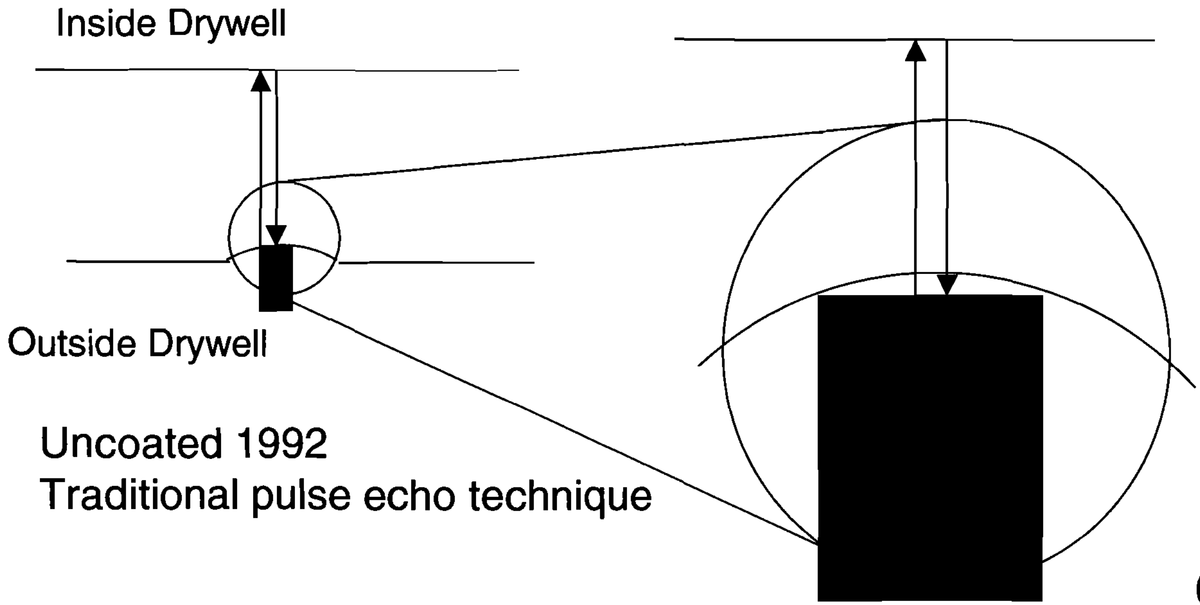
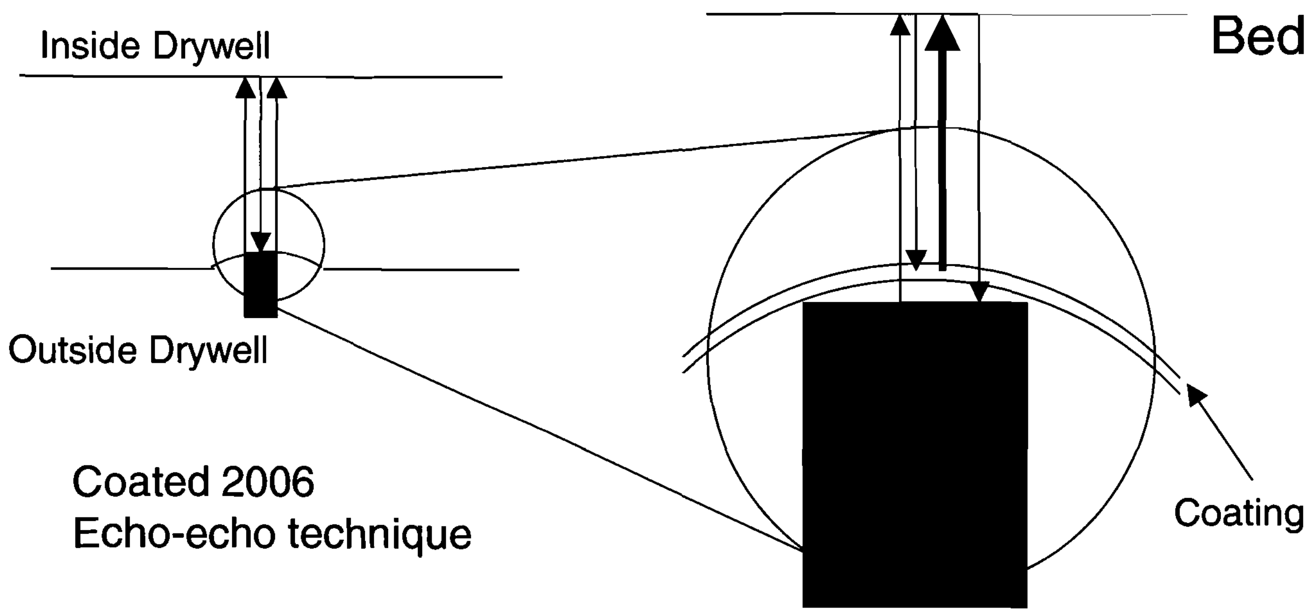
Concave Curvature Effects 1992 vs. 2006 External UT Data (106) Sand Bed Readings



Uncoated 1992
Traditional pulse echo technique



Coated 2006
Echo-echo technique

External UT Inspection Results

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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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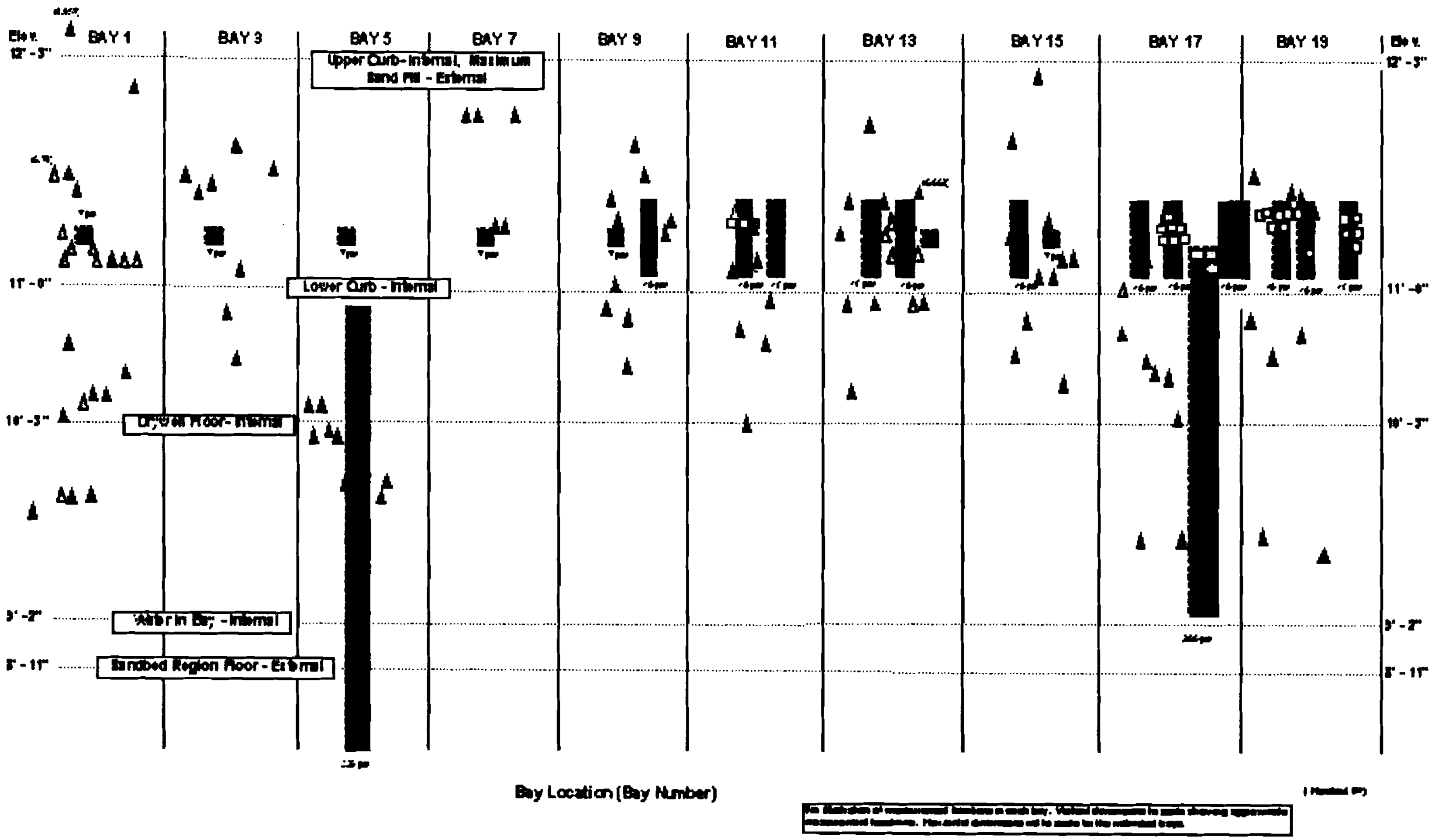
2006 Measurement Locations in the Sandbed Region

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



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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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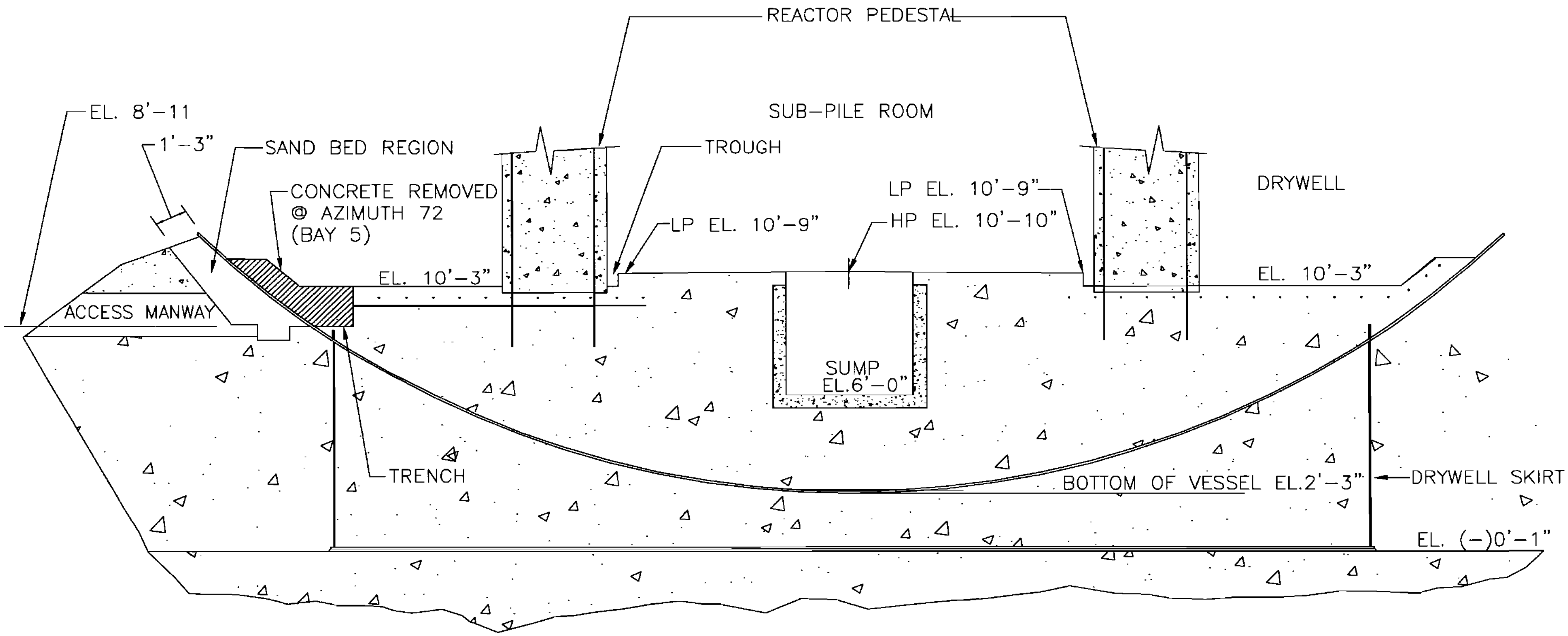
Embedded Shell Conclusions

- 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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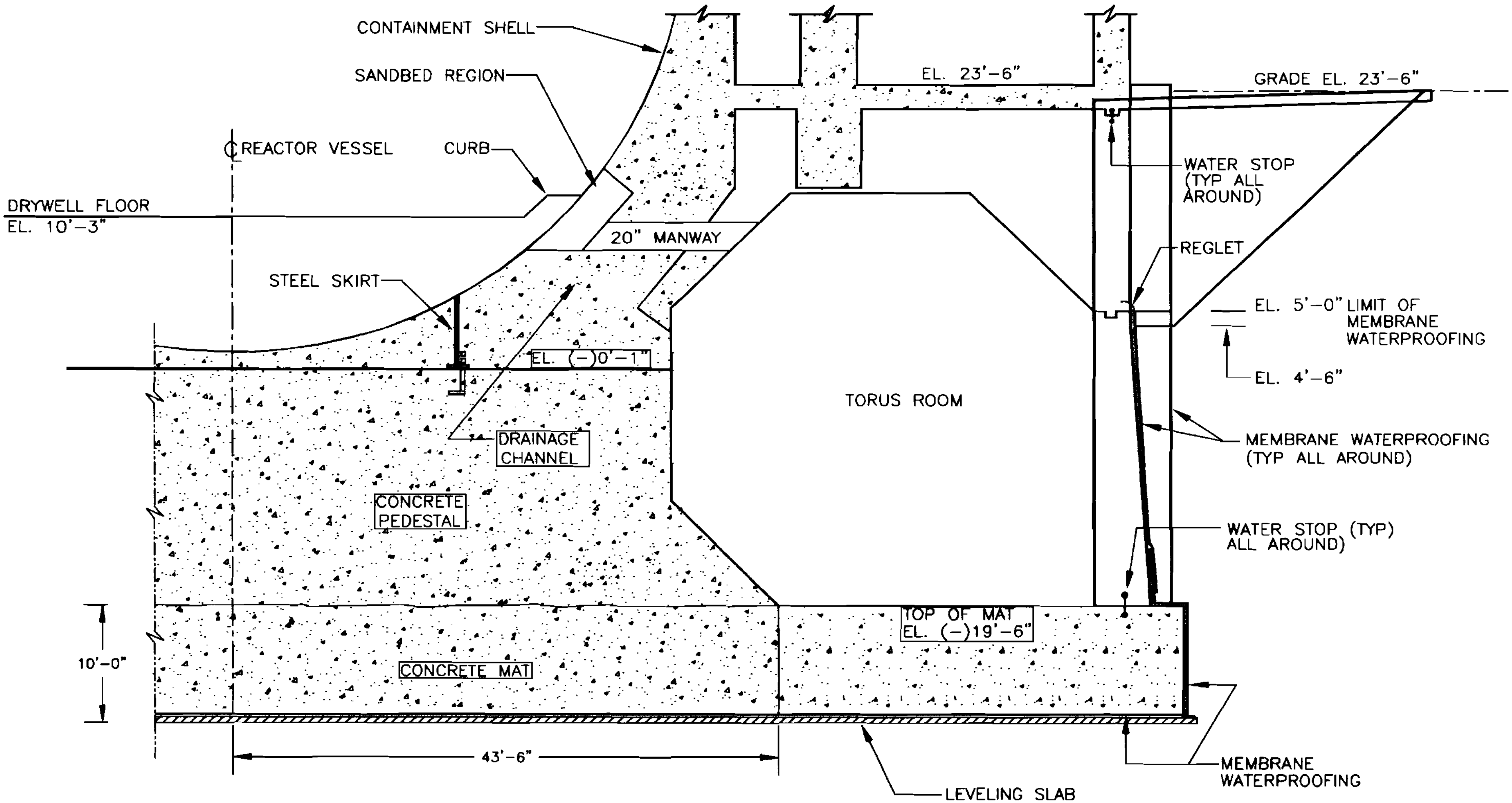
REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE



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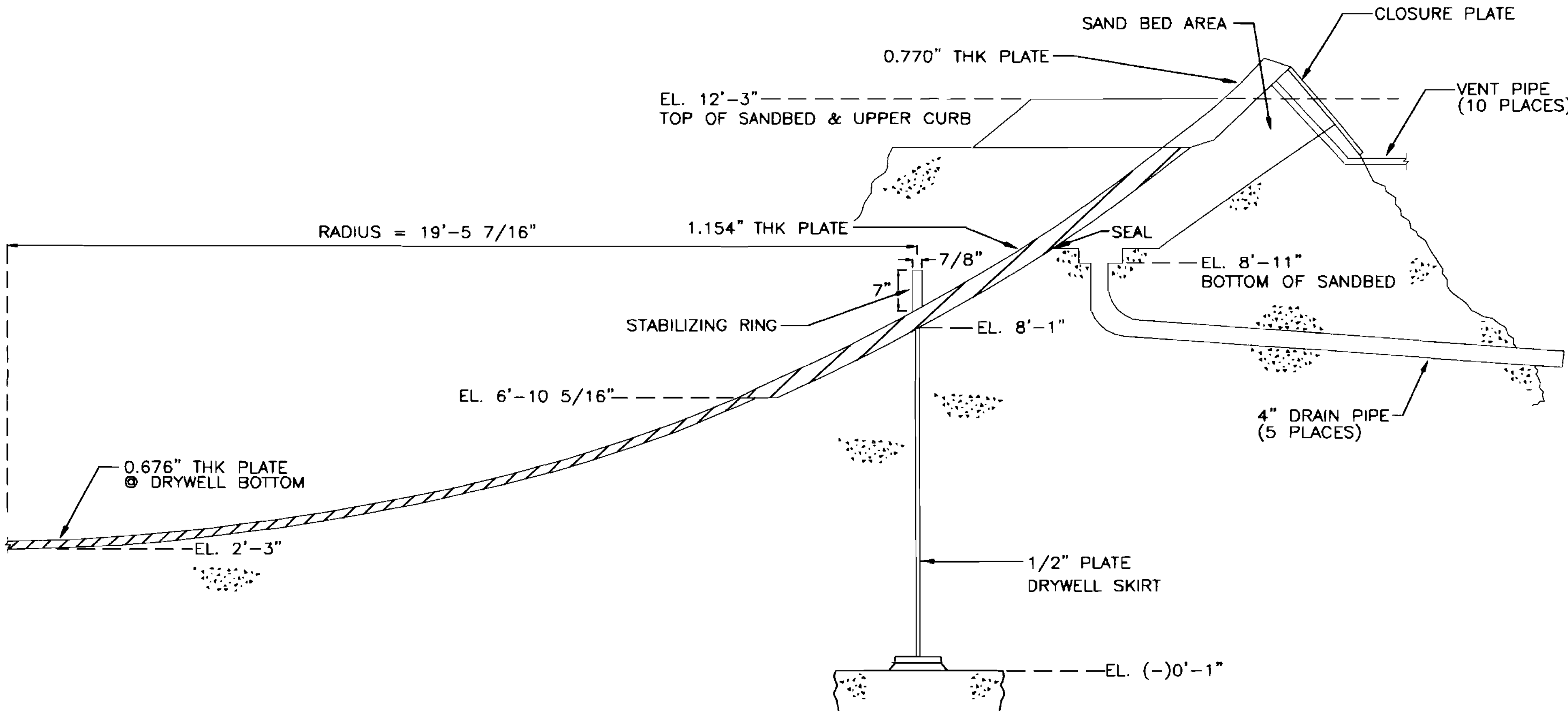

SECTIONAL VIEW OF SAND BED AREA AT VENT PIPE

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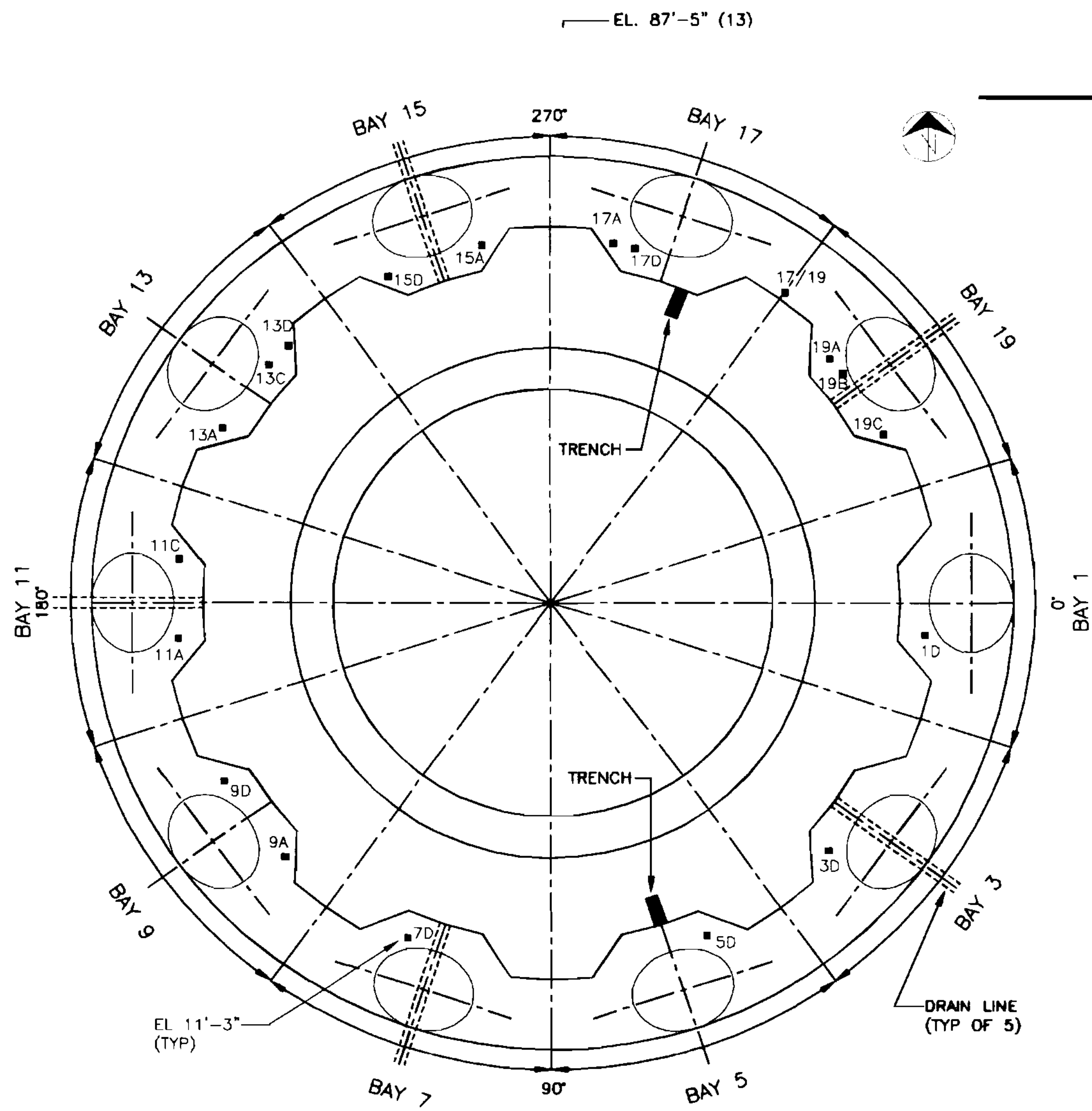

KEY PLAN

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

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Exterior Embedded Steel Environment

- 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)

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Interior Embedded Steel Environment

- 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

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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

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

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2006 Inspection Results Embedded Shell

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
17	1024 mils	±2.85 mils	986 mils	±4.18 mils	38 mils

How do you know this was arrested in 92?

↳ Assumption

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2006 Inspection Results Embedded Shell

- 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

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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

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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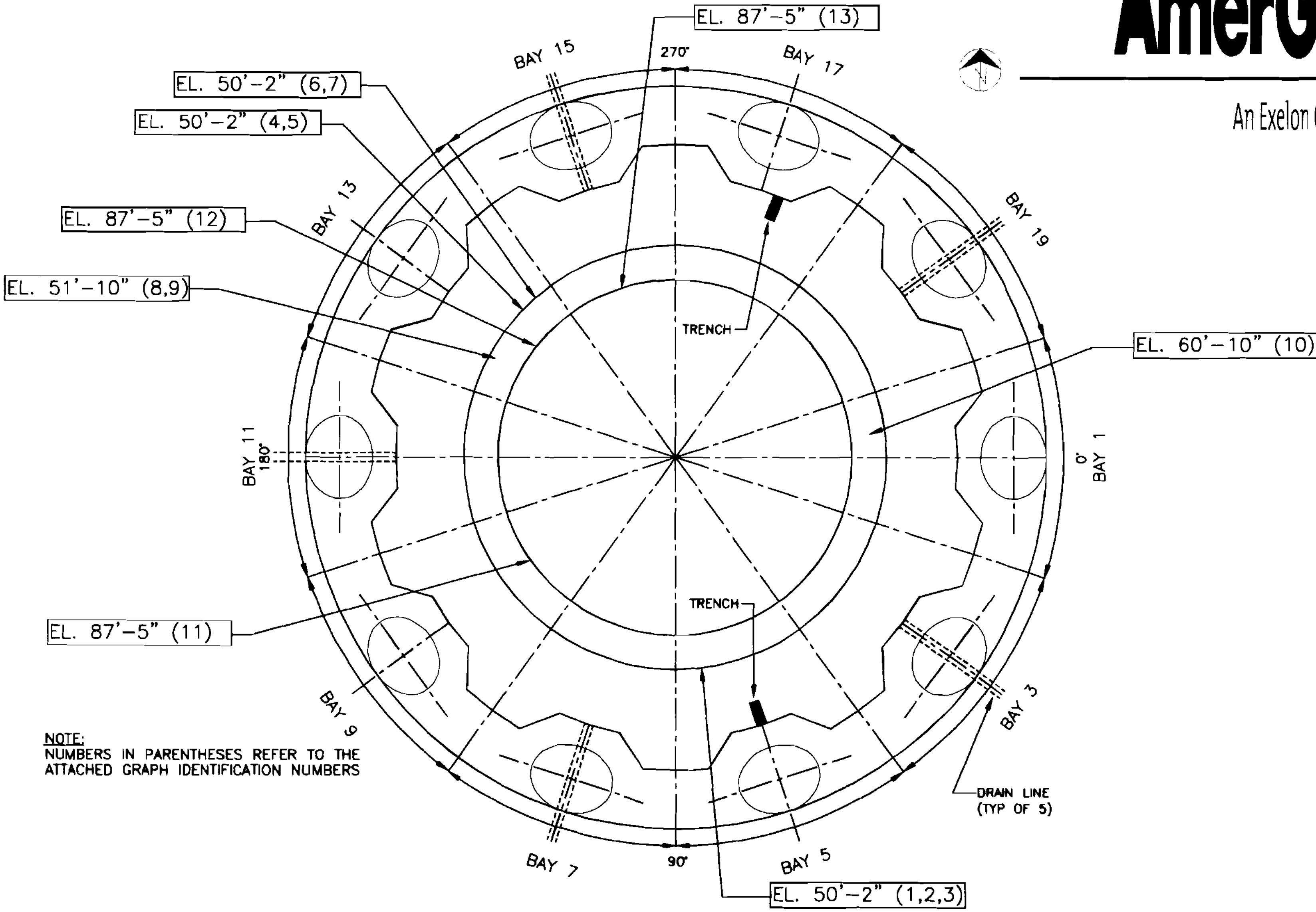

NOTE:
NUMBERS IN PARENTHESES REFER TO THE ATTACHED GRAPH IDENTIFICATION NUMBERS

KEY PLAN

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Upper Drywell UT Measurements

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

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Upper Drywell UT Measurements

Monitored Elevation	Location	Minimum Required Thickness mils[5]	Average Measured Thickness [1,2] mils												Projected Thickness in 2029 mils
			1987	1988	1989	1990	1991	1992	1993[3]	1994	1996	2000	2004	2006	
Elevation 51' 10"		518													
	Bay 13-32H					716	715 715 720	717 717		714	715	715	713	715	No Observable Ongoing Corrosion
	Bay 13-32L					686	683 683 682	683 676		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	622 620	619	620	614 612	629 614		613	613	604	612	617	No Observable Ongoing Corrosion
	Bay 13-28		643	641 642	645	643	635 629	641 637		640	636	635	640	642	No Observable Ongoing Corrosion
	Bay 15-31		638	636 636	638	642	628 627	631 630		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

Upper Drywell Shell Conclusions

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- 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

Overall Conclusions

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- 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