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

October 1, 2012

MEMORANDUM TO: ACRS Members

FROM: Peter Wen, Senior Staff Engineer ***/RA/***
Technical Support Branch, ACRS

SUBJECT: CERTIFIED MINUTES OF THE ACRS PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING ON LIMERICK GENERATING STATION ON SEPTEMBER 5, 2012

The minutes of the subject meeting were certified on September 29, 2012, as the official record of the proceedings of that meeting. Copies of the certification letter and minutes are attached.

Attachments: As stated

cc: E. Hackett
H. Gonzalez

UNITED STATES
NUCLEAR REGULATORY COMMISSION
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WASHINGTON, DC 20555 - 0001

October 1, 2012

MEMORANDUM TO: Peter Wen, Senior Staff Engineer
Technical Support Branch
Advisory Committee on Reactor Safeguards

FROM: William Shack, Chairman
Plant License Renewal Subcommittee
Advisory Committee on Reactor Safeguards

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING ON SEPTEMBER 5, 2012

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

William J. Shack

9/29/12

William Shack, Chairman Date
Plant License Renewal Subcommittee

Certified on: September 29, 2012 Issued by: October 1, 2012
Certified by: William Shack

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MINUTES OF THE ACRS LIMERICK GENERATING STATION
LICENSE RENEWAL SUBCOMMITTEE MEETING
SEPTEMBER 5, 2012

On September 5, 2012, the Advisory Committee on Reactor Safeguards (ACRS) Subcommittee on Plant License Renewal held a meeting regarding Limerick Generating Station, Units 1 and 2 license renewals in Room T-2B1, at 11545 Rockville Pike, Rockville, Maryland. The meeting convened at 8:30 a.m. and adjourned at 11:32 a.m. The entire meeting was open to the public.

Written comments from Dr. Lewis Cuthbert of the Alliance for a Clean Environment were received on September 3, 2012. Dr. Cuthbert's comments are attached to the meeting transcript.

ATTENDEES

ACRS Members/Consultants

William Shack, Chairman
John Sieber, Member
Gordon Skillman, Member
Dana Powers, Member
Charles Brown, Member
John Stetkar, Member
John Barton, Consultant

Peter Wen, ACRS staff – Designated Federal Official

NRC Staff

Melanie Galloway	Patrick Milano
Allen Hiser	Abdul Sheikh
Matt Homiack	Michael Modes
Rob Kuntz	James Medoff
Roger Kahkian	Raj Auluck
John Wise	Alice Erickson
Seung Min	Michelle Kichline
Angela Buford	Duc Nguyen
Brian Harris	Cliff Doutt
William Gardner	Bryce Lehman
Robert Sun	Andrew Prinaris
Bennett Brady	Rui Li
Albert Wong	Dennis Morey
Michael Marshall	William Holston
James Gavula*	Naeem Iqbal*

Exelon

Michael Gallagher	Dan Doran
Gene Kelly	Mark DiRado
Tom Daugherty	Chris Mudrick
Chris Wilson	John Hufnagel
Mark Miller	Mary Kowalski
Al Fulvio	James Jordan
R. H. Churomanski	Bob Dickinson
Mike Guthrie	Michelle Karasek
Brian Tracy	Deb Spamer
Ron Hess	David Tillman
Preet Soni	George Buduck
Greg Sprissler	Shannon Rafferty-Czincila
Martin Bonifanti	Brandon Shultz
Mike Yun	Leanne Birkmin
Christine Kirkead	David Clohecy
Ken Slough	

Mark Marquis, Underwater Construction Corporation
Barry Gordon, Structural Integrity Associates

Other Attendees

Alex Polonsky, Morgan Lewis
Tim Matthews, Morgan Lewis
Eric Blocker, STARS
Arden Aldridge, STPNOC
Steve Dorts*, First Energy Corp
Rigel Davis*, STARS

*Participating via telephone

SUMMARY

The purpose of the meeting was to review the license renewal application (LRA) for the Limerick Generating Station, Units 1 and 2 and the associated staff draft safety evaluation report (SER) with open items. The briefing was provided by representatives from the NRC staff and applicant, Exelon Generation Company, LLC. The meeting transcripts are attached and contains an accurate description of each matter discussed during the meeting. The presentation slides and handouts used during the meeting are attached to these transcripts.

The following table lists the significant issues that were discussed during the meeting with the corresponding pages in the transcript.

Significant Issues Discussed	**Reference Pages in Transcript**
Chairman Bill Shack opened the Limerick License Renewal Subcommittee meeting. He acknowledged that the Subcommittee had received written comments from Dr. Lewis Cuthbert of the Alliance for a Clean Environment. Dr. Shack stated that the purpose of this subcommittee meeting was to review the LRA for the Limerick Generating Station Units 1 and 2, the draft SER and associated documents. He noted that the ACRS does not review the Environmental Impact Statement.	4-5
Melanie Galloway (Acting Director, Division of License Renewal) noted that the Limerick LRA is the first license renewal application consistent with GALL Report Rev. 2. She commented that the recently court issued waste confidence decision will affect renewal schedule for Limerick license renewal.	7-8
Exelon presentation on the site description Issues discussed: ✓ Potential flooding due to Schuylkill River high water levels ✓ Output voltages and interconnectivity of 220KV and 500KV switchyards	10-12 11 11-12
Exelon provided an overview of Limerick operating history	12-13
Exelon provided an overview of Limerick LRA Issues discussed: ✓ Based on flow-accelerated corrosion (FAC) operation experience described in the LRA, Chairman Shack inquired about the applicant's plan to address the FAC-related issue. ✓ Based on Class 1 piping system environmental fatigue analysis results, described in LRA Table 4.3.3-2, Chairman Shack inquired about what kind of stress analysis was performed for reactor water cleanup piping which shows CUF of 0.999. ✓ Core shroud weld inspection and material type ✓ Current status of steam dryer in both units ✓ Internal inspections of buried safety-related service water piping ✓ Potential stress corrosion cracking in the closed cooling water systems ✓ The status of water chemistry operation in the closed treated water system ✓ The bolting integrity program related non-torque loosing problem ✓ Scoping issue related to lube oil storage enclosure ✓ Possible modification on the hardened vent ✓ Inspection of water control structures	13-28 15-16 16-17 17-18 19 20, also discussed in 96-99 22 23 24 25-26 26-27 27-28

Exelon discussed the open item related to suppression pool liner issue Issues discussed: ✓ The composition of the coating material used in Limerick suppression pool liner. ✓ The material condition of the liner and how it was inspected. ✓ Could coating problems observed at older Mark I containments occur at Limerick Mark II containments? ✓ How the coating material satisfies both liner protection and suction strainer clogging concern as described in Generic Letter 98-04. ✓ Coating inspection and coating maintenance plan ✓ Oversight of vendor work on underwater coating inspection ✓ Suppression pool water environment and general corrosion issue ✓ Re-coating material and operating experience ✓ Clarified the applicant's coating aging management program enhancements. ✓ Organic content of the suppression pool water chemistry	28-94 30 33 37-39 39-44 46-48, also discussed in 72-74 50-54 57-61 80-84 84-87 92-94
NRC Staff Presentation 1. SER Overview 2. Region I inspection 3. Open item related to suppression pool liner issue 4. Open item related to operating experience 5. Time-Limited Aging Analyses Issues discussed: ✓ Limerick plant material conditions ✓ Inspection of diesel fuel oil storage tank ✓ Projected lifetime of zinc coating and the need for coating inspection ✓ Inspection of re-coated expoxy coating and zinc coating	94-134 94-106 106-108 115-129 129-131 131-133 108 110-114 122-125 126-128
Chairman Shack adjourned the meeting at 11:32 a.m.	136

FOLLOW-UP ITEMS	
Issue	**Reference Pages on Transcript**
During the Scoping and Screening Methodology audit, the staff selected four systems (essential service water system, fuel pool cooling and cleanup system, emergency diesel generator system, and fuel transfer and air start systems) for audit. Member Skillman asked: a. What is the basis for selecting only those four systems? Why these 4? b. Are these 4 systems the same 4 that have been chosen at other plants in Region I? c. Why not 6 or 7 systems? Or why two different systems from these 4? The staff will provide more detailed response later.	103-104

Based on cathodic protection system operation experience, Member Skillman asked whether there is any correlation between operability of the cathodic protection system and the observed Limerick plant liner corrosion. Was it a design consideration?	118-120

BACKGROUND MATERIALS PROVIDED TO THE SUBCOMMITTEE

1. Exelon Generation Company, LLC, “Limerick Generating Station, Units 1 and 2 – License Renewal Application,” June 22, 2011 (ML11179A101).

2. NRC Safety Evaluation Report With Open Items Related to the License Renewal of Limerick Generating Station, Units 1 and 2, July 2012 (ML12213A721).

3. Email from Dr. Lewis Cuthbert, the Alliance for a Clean Environment to Peter Wen, ACRS, NRC, “Comments for 9-5-12 Subcommittee meeting,” September 3, 2012

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee on Reactor Safeguards License Renewal Subcommittee
Docket Number:	(n/a)
Location:	Rockville, Maryland
Date:	Wednesday, September 5, 2012

Work Order No.: NRC-1863 Pages 1-136

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

+ + + + +

LICENSE RENEWAL SUBCOMMITTEE

+ + + + +

WEDNESDAY

SEPTEMBER 5, 2012

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., William J. Shack, Chairman, presiding.

COMMITTEE MEMBERS:

WILLIAM J. SHACK, Chairman

CHARLES H. BROWN, JR. Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

JOHN D. SIEBER, Member

GORDON R. SKILLMAN, Member

JOHN W. STETKAR, Member

ACRS CONSULTANTS PRESENT:

JOHN BARTON

DESIGNATED FEDERAL OFFICIAL:

PETER WEN

A-G-E-N-D-A

P-R-O-C-E-E-D-I-N-G-S

8:28 a.m.

CHAIRMAN SHACK: The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I'm Bill Shack, chairman of the Limerick License Renewal Subcommittee.

ACRS members in attendance are Jack Sieber, Dick Skillman, Harold Ray, Dana Powers, John Stetkar, Charles Brown and our consultant John Barton. Peter Wen of the ACRS staff is the designated federal official for this meeting.

The purpose of this meeting is to review the License Renewal Application for the Limerick Generating Station Units 1 and 2, the draft Safety Evaluation Report and associated documents. I would note that the ACRS does not review the Environmental Impact Statement.

We will hear presentations from the representatives of the Office of Nuclear Reactor Regulation and the applicant, Exelon Generation Company, LLC. The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberation by the full committee.

The rules for participation in today's

meeting have been announced as part of the notice of this meeting previously published in the Federal Register. We have received written documents from Dr. Lewis Cuthbert of the Alliance for a Clean Environment regarding today's meeting.

A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore we request the participants in this meeting use the microphones located throughout the reading room when addressing the subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume so they can be readily heard.

We have several people on phone bridge lines listening to the discussion. To preclude interruption of the meeting the phone line is placed on a listen-in mode.

We will now proceed with the meeting and I call upon Ms. Melanie Galloway of the Office of Nuclear Reactor Regulation to introduce the presenters.

MS. GALLOWAY: Okay, great. Thank you, Dr. Shack. My name is Melanie Galloway. I'm the acting director of the Division of License Renewal at NRR. And as always on behalf of the staff we are pleased to be here today to interact and discuss the Limerick License Renewal Application with the ACRS subcommittee.

There are a few things I want to note first. We do have representatives from the staff here to support our presentation. We have next to me Patrick Milano, the project manager for Limerick. He has recently been assigned in the last month so we're indoctrinating him early to the process of license renewal in participating in this meeting.

I also have a number of branch chiefs here to support. Dennis Morey is our Safety Projects Branch chief. Michael Marshall is the branch chief associated with our Electrical and Structural Branch. And Raj Auluck is in the front row over there and he is our branch chief for the Aging Management of Plant Systems.

In addition, Michael Modes is here from Region I to talk about the inspection process associated with Limerick license renewal. And also we have Jim Gavula who's a representative from our Region III office actually assigned to license renewal but placed in Region III.

I did want to note a few things about the application. First of all, the Limerick application is the first application that we have reviewed consistent with GALL Rev 2. So that's of particular note. We do believe that GALL Rev 2 was successful in introducing certain efficiencies in the review and I think the Limerick application supported that.

Also, I want to note that the Limerick application was of particular high quality, and that also contributed very significantly to the efficiency and effectiveness of the NRC review. That was also indicated by the number of RAIs we had on the application. The number of first round RAIs was only 150 and that is sufficiently lower than other applications which we have in-house now and which we see.

And of note also is the fact that the Limerick application is part of the Exelon fleet and the quality of the application not only applies to Limerick but it's also typical of what we see from other Exelon applications. So kudos to the applicant for the good job they've done in making our job easier.

In addition, I also want to commend the applicant for the background documentation that they provided to us on our onsite audits. They were extremely thorough and again that made our review much more efficient and much more effective. And as a result of this exchange we've had with the applicant in light of the quality that they provided to us our safety review has maintained the current schedule and that is good news.

Also, as a result of the exchange we've had so far you'll see that we only have two open items. And again that is reflective of the low number of RAIs and the quality of the application.

Now, I do want to mention while I know the ACRS does not review the environmental aspect of the reviews I do need to note that the waste confidence decision which was recently issued by the court has affected review schedules for license renewal. And while the safety review schedule for Limerick remains on schedule the effect of the waste confidence decision and the determination of what the staff needs to do in order to respond to the court's decision is going to cause an ultimate delay associated with Limerick license renewal.

At this point that concludes my opening remarks and I'll turn it over to Mike Gallagher, senior vice president for license renewal with Exelon.

MR. GALLAGHER: Okay. Thanks, Melanie. Good morning. My name is Mike Gallagher. I'm the vice president of license renewal for Exelon. Slide 1, please?

Before we begin today's presentation I'd like to introduce the presenters. To my right is Gene Kelly. Gene is the Limerick license renewal manager for Exelon. Gene has 38 years nuclear power plant experience including 13 at Limerick.

To Gene's right is Dan Doran and Dan is the Limerick engineering director. Dan has 21 years nuclear power plant experience at Limerick.

To Dan's right is Mark DiRado. Mark is our programs engineering manager. Mark has 13 years of nuclear power plant experience at Limerick.

To Mark's right is Barry Gordon. And Barry is a senior consultant and corrosion specialist with Structural Integrity Associates.

In addition to today's presenters we also have with us Chris Mudrick. And Chris is our senior vice president of mid-Atlantic operations. And we have Tom Daugherty and Tom is our site vice president at Limerick. Slide 2.

Slide 2 shows our agenda for the presentation. We will begin with the description of the site and an overview of the operating history followed by an overview of the License Renewal

Application. We will then continue with the discussions of the open items regarding the suppression pool and operating experience.

We've developed a comprehensive, high-quality License Renewal Application and a robust aging management program that will ensure the continued safe operation of Limerick. We appreciate this opportunity to make this presentation and look forward to answering any questions you might have.

I'll now turn the presentation over to Dan Doran. Dan?

MR. DORAN: Thank you, Mike. Slide 3, please. Good morning. My name is Dan Doran and I am the engineering director at Limerick Generating Station.

Limerick Units 1 and 2 are General Electric BWR/4 designs with Mark II containments. They are owned and operated by Exelon Corporation.

The Limerick Generating Station is located on the east bank of the Schuylkill River in Limerick Township of Montgomery County, Pennsylvania and it's approximately 4 miles down-river from Pottstown, 35 miles up-river from Philadelphia.

On this slide you will see the Schuylkill River which is one of our two non-safety related makeup water sources, the Schuylkill River Pump House, the independent spent fuel storage installation, the Unit 1 225 kV switchyard, the Unit 2 500 kV switchyard and the spray pond which is our ultimate heat sink. Limerick Generating Station also has four emergency diesel generators per unit.

Slide 4, please.

MR. BARTON: Let me ask you a question on this slide. Schuylkill River sometimes overflows its banks. I used to live in Cherry Hill so I remember about the Schuylkill River. What effect has the Schuylkill River high levels affected the site?

MR. DORAN: It has not affected the site. The site ground elevation is 85 feet above the Schuylkill River.

MR. BARTON: All right, thank you.

MEMBER SKILLMAN: Question, please. With the two different voltages in the switchyards do the two units generate at different voltages?

MR. DORAN: They do not generate coming out of the generator at different voltages. They are stepped up to 200 kV for Unit 1 and 500 kV for Unit 2. The generator terminal voltages are the same.

MEMBER SKILLMAN: Thank you.

MEMBER SIEBER: Are those switchyards

interconnected?

MR. DORAN: Excuse me?

MEMBER SIEBER: Are those switchyards interconnected onsite?

MR. DORAN: They can be interconnected through a cross-tie line that we have. We can supply power from both units from either of the units that are cross-tied. That's correct.

MEMBER SIEBER: Thank you.

MR. DORAN: Slide 4, please. This slide provides an overview of Limerick's history as well as the major station improvements.

Limerick was initially licensed to 3,293 megawatts thermal in 1984 for Unit 1 and 1989 for Unit 2. Following a successful startup test program commercial operation began in 1986 and 1990 for Unit 1 and Unit 2 respectively.

A 5 percent increase in rating of power on both units was performed in the 1995-1996 time frame. And on April 8th of last year a 1.65 percent measurement uncertainty recapture power uprate was implemented which increased the thermal rating on each unit to their current rating of 3,515 megawatts thermal.

Exelon has continued to make substantial improvements to both Limerick units such as turbine rotor replacements, digital feedwater control modifications, independent spent fuel storage installation, main transformer replacements, and most recently the addition of recirc pump adjustable speed drives.

Limerick is operated on 24-month fuel cycles. The current 24-month capacity factor is 91.6 percent for both units.

The License Renewal Application was submitted on June 22nd, 2011. Our current licenses expire on October 26th, 2024 for Unit 1 and June 22nd, 2029 for Unit 2.

I will now turn it over to Gene Kelly who will present to you the highlights of the License Renewal Application.

MR. KELLY: Thank you, Dan. Slide 5, please? Good afternoon. My name is Gene Kelly and I'm the license renewal manager. My portion of the presentation covers the highlights of our License Renewal Application including aging management programs, commitments and an overview of the two open items in the SER. Slide 6, please.

In preparing the application Exelon used industry and NRC guidance with the goal of making our application as consistent with the GALL as possible. Our submittal was based on GALL Revision 2.

There are 45 aging management programs including 34 existing programs, 11 new programs developed. Twelve of the existing programs required no changes to align with the GALL. Twenty-one of the existing programs required enhancements to align with the GALL. The one exception to the GALL is associated with the reactor head closure stud bolting program, specifically the preventive measures for measured or actual yield strength.

There are 47 license renewal commitments. These commitments are managed under an existing process consistent with NEI 99-04 and tracked as part of that process.

Forty-five of these commitments are associated with aging management programs. One commitment institutes operating experience program enhancements and another commitment will reevaluate a Unit 1 recirculation nozzle safe-end flaw that was mitigated by a mechanical stress improvement process in 1992 prior to entering the period of extended operation. Slide 7, please.

CHAIRMAN SHACK: Before we get into this I just -- since we don't seem to have an opening to discuss other parts of the license renewal thing let me just ask some questions about some other items.

One I was concerned about, I was looking at the flow-assisted corrosion evidence and in 2008 you had 62 inspections on Unit 1 and you replaced 454 feet of small-bore piping. In 2010 you did 102 inspections and replaced 442 feet of small-bore and 74 feet of large-bore piping.

On trending that doesn't look real good. How much susceptible piping do you have left and do you anticipate that kind of replacement going forward in the future?

MR. DIRADO: Sure. The flow-accelerated corrosion program is fleet-wide and it's based on known industry regulations and requirements. As part of the flow-accelerated program all of the susceptible piping is modeled. I don't have a total number available to me. We can certainly provide that.

But what I will say is that as we make enhancements and learn where our areas are we actually have been increasing the number of inspections. So what you say is possibly an increasing trend in the number of inspections and replacement. I look at it as good management of the program to, one, understand where the vulnerabilities are and ensure they get monitored prior to having failures. If you look at our failure rate I'm sure that would show you it had favorable results for the station.

CHAIRMAN SHACK: Okay. There's another one that was kind of curious and it says, you know, no preventive or mitigative measures are directly -- the FAC program. The program considers water treatment changes that may affect FAC rates. For example, water treatment amines, hydrogen water chemistry, hydrogen addition, or any change that might affect the pH or dissolved oxygen concentration. What systems do you use amines and hydrazine in?

MR. KELLY: I think I'd like to ask Greg Sprissler of our chemistry department to address that question, please.

MR. SPRISSLER: Greg Sprissler. I'm with the chemistry department at Limerick Station. We are currently not using any amines for treating chemicals at Limerick Station.

CHAIRMAN SHACK: Yes, that's sort of what I figured. It just seemed like a curious statement. Okay.

The next question is on fatigue. And you've got an environmental cumulative usage factor for one system, reactor water cleanup -- I like this number -- 0.9990. It's certainly less than 1.

You're crediting there the reduction in the number of cycles. Does that also include a finite element analysis to get the stresses down, or is that with a sort of a classic code type conservative stress number?

MR. KELLY: It was a classic code type approach.

CHAIRMAN SHACK: Okay.

MR. KELLY: We didn't do finite elements but we have additional information in the corrective action process where we're going to address that with a more refined analysis. And that's actually underway and working in the corrective action process.

CHAIRMAN SHACK: Okay. Then just another question. You had some cracking in your core shroud welds on both units. Just how much cracking are we talking about here? Feet, inches, kilometers?

MR. KELLY: I'll field it initially and then I'll ask our engineer to come up. But we've examined all the horizontal and vertical welds at this point and we do see cracking in most of those welds. In some of them it's more than 10 percent of the inspected length and so that puts you on an increased inspection schedule.

Most of those cracks are considered quite shallow and the hydrogen water chemistry appears to be effective. And we'll continue to examine it per the BWRVIP guidelines and you know, do the appropriate structural integrity analyses to make sure we have adequate margin for the shroud.

MR. BARTON: Do you have any mechanical restraints on your core shrouds?

MR. KELLY: No, none. We did not put any fixes in, John. No tie rods or anything like that.

MR. BARTON: I got it.

MR. KELLY: No repairs.

CHAIRMAN SHACK: Is that material 304-LM?

MR. KELLY: I'd like to ask Michelle Karasek, our vessel internals engineer, to address that question. Michelle, the question is about the material type of the shroud.

MS. KARASEK: Hello, this is Michelle Karasek, Limerick site RPV internals program owner. It is 304-L.

CHAIRMAN SHACK: 304-L.

MS. KARASEK: Yes.

CHAIRMAN SHACK: And the weld metal?

MS. KARASEK: I don't have that information.

CHAIRMAN SHACK: But the cracking is in the base metal typically.

MS. KARASEK: That's correct. It's in the heat-affected zones.

CHAIRMAN SHACK: In the heat-affected zones.

MS. KARASEK: That's correct.

CHAIRMAN SHACK: But even in the 304-L welds.

MS. KARASEK: Yes.

CHAIRMAN SHACK: Okay.

MR. BARTON: Are you through with core shroud? Let's jump from core shroud to steam dryers. I noticed you've got some steam dryer issues that you've found during inspections. What's the current status of your steam dryers in both units?

MR. KELLY: Michelle, could you please address that question?

MS. KARASEK: This is Michelle Karasek from Limerick site RPV internals program engineer. We have extensively inspected the core shroud -- I'm sorry, the steam dryer on both units in accordance with GE SILs and the VIP-139. We completed all baseline inspections.

We do have some minor IGSCC cracking

mostly in the support ring. There are a few hood seam weld indications that are also IGSCC and one fatigue flaw in a hood seam weld that has relieved itself and is not showing any signs of new or changed in growth.

MR. BARTON: So you're nowhere near talking about steam dryer replacements I take it.

MS. KARASEK: No, we're not talking about steam dryer replacements. I know it's on as a proposal if we go to EPU. That is something that is being looked at and evaluated.

MR. BARTON: Thank you.

MEMBER STETKAR: Bill, are we going to try to get all of the peripheral things out of the way first?

CHAIRMAN SHACK: Yes. I assume once we get into the liner that will probably.

MEMBER STETKAR: If so I've got a couple of questions, one on buried pipe. And the RHR service water and essential whatever you call it, ESW system. I got confused as I was reading back and forth among the LRA and RAIs and SER and all of those abbreviations. Are you going to do internal inspections of the buried safety-related service water piping?

MR. DORAN: We are going to perform

inspections of that piping. We are currently in progress of replacing large-bore RHR service water piping in our pipe tunnel.

As we remove that piping it will provide an opportunity which we will take advantage of to send an inspection method down and inspect the internals of the large-bore underground piping.

MEMBER STETKAR: Okay. Are you going to be doing -- that's fine, but the period of extended operation is a ways in the future. Are you going to be doing periodic inspections, internal inspections of that piping during the period of extended operation?

MR. DORAN: We do not have plans at this time to do that. If the opportunity presents itself.

MR. GALLAGHER: But we added a commitment to do the inspection when accessible.

MEMBER STETKAR: But isn't that inconsistent with Rev 2 of the GALL report that says if you've had indications of leakage or problems you're supposed to do something like a 5-year periodic inspection of 25 percent of the piping or something like that?

MR. GALLAGHER: For external?

MEMBER STETKAR: Internal.

MR. GALLAGHER: For internal? No, we're

consistent with the GALL.

MEMBER STETKAR: Okay. I guess we'll ask the staff about that. Take that as a heads up. No, I'll wait till you get up so that we can get to the applicant's presentation.

One other question. On the closed cooling water systems there's a statement made that they're not susceptible to stress corrosion cracking because the temperatures are below 60 degrees C. That sounds fairly low. I mean some of those systems, they're diesel generator cooling water systems, they are recirc pump cooling water. Are the outlet temperatures uniformly below 60 degrees C on all of those closed cooling water lines?

MR. KELLY: I'd like to ask Mark Miller of our license renewal project team to address that question, please.

MEMBER STETKAR: It seemed a rather modest temperature to me.

MR. MILLER: Mark Miller, Exelon license renewal. The portions of the system that have stainless steel are less than 140 degrees Fahrenheit. There are portions in the system that exceed 140 degrees but there is no stainless steel material in those portions.

MEMBER STETKAR: Okay, thank you.

MR. BARTON: I've got a couple more if you want to take the time now, Bill. Closed treated water systems. In early 2009, January 2009 and again in November you had some problems with the turbine closure cooling water system. You had high consumption of the chemicals from that system and turned it over to a system engineer for the root cause and that's where the story ends in the documents I was reading.

In November then you had an increasing trend in nitrate concentration in that same system. Now, can somebody explain what was going on in that system and has that problem been resolved?

MR. KELLY: Yes, I would like to have Greg Sprissler of the chemistry department address that, please.

MR. SPRISSLER: Greg Sprissler from the Limerick chemistry department. That was a TBCW system. It was identified by our chemistry analysis, sampling analysis program. We were making frequent adds of sodium nitrate and copper corrosion inhibitor to the system. It was documented in our CAP system.

It was given to engineering for evaluation. At first they thought it was air and leakage but that did not follow through because of the copper corrosion inhibitor was not being -- was being affected also.

It was determined by engineering that it was a leakage. I don't have details on how the system was repaired, where the leak was found, how it was repaired but I can tell you that the system is very stable now. We have not made sodium nitrate adds since 2010 and we have not made a copper corrosion inhibitor add since 2011.

MR. BARTON: Okay, thank you. In the bolting -- this goes to one of your aging management programs, your bolting integrity program. In the literature I went through I noticed there was a lot of examples of loose connections resulting from improper tightening of mechanical connections throughout the documents. And that's more than I would expect. That's more than I've seen in a lot of other plants.

My question there is did you recognize that? Did it require additional training and maintenance or what? Because it was an awful lot of, you know, non-torque loosening and it just seemed like there was a problem there somewhere in your system. Has that -- have you tackled that? Has that been resolved?

MR. KELLY: It has. I'd like to ask Ron Hess of the project team to address that question. I think he has the details on this.

MR. HESS: My name is Ron Hess. I'm with the Limerick license renewal team. Those events did result in enhancements to our training program. First of all, specifically some of those related to the use and application of hydraulic torque. So that was specific training that was instituted for maintenance personnel using hydraulic torque wrenches. And also our continuing training includes modules for maintenance personnel on bolting connections. And those were enhanced as well to include the OE from those events.

MR. BARTON: Thank you. And looking at the application and scoping I was confused here. Section 2.4 talked about screening of structures. The auxiliary water pipe tunnel which is located under the auxiliary water enclosure houses safety-related piping and is in scope for license renewal.

And a couple of paragraphs later it says the lube oil storage enclosure is located above below-grade piping tunnel that contains safety-related piping. However, I couldn't find that this lube oil storage -- that this was in scope.

Can somebody explain that? It seems like they're both over an enclosure that's got safety-related piping yet one's in scope and the other is not. Lube oil storage enclosure is not included in scope and yet the auxiliary water tunnel located under the auxiliary water enclosure is in scope. So I don't understand what's going on here.

MR. GALLAGHER: We had received an RAI on that also and had some clarity so maybe we can have Dave Clohecy. Can you please give us the info on that?

MR. CLOHECY: My name is Dave Clohecy and I'm a member of the Exelon license renewal team. We revised the LRA in response to an RAI. We clarified in that response that the non-safety related aux boiler enclosure and the non-safety related aux boiler pipe tunnel were both in scope because they were immediately adjacent to the reactor enclosure which is safety-related. We also clarified that the lube oil structure is not in scope because it is not immediately adjacent to the reactor enclosure.

MR. BARTON: Okay, thank you.

CHAIRMAN SHACK: Just do you currently have a hardened vent for your wet well?

MR. GALLAGHER: No, we do not.

CHAIRMAN SHACK: So that will be something you'll be considering? I know that your most beneficial SAMDA was an ATWS vent. Would you consider making your hardened vent larger than the 1 percent sort of decay heat level vent that most plants are considering?

MR. GALLAGHER: I don't know what we're considering, Dr. Shack, on that but we're heavily involved with the industry initiatives and we'll put the appropriate size hardened vent in in accordance with the orders.

MR. BARTON: I've got one more. Inspection of water control structures. Your program is to monitor all water chemistry inside every 5 years and your program was enhanced to do that. What's your current frequency and why did you increase it to every 5 years? Is there something going on in your groundwater that's indicating it's getting aggressive or something?

MR. KELLY: I believe the answer is no but I think I'd like to have Dave Clohecy answer that question if he can.

MR. CLOHECY: My name is Dave Clohecy and I'm a member of the Exelon license renewal team. Our groundwater, a few wells have tested with chloride that is a little higher than we would like. However, the groundwater is below the level of the safety-related structures and we are monitoring the sub-drainage sump head as a leading indicator of the concrete condition.

MR. GALLAGHER: So I think we went to the 5 years just to be consistent with GALL.

MR. CLOHECY: Yes, that's correct. The GALL requires that 5-year monitoring so we are doing that at 5 years per the GALL.

MR. BARTON: That's it. The only other questions I've got are on the liner. We're going to get to that.

MR. GALLAGHER: We can continue on.

MR. KELLY: Okay, slide 7 then. There are two open items in the Limerick SER. Slide 8, please.

The first open item involves aging management of the suppression pool liner. The NRC staff is requesting more information in four main areas: our prioritized approach to implementation of the coating maintenance plan, the method utilized for examination of the coating underwater, the expected corrosion mechanism present in the suppression pools, and the incorporation of acceptance criteria for downcomer examinations into aging management procedures.

We will provide background information on the suppression pool and we will address the four areas where the NRC staff is requesting more information in our presentation. The additional information to address this open item will be submitted to the NRC staff for their review.

The second open item involves operating experience for aging management programs. The staff's question relates to the review of aging management related operating experience in the period between the issuance of the renewed licensee and the implementation of our operating experience program enhancements which we've committed to enhance within 2 years following issuance of the renewed licenses.

Exelon will conduct appropriate operating experience reviews to close this gap. Additional information will be submitted to the NRC staff for their review. This completes our discussion of the operating experience open item.

I will now turn the presentation over to Mark DiRado --

MEMBER POWERS: Can I ask you a question about your coating material. That's a sacrificial zinc?

MR. KELLY: Yes. Inorganic zinc.

MEMBER POWERS: What is it really?

MR. KELLY: I'm not sure I understand your question. Can you repeat it, Dr. Powers?

MEMBER POWERS: Well, we know it's not just zinc that you put on it. What else does it have in it?

MR. GALLAGHER: Mark Miller, it's a question about the coating system, the present coating system. Do you have the details of that?

MR. MILLER: Mark Miller, Exelon license renewal. The question is what other constituents are within the zinc coating?

MEMBER POWERS: Yes, like zinc chromate or something like that.

MR. MILLER: I don't have the information on that.

MR. GALLAGHER: It was the original coating system in the plant.

MR. MILLER: I can tell you that it's a carbozinc and a Dimetcote.

MEMBER POWERS: In that case I know what it is. Thank you.

MEMBER SKILLMAN: Gene, I'd like to ask you a question, please. In the second open item we are talking in this room today about granting an extension that will become effective 20 years from now. This open item is asking why operating experience won't be factored in until 2 years after that future 20-year period begins.

MR. KELLY: Actually it's 2 years after issuance of the licenses, not when the PEO begins, Mr. Skillman.

MR. GALLAGHER: Yes, the issue was that the staff guidance in the ISG says to institute your enhancements to get to the operating experience program immediately upon receipt of the license. We said that we wanted a 2-year transition because we want to implement the enhancements fleet-wide.

The basis for that was our existing program is very, very robust. I mean our whole application is built on our existing program so we think the existing program in itself is good.

But with that we are enhancing the program. We're going to do it fleet-wide. And then the staff had asked for what, in this transition period what are you going to do. And so we're going to address that also. So we're putting these enhancements in fleet-wide and for Limerick at least 10 years before the PEO. So it's pretty much meeting.

MEMBER SKILLMAN: Thank you, that clarification helps. It surprises me that the wording isn't worded that way such that what you're really communicating is we will make sure that we've got the operating experience well embedded many years before the PEO.

MR. GALLAGHER: And that's our intent.

MEMBER SKILLMAN: Thank you.

MR. GALLAGHER: Okay, Gene.

MR. KELLY: Okay, so Mark I'll turn it over to you. And Mark will discuss the suppression pool.

MR. GALLAGHER: Yes, so this is our main part of our presentation. We're going to go into the details, background and details of the suppression pool. So, open-ended questions you have, that's this period.

Mark?

MR. DIRADO: Thank you. Slide 9, please. Good morning. My name is Mark DiRado and I'm the engineering programs manager at Limerick. First I will summarize some key points about our suppression pool. I will then address those in detail on the subsequent slides. Slide 10, please.

The Limerick primary containment is a

robust Mark II design. It incorporates a 6-foot to 8-foot thick reinforced concrete containment and a 250 mil thick metal leakage barrier. The liner is twice as thick as needed to withstand design loads.

Excellent water chemistry in the suppression pool in combination with a normally inverted suppression pool airspace results in a low general corrosion rate.

The material condition of the liner has been thoroughly characterized as part of ASME code inspections and the material condition is therefore well understood.

MEMBER SKILLMAN: Mark, would you explain that a little more thoroughly please? How is it documented? How long has the material condition been examined? What level of confidence should we have that that statement is thoroughly accurate?

MR. DIRADO: We have a very high level of confidence in the water condition, the inspections being performed and the documentation of the results. Each inspection that's performed is done by professional divers using calibrated instruments underwater. Those are documented in the results and they are reviewed by the station after each subsequent outage. The data is collected and reviewed by engineering to validate corrosion rates, trends and factor into future re-coating or repair plans.

MR. GALLAGHER: And Mr. Skillman, we're going to go into this in a lot of detail. It's actually on slide 21 where we go into the inspections.

And one point we wanted to make up front is we have -- are transitioning from an inspection program to a comprehensive aging management program. And we feel we're doing this early, you know, because like we said we're 12 years away from PEO. So you know, as you know IWE only came in play in like the year 2000 so there's only been a couple of inspections in accordance with IWE.

We instituted the aging management program for Unit 1 as we started the last outage so we say we thoroughly characterized it. For Unit 1 we have done a complete survey inspection of the suppression pool and we're going to present to you a summary of the information here in this presentation. And we'll tell you how -- that we take that data and why we're very confident that we can identify the areas that require attention in the coating system.

MEMBER SKILLMAN: Thank you.

MR. DIRADO: Exelon is committed to an aggressive aging management program. This will be begun well in advance of the period of extended operation. And we'll ensure that the suppression pool liner's intended function is maintained throughout the period of extended operation. Slide 11, please.

The Limerick Mark II primary containment design is shown in the diagram on this slide. Primary containment consists of a drywell and a suppression pool. A slab separates the upper and lower sections of containment. The continuous carbon steel liner which is shown in the blue color on the slide functions as a leakage barrier. The suppression pool is situated below the drywell.

Downcomers provide a direct path to the water in the suppression pool. That's for uncondensed steam from the drywell during the design basis event. Slide 12, please.

The suppression pool has a continuous carbon steel liner. It's coated with inorganic zinc. The liner is 250 mils thick and functions as a leakage barrier for the reinforced concrete containment structure. The strength of the containment is derived from the 6-foot to 8-foot thick reinforced concrete.

The liner has 100 percent thickness margin. In that 125 mils of general or large area thickness is required for liner structural integrity.

A minimum local area thickness of 62.5 mils is required for structural integrity of the liner. This means that flaws less than 2.5 inches in diameter and up to 187.5 mils in depth could be tolerated. Slide 13, please.

I will now describe the original coating system applied to the suppression pool liner and its intended function. The continuous carbon steel liner is a service level 1 inorganic zinc sacrificial coating.

MR. BARTON: Excuse me. What's the life of this coating? The useful life. I mean you're using this coating maybe 20-25 years or pick a number. Do you know what the useful life of this coating is? What's the vendor say is the useful life of this?

MR. GALLAGHER: Well the vendor, they'll give you a short number. Basically --

MR. BARTON: What's their short number?

MR. GALLAGHER: Well, I think we had an IR that said like 15 years or something like that.

MR. BARTON: Yes, that's what I was thinking.

MR. GALLAGHER: But really the life of the coating is sustained by the implementation of the coating maintenance plan. That's what we're proposing in this aging management program. Basically you touch up the coating and the coating with good chemistry, water chemistry, the type of water that's in the suppression pool you can maintain the coating system for a long, long time. So there's really no such thing as, you know, a specific service life. It's maintained by the coating maintenance.

MR. BARTON: The only reason I'm asking that is been there and done that. You probably know about this, right? You were there.

MR. GALLAGHER: Right, right.

MR. BARTON: We had suppression pool with -- it had some kind of, I don't know, zinc something coating. Life 20-25 years. Well, before that time it got so bad the coating maintenance program did not work and we ended up with complete re-coating of suppression pool liner. And I'm just wondering if that's -- I don't mean to interrupt your presentation but you know, eventually we gave up and had to completely re-coat it.

MR. GALLAGHER: Yes, and that's always a possibility. I think we, you know, like I said we transitioned from an inspection program to an aging management program. I think at the right point definitely when you look at our data on Unit 2, Unit

2 is very, very, you know minor. Unit 1 we have a little bit of catchup to do. But I think you'll see that, you know, I think we got it at the right point. We can get into a good coating maintenance plan.

MR. BARTON: Okay.

CHAIRMAN SHACK: But I mean, just coming back to John's point. The material in your environment is really the same as a Mark I containment. I mean you know they're different containment designs but the corrosion problem is similar. And we sort of know the older Mark Is certainly have coating problems. It's just hard for me at least to understand why you're going to be any different than those plants are.

MR. BARTON: That's where I was coming from.

MR. GALLAGHER: And we recognize that because we have plants of those vintage also. And we know the -- and we'll get into the presentation, but the larger implications of say replacing your coating system. There's a lot of issues with that. Obviously you have to offload the core, you have to -- in that outage you have to reduce the ECCS inventory during that outage. There's radiological issues, industrial safety issues. In fact, we're going through that at one of our plants that we're in process on. So we think that if we can do this early we can maintain the system.

And then, however, we'll get into showing you our commitment. The commitment is clear, we have to meet the criteria going into the period of extended operation. So, if the only way to do it is to replace the system then that's what we'd have to do.

CHAIRMAN SHACK: The focus here is on structural function. There's also the Generic Letter 9804 kind of thing of preventing particulate products and stuff. There are places you seem to have lost a lot of coating that, you know, you may not be getting a structural limit but I assume that you're generating particulate at a fairly good clip.

Both of these have to be met and that was one of the things that was confusing to me, that you say you're meeting the XI S8 protective coating thing which is sort of an ASME, or an ASTM kind of thing to I think look at it as a 98-04 kind of a problem. And then you're off here in IWE space looking at it as a structural problem.

Are both of those consistent? Is one more limiting than the other?

MR. GALLAGHER: Yes, and actually this is where we're talking about what the intended function is of the coating system, the present coating system.

MR. GALLAGHER: Well, you made it inorganic zinc for some reason.

MR. GALLAGHER: Yes, and the reason, just like you said Dr. Shack, is that the -- you know, you balance the two issues, asset protection and not clogging the suction strainers for ECCS. So this coating system was actually picked because it kind of dissolves. It doesn't cause problems with clogging of the suction strainers.

CHAIRMAN SHACK: Well, but that's the adhesion of the film. What I'm worried about is that you're getting corrosion products.

MR. GALLAGHER: Yes, and part of our aging management program is to de-sludge, clean up the suppression pool every outage. And that's part of our commitment to -- and when we do that, let's see, Ron Hess, Ron, how much particulate corrosion products do we remove each outage now?

MR. HESS: Okay, Ron Hess, Limerick license renewal team. Typically on a yearly basis we generate about 100 pounds of material that is then removed during our de-sludging operations during routine outages.

MR. GALLAGHER: So it's not really that much and the suction strainers are huge.

MR. BARTON: One hundred pounds?

CHAIRMAN SHACK: Yes, I was going to say we'll have Sanjoy come in and talk to you about 100 pounds of particulate.

MEMBER STETKAR: That's 100 pounds under for all practical purposes stagnant conditions. No blowdown forces, no --

MR. KELLY: Correct.

MEMBER STETKAR: -- nothing deciding to dislodge a lot of other material.

MR. GALLAGHER: Yes, it's the corrosion products from -- that's in the piping system.

MR. KELLY: And it's a very -- Dr. Shack, a very small fraction of the design loading of those new strainers. They're much bigger and can accommodate quite a bit more than that.

MR. HESS: Yes, if you want me to add some information, our design requirements for the ECCS suction strainers include things like 900 cubic feet of insulation, 1,000 pounds of sludge, 150 pounds of miscellaneous dust and dirt, another 50 pounds of corrosion products.

And so from a design basis standpoint the loading on the strainers from material that we remove each de-sludging operation is far more than what the strainers are designed to accommodate.

CHAIRMAN SHACK: Is that based on full-scale testing of thin bed effects?

MR. HESS: That's --

(Laughter)

MEMBER POWERS: Just say no.

MEMBER SKILLMAN: That sounds like a small number and we're laughing because maybe it is but you know, a 40-pound plate, steel, 1 square foot and 1-inch thick is 40 pounds. That's 2 and a half square feet of steel -- if it's iron? Fighting its way out of your system into sludge, if it's iron.

That's not really inconsequential. Think about it. You might say well there are an awful lot of square feet. Well, I'm not sure that gives me any comfort. Most of the square feet are probably covered with your inorganic coating. I'm concerned about all the stuff you can't see that's wasting away.

MR. GALLAGHER: Most of the corrosion products are coming from the piping systems which are attached, not from the system itself. When you see the -- not from the liners. When you see the coating coverage right now we have about 85 percent of the coating still intact on Unit 1, 96 percent on Unit 2. So, it's relatively, you know, a small area that's affected by the --

(Laughter)

CHAIRMAN SHACK: It's square feet. That's probably not so insignificant.

MEMBER SKILLMAN: That's what I think. I mean if you really make it thin you'd say golly, that could be a lot of stuff.

MR. GALLAGHER: What I'm saying is the corrosion products are not predominantly coming from the liner, they're coming from the piping system.

MEMBER SKILLMAN: I got it.

MR. GALLAGHER: Okay, so Mark, why don't we start with this slide again on --

MR. DIRADO: Sure.

MR. GALLAGHER: There's some key points here we wanted to make sure.

MR. DIRADO: Okay. As stated previously, the continuous carbon steel liner has a service level 1 inorganic zinc sacrificial coating.

The coating was applied to the liner with a 6 to 8 mil dry film thickness. The intended function of the coating is to maintain adhesion so as to not adversely affect the ECCS strainers by clogging. The coating --

CHAIRMAN SHACK: If that was its intended function you wouldn't put it on.

MR. GALLAGHER: It's intended function is because that's the safety-related function of the coating system is to prevent clogging of safety-related ECCS systems.

MR. DIRADO: Right. We --

MR. GALLAGHER: We have it on there --

CHAIRMAN SHACK: Okay, but not only by maintaining adhesion but also by reducing corrosion product development.

MR. DIRADO: It's probably a combination but you know, in effect it was to make sure that you don't have flaking of your coating from, you know, post accident that would go onto your suction strainers and clog it.

MR. DIRADO: We view the coating system as a design feature that assists in asset protection.

CHAIRMAN SHACK: You mean you put this on just to make sure it wouldn't flake off?

MEMBER POWERS: I mean that makes no sense at all.

MR. GALLAGHER: We put it on for asset protection.

MEMBER POWERS: To make sure it didn't fall off.

MR. GALLAGHER: The safety-related function is so it doesn't affect the safety-related systems.

MEMBER POWERS: You put it on so you don't corrode your steel.

MR. GALLAGHER: For asset protection.

MEMBER POWERS: And when you do your inspection the only vehicle you have to tell that it's failing to meet this adhesion is to see it flaking off, is that right?

MR. GALLAGHER: Visual, yes.

MEMBER POWERS: You don't have a good mechanism to tell us when these things are getting old and we're losing the hydroxyl bonding?

MR. GALLAGHER: Actually, we do dry film thickness measurements and we'll talk to you about that in the inspection slide. You can see how thick the coating is remaining.

MEMBER POWERS: You get the thickness but you don't know anything about the adhesion to the surface other than --

MR. GALLAGHER: Yes, that would just be --

MR. BARTON: Unless you see a lot of

bubbles when you're doing it.

MEMBER POWERS: Yes, I mean it's just a visual thing. It's the only thing we have.

CHAIRMAN SHACK: Don't some of the ASTM requirements have adhesion tests?

MR. GALLAGHER: I think when you apply the coating.

CHAIRMAN SHACK: Apply the coating.

MR. GALLAGHER: But not when you're --

MEMBER POWERS: What we know is that as these materials age you start developing a carbon yield signal when you do an infrared spectrum monitor. And I suspect it's the anolic hydroxide is changing into a carbonyl group. But I don't know that for a fact.

I know only the empirical observation but we've just never developed an instrument that you could take in and run over the coating and say oh, it's getting bad here and it will start flaking off five outages from now. I mean we just don't have that.

Anecdotally, I asked the Air Force how they knew when to change -- when to paint their airplanes. And the guy told me we have invested millions of dollars in academic research in this. But in the end some sergeant goes out, looks at it and decides whether to paint it or not. There are lots of devices out there but nobody uses them. It's just unfortunate. I mean the only thing you can do is you look at it.

MR. GALLAGHER: We'll get into our visual inspection methods in subsequent slides. We'll tell you how we do that. Okay? Mark.

MR. DIRADO: Thank you. The service life of the inorganic zinc coating is sustained by implementation of our coating maintenance plan. Frequent full ASME exams, spot re-coating, protective large area re-coats and frequent cleaning of the suppression pool and removal of sludge sustain the service life of this coating system.

MEMBER SKILLMAN: Mark, how do you know your coating maintenance plan and program are robust and effective? If it's your protection how do you know it's working for you?

MR. DIRADO: We -- for effectiveness of the plan each inspection that's done in review has a documented engineering evaluation that follows it to validate a number of specific factors that will weigh into either augmentation or moving up of the re-coating or additional methods to, corrective maintenance to maintain the liner appropriately.

MEMBER SKILLMAN: How do you weave operating experience into that?

MR. DIRADO: The operating experience is gathered for each coating application. It's discussed in or prior to coating work. Each outage there's a set of meetings that are held that will factor that in. We use industry experts that factor in operating experience from the past and bring those to the station. We leverage INPO and other outside sources for that, plus we have a large fleet where operating experience for coating maintenance is leveraged as well.

MEMBER SKILLMAN: Thank you, Mark.

MR. BARTON: Who does this work? Is this contracted out each outage?

MR. DIRADO: Yes.

MR. BARTON: And who does the inspection of the contractor's work?

MR. DIRADO: The contract organization currently is UCC.

MR. BARTON: They do their own? The plant doesn't go and look, inspect the work that's done in the liner in the outage?

MR. GALLAGHER: We have an underwater

construction company. It's a diving outfit because it's done underwater. And they will do the inspections.

MR. BARTON: They do the work and inspect their own work?

MR. GALLAGHER: And they would do the coating. And so you know, it's all done in accordance with their inspection procedures.

MR. BARTON: But you never go and check?

MR. GALLAGHER: Well, we have --

MR. BARTON: The guy does the work and inspects it and turns in some paperwork. But do you ever double-check?

MR. GALLAGHER: With our own diving folks? No.

MR. BARTON: You don't.

MR. GALLAGHER: There's some oversight that occurs by video, you know, and that type of thing, but they have a QA program in accordance with their quality assurance program. We verify that they meet all those requirements.

MR. BARTON: Okay.

MEMBER BROWN: So they do the work and then they tell you they did it right.

MR. BARTON: Yes, exactly.

MR. GALLAGHER: Well, there is oversight. I mean, you know, they're on video the entire time.

MEMBER BROWN: I heard the video part but I didn't understand it. They've got a camera and you've got somebody off --

MR. GALLAGHER: Yes.

MEMBER BROWN: -- sitting up there looking at what they're looking at so you can see that they spot a bubble or they spot an area or they take a measurement or whatever they do underwater?

MR. GALLAGHER: There's some oversight just because they're on video the entire time. But you know, the company.

MEMBER BROWN: Watching guys float around underwater, you know, just trying to get a picture of how you get a feel for whether their inspection is actually effective or not other than them telling you that it is. That's -- I'm just following up on that.

MR. BARTON: Yes, well that's my concern. You know, there's nobody from the plant that goes and actually looks at what did this guy do and the paperwork he turned in, does it really -- is it really what happened.

MEMBER BROWN: Auditing the papers.

MR. BARTON: You know, and I'm not saying you have a dishonest contractor, I'm just saying you know at some point you go check his work and that's my concern. You're not doing that.

MR. KELLY: We have him here today and he's going to address that in a later slide. But I think I'd like to ask our program owner, George Buduck, to step up and maybe address this. George is the ISI engineer at Limerick and George is responsible to implement this program including the oversight of those vendors. So George, you might want to address the question of oversight.

MR. BUDUCK: George Buduck, the Limerick ISI program owner. We do not review their inspections. We don't specifically have divers that go in and take a look at it to verify the readings are accurate. We don't do anything like that.

CHAIRMAN SHACK: Do you get to see closeup video of the surfaces?

MR. BUDUCK: There are some videos that we do look at. We do have a picture that we will show later on.

CHAIRMAN SHACK: Yes, I mean I saw that picture. The question is really how much of that inspection you're actually able to monitor with the video or is it just a picture of a, you know, a region. Or is it, you know, somebody really is actually sort of looking at this inspection.

MR. BARTON: You know, somebody is sitting there watching this video while the guy's doing the work. Is somebody from the site actually sitting there watching that? Or is it a copy of his film or something he gives you? I'm a little nervous about your oversight of the work that's being done.

MR. GALLAGHER: The oversight we do do is there is a live video that's occurring during the outage. And we have people that can look at the video and do. I'm not saying we're there the entire time but there is some oversight. And we verify that the contractor is doing his work in accordance with the contract.

But this work is underwater and we are not there with him underwater but he is -- and we have Mark Marquis. Where's Mark? Mark, come up to the microphone, please. Mark is our underwater construction contractor. So Mark, maybe you can give us some more insight on this and our oversight.

MR. MARQUIS: Mark Marquis, Underwater Construction Corporation. During any given inspection we have video monitors with -- that are relaying pictures right from the diver's helmet at any given time.

We are I'll say subject to I'll call it a spot audit or whatever by plant QC, et cetera. Whether or not they come down is certainly to the utility's discretion. So, it's always being played back, it's always there. A live feed is always there available at any given time for anybody to watch over our shoulder.

MEMBER BROWN: How clear is the video?

MR. MARQUIS: The video is --

MR. BARTON: The water's moving when these guys are --

MR. MARQUIS: Yes, the water --

MR. BARTON: That creates refraction and everything else.

MR. MARQUIS: It's -- water clarity is, you know, we have sufficient visibility to conduct the inspection. Generally it's greater than 12 inches, less than 48 for the most part in general.

MR. GALLAGHER: And we have some pictures here we can show you. And they're right from the video that the diver is -- from his helmet cam.

MEMBER BROWN: But the diver's using his -- Mark's eyeball. It's a clarity. In other words, he's got to be right up against the wall effectively to tell any condition.

MR. GALLAGHER: And that is the inspection. So he's a qualified inspector, you know, has a level 2 inspection criteria. Mark's a level 3. And you know, they're doing it in accordance with approved procedures and a QA plan.

MR. DIRADO: And if I could just add, for the inspections when we do conduct these during the outages there is a dedicated site team that works with the underwater coating inspectors. They're reviewed on a shift basis. If there's any questions that are brought up or challenges that come from engineering they're provided directly to the team. We've never had an issue with going back out and re-looking or clarifying an issue that we have.

And as far as general oversight the divers are in communication with that team during the work. There is Exelon personnel provided during the coating inspection activities. And they're there to answer any possible questions or challenges or questions that may come up during the course of the coating activity.

If I can continue we'll go onto slide 14. Thank you. The suppression pool water quality is excellent. It meets the BWR VIP-190 EPRI water chemistry guidelines. The water is nearly a neutral pH and normally below 90 degrees Fahrenheit where low general corrosion rates are expected.

There exists only trace amounts of chlorides less than or equal to 2 parts per billion which is 2 orders of magnitude below the recommended limit. Sulfates average less than or equal to 13 parts per billion.

Primary containment is normally inerted with nitrogen. So a little dissolved oxygen is present and available to drive corrosion. The general corrosion rate in the Limerick suppression pool is less than 2 mils per year and this value has been confirmed by data taken from evaluation grids which are monitored in the suppression pool on each unit.

One area that the NRC staff requested more information is the expected corrosion mechanism in the suppression pool. I will now turn the presentation over to Barry Gordon who will discuss this issue.

MR. GORDON: Thank you, Mark. General corrosion of carbon steel is the predominant corrosion mechanism expected at the Limerick suppression pool. Pitting corrosion is not expected in the Limerick suppression pools. When carbon steel is essentially exposed to the steel border at ambient temperatures carbon steel simply rusts. It does not pit.

This statement is supported by three main mitigating factors. First, pitting corrosion occurs in alloys that form thin nanometer protective passive films on the surface. Carbon steel does not form passive films in the low-temperature high-purity water that's observed in the Limerick suppression pool.

CHAIRMAN SHACK: Again there's an inspection report that says every floor and wall plate, every downcomer and every suppression pool column has some degree of pitting. Most of the pits and floor plates are less than 50 mils deep and there are hundreds of pits that are less than 30 mils deep.

MR. GORDON: This is misinterpretation. This is the most common, common thing I see relative to pitting. Everyone looks at -- if you look at high magnification of general corrosion you're going to see little indications that look like pits and it's just not -- it's just not pitting. It is indeed pits, but it is not the pitting mechanism.

Second, pitting of passive alloys such as stainless steel, aluminum alloys, nickel-based alloys, typically occurs in the presence of aggressive anolic species, especially chlorides. But this primary pitting agent is not present, essentially not present in the Limerick suppression pools.

MEMBER SKILLMAN: Barry, how do you know that you have identified what could be the aggressive species? You identified chlorides, sulfates. I know one case where sulfites were more aggressive than either chlorides or sulfates. Could there be other anions or cations in the suppression pool water that would be particularly aggressive right at the water?

MR. GORDON: If you had -- even if you had aggressive species present which doesn't appear to be the case you still need a material that forms a passive film. The fact that carbon steel in this environment does not form a passive film like it does in case of embedded in concrete where it does form a passive film you still wouldn't -- you have more, a higher rate of general corrosion but you wouldn't have pitting corrosion.

MEMBER SKILLMAN: Thank you.

MR. GORDON: Finally, the suppression pool environment has limited amounts of dissolved oxygen since the airspace above the water is inerted with nitrogen during operation. Dissolved oxygen is necessary to drive the corrosion process. In other words, the limited amount of cathodic reactant oxygen will mitigate all forms of corrosion in the Limerick suppression pool.

I'll now turn the presentation back to Mark DiRado who will discuss the results of IWE examinations in the suppression pools and the material condition in the liners of both units.

MEMBER POWERS: When you say that the head space is inerted with nitrogen what is the oxygen partial pressure?

MR. KELLY: I would like to ask Greg Sprissler of the chemistry department if he can address that question. Greg, did you hear the question?

MR. SPRISSLER: I did. The partial pressure of oxygen in the suppression pool, was that the question?

MEMBER POWERS: And the head space above the pressure.

MR. SPRISSLER: Greg Sprissler from the Limerick chemistry department. I do not have that information, sorry.

MEMBER POWERS: But the inertion can take that oxygen potential down below -- partial pressure down below a torr in something like that, right?

MR. GALLAGHER: The tech spec is less than 4 percent.

MEMBER POWERS: Yes, the tech spec is

nonsense, okay, because you go way below that.

MR. GALLAGHER: Yes, but that's what it's maintained, at least below 4 percent oxygen.

MEMBER POWERS: But even at 1 percent that's enough dissolved oxygen to drive corrosion, isn't it?

MR. GORDON: But a lot of the -- I mean, the oxygen will be consumed with corrosion of the zinc, you know, film and also any exposed carbon steel. Also, you know, the oxygen should be higher concentration at the surface and then it will decrease as you go down.

MEMBER POWERS: It ought to.

MR. GORDON: Yes.

MEMBER POWERS: It ought to if it's being consumed.

MR. GORDON: Yes. It's essentially de-aerated at the bottom.

MEMBER POWERS: My contention here is they can't inert it enough to totally suppress corrosion.

MR. GORDON: Right, but --

MEMBER POWERS: It's just impractical.

MR. GORDON: Yes. But again, at 90 degrees Fahrenheit you go from maybe 5 ppm to a significant, to 1 ppm or half a ppm dissolved oxygen.

MEMBER POWERS: Yes, but it's -- it's doing that because it's being consumed.

MR. GORDON: But it can't be refreshed during the operating period.

MEMBER POWERS: Sure it can.

MR. GORDON: Well, you have still a slow amount of oxygen.

MEMBER POWERS: Yes, but it's probably fast compared to the corrosion. The corrosion is only 2 mils per year.

MR. GORDON: Right.

MEMBER POWERS: The leak into their system is more oxygen than that by a lot.

MR. GALLAGHER: Yes, I think your point, Dr. Powers, is that the corrosion, even though the oxygen is low there's enough in there to sustain a corrosion rate. And I think that we would give you that but the overall environment does support about a 2 mil per year corrosion rate and that's basically what we see.

MEMBER POWERS: Yes, I mean you're inerting it, it helps, but it's not going to suppress.

CHAIRMAN SHACK: It's not going to eliminate.

MR. GORDON: No, it's mitigation. It's

not --

MR. GALLAGHER: Yes, we just want to describe the overall environment which is -- supports this 2 mil per year general corrosion rate and that's kind of the point we're trying to make.

MEMBER POWERS: Okay. I make that but you know, to appeal to inertion here. I mean inerting for these guys is inerting for combustion, okay? That's what they're looking for. It's not inerting to suppress corrosion.

MR. GALLAGHER: Right, exactly.

MEMBER STETKAR: Do you run your suppression pool cooling and cleanup system continuously, sporadically, as needed? Only during outages?

MR. DORAN: We run the suppression pool cleanup system prior to our outages to clean up the pool and on certain periodicity we run suppression pool cooling when needed for temperature.

MEMBER STETKAR: Temperature.

MR. DORAN: That's correct.

MEMBER STETKAR: Okay, thank you.

MR. DORAN: And, I'm sorry, and for surveillance testing.

MEMBER STETKAR: Oh, sure.

MR. DORAN: Surveillance testing.

MEMBER STETKAR: Thank you.

MR. DIRADO: Thank you. Slide 16, please. This slide depicts the current material condition of the Unit 1 liner using data from the 2012 refueling outage. A little bit of introduction may be necessary at this point for the data so let me walk you through the format of the graphic and how we portray this data.

The total submerged surface area affected by corrosion is graphically shown on the y axis. That's from zero to 100 percent. That's as a function of the metal liner wall loss which is zero to 190 mils. The first vertical dashed line is the 10 percent liner wall thickness value, or 25 mils. The acceptance limit for general corrosion of 125 mils is shown on the dashed vertical line.

MEMBER BROWN: Did you say coating intact was assumed to be anything greater than 190 mils? For that first column. Did I understand that or did I get that --

MR. GALLAGHER: No, just the x axis is zero to 190. The coating intact we're actually showing less than zero, meaning that there's no degradation and the coating is intact. So that first bar, that e 4.8 percent is no corrosion and the coating is intact.

MEMBER POWERS: This gives an overall view for the whole area but if we ascribe to the description of corrosion that you've just given to us it would be the area around the water line that would be most heavily corroded because that's where the oxygen concentration is the highest. So do we have one that's spatially resolved so that we know if the water line area is more displaced into the 25 to 50 than the vast majority of it?

MR. GALLAGHER: We don't have a spatial depiction in our slide set. Most of the corrosion is occurring on the floor and there's no real particular pattern to it per se if you look at it. There is some corrosion of the walls and like you said it would be, you know, in the upper part. That does occur. But most of it is on the floor.

MEMBER POWERS: If it's corroding on the floor then it's some mechanism other than this oxygen that was described to us earlier. Presumably corrosion under sludge that you're taking out.

MR. GALLAGHER: Well, yes. And there's a whole debate on, you know, what does the sludge do. Does it aid in corrosion or does it just aid in depletion of the coating system. That being said we're -- we want to make sure as part of our aging management program that we eliminate it. So we're, in our commitment we're going to take the sludge out every outage. And it's got to help, that's our view and that's the way --

MEMBER POWERS: It can't hurt.

MR. GALLAGHER: Yes, right. So, that's part of our program.

CHAIRMAN SHACK: What has your past practice been about removing sludge?

MR. GALLAGHER: It wasn't every outage and early in plant life there were several outages where it was not removed. And you know, then the ECCS suction strainer issue came up in the mid-nineties and that's when more frequent cleaning would occur. But it was not every outage. We are going to do it every outage and that's part of our aging management program commitment.

MEMBER POWERS: I guess what concerns me is that when we talked about corrosion we focused in on oxygen which manifest you need or you don't get corrosion product. But now you're telling me that this oxygen may in fact be supplied by a sludge rather than by the ambient air dissolving in your solution.

MR. GALLAGHER: Well I don't know if we're saying that but what we're, you know, we'll get into the elements of our plan that's going to be on page 23 when we get there. But basically what we're trying to say is we, you know, we think that we have a comprehensive -- we're addressing all the elements in the program. You know, keep it clean, frequent inspections, low threshold for inspection for re-coating. Start early, you know, in the plant life, transitioning from this inspection to aging management. So all those elements are included in this.

MEMBER POWERS: Put a fan in there to keep the corrosion products suspended.

MR. GALLAGHER: No, we haven't got to that point.

MEMBER STETKAR: Well, in that sense, the reason I asked earlier, does your suppression pool cleanup system take -- can it take a suction from the bottom of the pool? I mean dead bottom.

MR. DORAN: That's where it does take a suction from.

MEMBER STETKAR: Thank you. That's your fan.

(Laughter)

MEMBER POWERS: Obviously it's not enough.

MEMBER STETKAR: Well, they don't run it.

MEMBER POWERS: Oh, I see. I think a little impeller in there to keep it a little stirred up.

MR. GALLAGHER: Okay, Mark?

MR. DIRADO: So at this part of the slide we were discussing the vertical bars that are shown on the graph. The first bar that's shown in green indicates that 84.8 percent of the submerged liner surface has intact coating.

The second bar which is shown in orange indicates that 12.6 percent of the submerged liner surface is affected by general corrosion that averages in depth up to 25 mils.

The third bar which is shown in blue indicates that 2.6 percent of the liner surface is affected by general corrosion that ranges in average depth from 25 to 50 mils.

The fourth smaller bar shown in red indicates that a very small portion, 0.03 percent of the liner surface is affected by general corrosion that has an average depth between 50 and 57 mils.

The data that's on this slide indicates

that 97.4 percent of the submerged liner surface area has less than or equal to 10 percent wall loss. All of the data is well below the 125 mil large acceptance limit.

The next slide will address smaller local areas of corrosion which are less than 2.5 inches in diameter. Slide 17, please.

This graph is similar to the previous slide. Individual localized corrosion spots have been added. The graph shows that there have been a few local areas of general corrosion which is greater than 50 mils. The right-hand side y axis is the number of localized corrosion locations from zero to 30 as a function of metal loss in mils.

The corrosion locations greater than 50 mils in depth are depicted by green diamonds. The acceptance limit for local areas of general corrosion which is 187.5 mils is shown as a dashed vertical line.

The deepest single spot of 122 mils was discovered and re-coated in 2006 to arrest the loss of material. This location was re-inspected in 2010 and again in 2012 and confirms that coating remains intact and the loss of material has been arrested. This 122 mil spot is likely the result of past mechanical damage combined with general corrosion.

As can be seen from this graph few local areas of general corrosion with greater than 50 mils metal loss have been observed since underwater examinations were begun. Those locations that have been identified are well below the corrosion limit of 187.5 mils. Slide 18, please.

This slide depicts the current material condition of the Unit 2 liner using data from the 2009 refueling outage. The information on this slide is presented in a similar fashion to that on the previous slides. The colored bars on the graph depict large area corrosion as a function of metal loss.

The first bar shown in green indicates that 95.8 percent of the submerged liner surface has the coating intact. The second bar which is shown in orange indicates that 3.8 percent of the submerged liner surface is affected by general corrosion that ranges in depth up to 25 mils.

The third bar which is shown in blue indicates that a small portion, 0.04 percent, of the submerged liner surface is affected by general corrosion ranging in average depth from 25 to 50 mils. None of the Unit 2 submerged liner surface is affected by general area corrosion greater than 50 mils.

The data on this slide indicates that 99.6 percent of the liner surface area on Unit 2 has less than or equal to 10 percent wall loss. All of this data is well below the 125 mil large area acceptance limit. The next slide will address the smaller local areas of general corrosion, those less than 2.5 inches in diameter.

MR. BARTON: Unit 2 has been in operation, what, 2 years after Unit 1?

MR. GALLAGHER: It's about 5 years.

MR. BARTON: Five years?

MR. GALLAGHER: About 5 years, yes.

MEMBER SKILLMAN: So is that differential between Unit 1 and Unit 2 due almost solely to the age during which the submergence has been occurring?

MR. GALLAGHER: We think it's the age and we institute, you know, when you identify our practice is to do -- because of operating experience in Unit 1 or industry operating experience those good practices were initiated earlier, early.

MEMBER SKILLMAN: So it benefitted Unit 2.

MR. GALLAGHER: It benefitted more in Unit 2.

MEMBER SKILLMAN: I understand. Thank you.

MR. DIRADO: Slide 19, please. As with the previous slide for Unit 1 localized corrosion locations greater than 50 mils in depth on the Unit 2 liner are depicted by green diamonds. The acceptance limit of 187.5 mils is the same for both units.

Eight local areas of general corrosion have been identified on the Unit 2 liner greater than 50 mils. As can be seen by this graph of submerged liner exams very few local areas of general corrosion with greater than 50 mils metal loss have been observed since underwater examination has begun. Those locations that have been identified are well below the corrosion limit of 187.5 mils. Slide 20, please.

Now that I've described the material condition of the suppression pool liners I'll address the design features and material condition of the downcomers.

The Limerick Mark II containment has 87 downcomers, each 24 inches in diameter with a 375 mil wall thickness. The downcomer interiors are coated with epoxy. The exteriors are coated with inorganic zinc. Each downcomer is 45 feet long and the lower 11 feet are submerged. Four of the 87 downcomers, those with vacuum breakers, are capped at the bottom.

The Unit 1 downcomers were inspected in 2012, currently have less than 25 mils of wall loss. The Unit 2 downcomers were inspected in 2009. Those currently have less than 10 mils of wall loss.

The acceptance criteria for general area metal loss is 44 mils. This corresponds to a wall thickness of 331 mils required for structural integrity.

For smaller local areas the metal loss acceptance criteria is 62.5 mils. This corresponds to a wall thickness of 312.5 mils which is required for structural integrity.

The SER open item identified that these acceptance criteria should be incorporated into the procedures that are used for downcomer inspections. Exelon agrees with the NRC staff. These criteria will be incorporated into aging management inspection procedures.

Now that we have addressed the actual material condition of the suppression pool liners and downcomers and the extent of general corrosion we will next address how the ASME IWE examinations are performed.

Since we implement the coating maintenance plan by performing underwater inspections the following slide discusses details associated with that method of examination. There is an area -- this is an area where the NRC staff has requested more information on the SER open item. Slide 21, please.

This slide depicts how qualified divers perform underwater examinations and record data associated with coating depletion and metal loss.

First, personnel performing underwater inspections are qualified and certified coating inspectors. They meet the requirements of ANSI N45.2.6 and ASTM D4537. For the liner the underwater inspectors are qualified to ASNT CP-189 and meet ASME Section 11 requirements.

A 100 percent inspection is performed on accessible wall and floor plates to qualitatively assess the general condition of the coating and steel liner by performing a VT-3 visual examination.

CHAIRMAN SHACK: What does VT-3 mean in this context?

MR. DIRADO: It means that the inspectors are qualified to ASME VT-3 requirements in the performance.

CHAIRMAN SHACK: But VT-3 almost sort of means there's no loose parts laying around, right? I mean, it's -- what are you actually looking for when you say VT-3 in this context?

MR. GALLAGHER: It's a visual inspection. We have Mark Marquis. Mark, why don't you tell us about that.

MR. MARQUIS: Mark Marquis, Underwater Construction Corporation. VT-3 for the liner inspection is primarily you're looking for anything, any corrosion. You're performing a coating and corrosion assessment on the liner itself. It's not strictly for bolting or loose parts necessarily but on the liner, the welds, et cetera, and all done within -- by our program within 4 feet.

CHAIRMAN SHACK: Okay. And then how is that going to differ then from the VT-1 examination?

MR. DIRADO: I have some information on that for this slide if you let me continue or we can -- let Mark address. So, for the VT-3 the qualitative examinations, they identify and evaluate any coating discontinuities, any imperfections and also identify the complete loss of coating for an area. This is evident by the presence of corrosion as stated.

Our large surface areas then get subdivided into smaller areas as necessary to facilitate data clinician. And then describe the conditions on different regions of the plates.

The characterization of the degree of rusting is performed consistent with methods described in the ASME standard test method for evaluating the degree of rusting on painted steel surfaces.

Indications of general corrosion are entered into a data sheet by the size of area inspected and the percentage of the inspected area affected. The affected area for a plate is then calculated based on the recorded data.

For smaller local areas of general corrosion the inspector identifies the size of the area containing the indications, the size of the indications and the quantity of those indications within the area.

VT-1 or a detailed visual examination is performed for plate areas that meet the augmented requirements of ASME IWE. For the liner plate areas that exceed 25 mils general area or 50 mils local area are subject to augmented examinations.

Metal loss for such areas is quantitatively assessed for these areas using calibrated depth gauges and adjusted by measuring dry film thickness of the coating to determine the actual metal loss for each reported location.

The visual exams are supplemented by

volumetric UT in accordance with ASME IWE 3200. These supplemental exams are used when degradation would otherwise require additional technical evaluation such as conditions which would bring into question surrounding metal assumptions contained in the design flaw analyses.

Considering all these quality measures and examination techniques Exelon is confident that the underwater examinations are performed rigorously in accordance with procedures and industry standards. We are also confident that both metal loss and coating depletion will be consistently and thoroughly characterized both prior to and during the period of extended operation. Slide 22, please.

This picture provides an idea of what the liner corrosion looks like in the suppression pools. The visible area seen is approximately 1 square foot. It represents a plate surface that's affected by general corrosion that is occurring at a rate of less than 2 mils per year in the suppression pool. The estimated coating depletion on this plate is 40 percent. The average metal loss due to general corrosion is 17 mils in depth which is less than 10 percent wall thickness loss.

MR. BARTON: I'm looking at a wall? I'm

not looking at the floor here, I'm looking at a vertical? This is not the floor?

MR. GALLAGHER: This is a floor plate. A floor plate.

MR. BARTON: A floor plate?

MR. DIRADO: Sorry, I used wall thickness interchangeably with metal thickness.

MR. BARTON: Okay. I always wonder am I looking at the vertical or am I looking at the floor.

MR. DIRADO: The areas where corrosion is visible have experienced coating depletion. The unaffected areas shown still have inorganic zinc coating present which is protecting the liner surface. Slide 23, please.

This slide summarizes the enhancements made to the IWE aging management program. These enhancements represent an aggressive aging management plan begun well before the period of extended operation that will maintain coating protection and minimize liner metal loss.

First, the plan includes de-sludging the suppression pool floor each refueling outage. This frequent cleaning will minimize the potential corrosion sites.

MEMBER SKILLMAN: Mark, does this de-sludging only vacuum or does it lase, water lase so fresh surface is exposed?

MR. DIRADO: It includes vacuuming. As far as water lasing?

MR. KELLY: We can ask Mark Marquis of UCC to address that question.

MR. MARQUIS: Mark Marquis, Underwater Construction. I'm sorry, could you repeat the question?

MEMBER SKILLMAN: Yes. Is the de-sludging a vacuuming process or is it a vacuuming plus a hydrolasing process?

MR. MARQUIS: No, the de-sludging process is primarily a de-sludge vacuuming process. I'm sorry.

MEMBER SKILLMAN: Thank you. Thanks.

MR. DIRADO: Second. An ASME IWE examination is conducted each ISI period which is three times every 10 years. This is for 100 percent of the submerged liner surface. This more frequent exam schedule thoroughly characterizes the material condition of the suppression pool liner.

The frequent exams also continue to confirm the expected general corrosion rate expected for the suppression pool water environment as well as providing opportunities for re-coating.

Third, the area re-coats for general corrosion of greater than 25 mils will be performed. General corrosion occurs in the suppression pool at a rate of less than 2 mils per year. The acceptance limit for loss of material due to large area general corrosion is 125 mils metal loss.

Re-coating at 25 mils which equates to 10 percent wall thickness coupled with a frequent inspection interval of less than 4 years ensures minimal additional liner wall loss.

Fourth, spot re-coating of the local areas of general corrosion greater than 50 mils in depth will be performed.

MR. BARTON: Let me ask you something. How do you re-coat this stuff?

MR. DIRADO: The specific spot re-coatings are performed with a direct application by the divers. The larger area re-coats have a specific methodology and they're usually applied by a roller technique.

MR. BARTON: While it's underwater?

MR. DIRADO: Yes. Underwater.

MR. BARTON: And it adheres?

MR. DIRADO: That's correct. And it results in a service level 1 qualified coating.

So fourth on this slide, spot re-coating for local areas of general corrosion greater than 50 mils in depth will be performed. Pitting corrosion is not expected to occur in the suppression pool water environment.

However, even if the localized metal loss rate were hypothetically eight times larger than expected, for example, 16 mils a year, then a 50 mil spot would progress to 114 mils in depth over 4 years, and that is still well below the acceptance limit for general corrosion of 187.5 mils.

Fifth, in addition to the action levels for metal loss the plan has provisions to proactively re-coat large areas before significant corrosion occurs. For plates greater than 25 percent coating depletion the affected area will be re-coated.

Last, item 6 on the slide --

CHAIRMAN SHACK: So we would re-coat that plate we saw in the picture?

MR. GALLAGHER: Yes. So, and that's our plan. We think we've hit all the elements to have a good aging management plan and this is the key feature of being proactive. So when we have coating depletion greater than 25 percent in an area we'll -- even though the corrosion would be less than 10 percent, you know, it could be hardly anything we're going to re-coat that area. And that way we'll get ahead of this. And to Mr. Barton's point on, you know --

MR. BARTON: I'm still trying to understand this. I've got a corroded spot there. I can dab some zinc on it underwater?

MR. GALLAGHER: No, no. It's epoxy. It's an epoxy coating.

MR. BARTON: Oh, okay.

MR. GALLAGHER: And it's intended for underwater application.

MR. BARTON: And I don't have to clean this corrosion at all.

MR. GALLAGHER: Well, you have to do some surface prep. You do surface prep and then there's a coating.

MR. BARTON: On the epoxy. Okay. All right. Thank you.

MR. GALLAGHER: But that -- our intent in this part was to be proactive in getting ahead and not having significant material loss in the lining.

MR. DIRADO: Finally, for item 6 on this slide the enhancements were begun in 2012 for Unit 1 and will be initiated in 2013 for Unit 2. Early institution of the plan allows seven cycles of coating maintenance for Unit 1 and nine cycles of coating maintenance for Unit 2 prior to reaching their period of extended operation.

MEMBER SKILLMAN: Mark, where is the re-coat material successfully used?

MR. DIRADO: The re-coat material has been successfully used at other stations. I'd like to ask George Buduck to provide the specific data.

MR. BUDUCK: George Buduck, the ISI program owner. Mark Marquis would probably be better to answer that question.

MR. DIRADO: Sorry, Mark Marquis.

MR. MARQUIS: Mark Marquis, Underwater Construction. The coating material for spot applications has been used at Limerick, Peach Bottom and throughout most of the other Exelon utilities.

MEMBER SKILLMAN: Is this a product that's widely used in maritime by the Navy or by the Merchant Marines?

MR. MARQUIS: I believe that it is, yes. For use in -- the coating product has been tested and qualified for surface level 1 use as well for underwater application.

MR. GALLAGHER: And right now, Mr. Skillman, since we've just started this plan most of the coating repairs that are done have been spot coating. We have done qualification testing, mockup testing of vertical and horizontal surfaces you know in a mockup, not in the pool itself. Because what we need to do is we need to get that process down efficiently so wider areas can be done underwater. And that's what our program is doing.

That being said, you know, we want to make clear that our commitment is very clear. Prior to the period of extended operation we need to meet all this criteria. You know, the areas of greater than 25 mils re-coated, the spots greater than 50 mils re-coated, any areas greater than 25 percent depleted re-coated. So if we can't successfully get it efficiently done underwater we would have to do it in another way, i.e., drain it and do it.

And this goes back to Mr. Barton's thing. We're -- at other plants you try this, you do this and at some point you may have to do something else. That's based all on the economics, the outage timing and that type of thing. But our commitment is very clear.

MEMBER SKILLMAN: Thank you, Mike. Thank you.

MEMBER SIEBER: Has the prototype testing been performed to the extent that you were able to establish that when you apply the coating you don't trap water between the coating and the surface of the liner?

MR. GALLAGHER: Yes. We actually --

MEMBER SIEBER: How did they do that?

MR. GALLAGHER: -- just for -- maybe we can just show you a picture we did for the mockup. Let's go to slide number 43.

MEMBER SKILLMAN: I think it's a backup. We don't have that.

MR. GALLAGHER: Yes, it's a backup. And we'll show you this. This is 43, a vertical plate that was done in a mockup and then look at 44. Can we go to 44, Chris? Did a configuration of floor with various configurations. And you know, so the process is set up to be performed underwater, cleaning the application. You know, it's a multi-coat system that's applied.

MEMBER BROWN: Is it sprayed on?

MR. GALLAGHER: No, I believe it's rolled on. Mark?

MR. MARQUIS: Yes, it's not -- we got away from the roller. It's actually a pad type applicator but it's a power-fit pad applicator. That's correct.

MEMBER STETKAR: Mark, before you sit down is there any experience -- I mean, you know, these photographs show that you have some confidence that you can apply it fairly well. Is there any operating experience either from the nuclear fleet and the answer there is probably not yet, but from perhaps maritime applications if it's indeed used in maritime applications to give you confidence that indeed the coating remains intact and is effective for periods like 10 to 15 to 20 years? Is there any evidence to support that?

MR. MARQUIS: We've used this particular product in concrete, spent fuel concrete fuel basins at various utilities overseas. And we don't have a 15-year period to go by but the last -- we've been back over the last few years, but it's been in service probably 3 or 4 years now with no detrimental effects noted. Still intact.

MEMBER STETKAR: Thank you.

CHAIRMAN SHACK: But let me understand the commitment. Since you actually haven't demonstrated you can re-coat the plates yet with this process. If it turns out you're unsuccessful your commitment is basically sometime before the PEO to re-coat? Or?

MR. GALLAGHER: Yes. If you look at our

commitment it's based on this criteria. We need to meet these criteria, the 25 mils for any areas greater than 25 mils, any spots greater than 50 and any plates with greater than 25 percent loss.

If you go to our next slide on the prioritization. Is that the next slide? Yes. So, one of the questions the staff had was about how we would prioritize this. And so this is what we have and we'll go over that with you.

But essentially what I was trying to say with the commitment is this would be how we would do this. And as I said we want to do it in scheduled outages because you don't have all the other competing safety issues of draining the suppression pool, offloading the core, that type of thing.

But our commitment is clear, we need to meet these areas prior to the period of extended operation and maintain that in the period of extended operation. This is how we will maintain it in the period of extended operation.

It basically is we will re-coat these as we go and the proactive plate approach we give ourselves one inspection schedule just for some planning and scheduling. But prior to PEO all those areas need to be re-coated. And so if we can't do it underwater the way we want to with this, the way we think we can then we would have to take other action, i.e., drain it or you could do it in multiple outages. You could drain it through the walls, you know, drain it through the floor, drain it through the whole thing, whatever.

CHAIRMAN SHACK: But that plate we saw then could sort of sit that way until PEO if you couldn't successfully do it underwater.

MR. GALLAGHER: That's not our intent. Our intent is if you go back to the data slide on slide 16. So the real areas of concern, the spot re-coats are easy and those greater than 50 mils, we're going to do those and that's not a problem.

So, the issue is the greater than 25 mils, greater than 10 percent. And there's only 2.6 percent of the area. So we think we can get there definitely in this area. And if you go to the Unit 2 it was only -- go to page 19, or 18. It was only 0.4 percent. So we have those areas identified, we have -- there are just a few plates that are involved and we can go out and get those.

So the only areas that we'd be talking about would be the ones for the more proactive approach. There are a number of those areas. In Unit

1, Unit 2 there's not so much. And we think with a stepwise fashion we can get there.

And the justification is that there really is no significant degradation on those plates at this point. And but you know, again, we have to meet the criteria going into the period of extended operation.

MEMBER STETKAR: Mike, anywhere in your backup slides do you have a graphic that shows the spatial distribution of the areas where you do have greater than 25 mils loss?

MR. GALLAGHER: No.

MEMBER STETKAR: You know, a picture of vertical, horizontal surfaces that show what they are.

MR. GALLAGHER: No, Mr. Stetkar. The only thing I can show you, if we go to page 30, slide 30. This is an overview of the floor plan.

MEMBER STETKAR: Yes, that doesn't help much.

MR. GALLAGHER: Yes. So this has the plates, you can see the plates there. When we talk plates, those individual rectangles are plates. The -- you can see some of the equipment.

The only thing I can tell you is there really isn't much of a pattern but there's two --

MEMBER STETKAR: I was trying to get, you know, you have small percentages but I was trying to get a feel for area and location.

MR. GALLAGHER: Yes. So, there's three -- okay, so actually on Unit 1 for the areas greater than 25 mils there's actually two wall plates and there's two floor plates. The two floor plates are 4A and 6C. So if we can point to those, Chris. 4A is in the north -- no.

MEMBER STETKAR: Northeast corner there someplace.

MR. GALLAGHER: No, get back on the -- okay.

MEMBER STETKAR: I see that one.

MR. GALLAGHER: Four alpha and then the other was 6C. Six charlie --

MEMBER STETKAR: -- charlie is the southwest corner.

MR. GALLAGHER: Southwest corner. Okay. So, there's really no specific pattern or anything but there are the two areas on the floor. And on the wall there's 7B and 6B. They're two areas we would have to address.

MR. KELLY: But, and it would not be the entire plate, Mr. Stetkar.

MEMBER STETKAR: Yes, that's what I was

trying to get a feel for. Do you have, you know, 200 places where you have about 6 square inches that you need to coat or do you have a fairly large area.

MR. GALLAGHER: No, for these greater than 25 mil there's only these four plates on Unit 1. And then Unit 2 --

MEMBER STETKAR: Is less.

MR. GALLAGHER: Yes, Unit 2 is -- there's a couple. There's actually four plates also but two of them are very, very small areas.

CHAIRMAN SHACK: Okay, we're going to have to finish up here.

MR. GALLAGHER: Yes. Okay. If we can go to wrap up here, Mark. So, if we go to page 24 I think we covered this. Dr. Shack, in the interest of time do you want us to move forward quickly?

CHAIRMAN SHACK: Move forward.

MR. GALLAGHER: Okay. So, if you look on page 24 here this is new information we're going to be supplying the staff on how we'll be implementing the program. And the feature is basically we're -- we have to get some catchup to do on -- particularly on Unit 1 and so we have that prioritized as we have prior to PEO.

And then in PEO what we're proposing is

that we would re-coat these areas of degradation as they occur when they're discovered in the outage and then the proactive coating for the plates would be done within one scheduled period.

MEMBER SKILLMAN: Mike, in the context of the slide you identify areas, local corrosion areas, and plates. Should we interpret plate to be the geometric square?

MR. GALLAGHER: Yes, the plates where there's rectangles. And we're just saying that --

MEMBER SKILLMAN: So each of those is an identified quantity in the map of the suppression pool.

MR. GALLAGHER: Right. When we map out the suppression pool we do it by plate so we can say okay, that plate is, you know, X percent depleted of coating.

MEMBER STETKAR: So bullet 3 is communicating that if 6A plate has that or greater depletion you're going to fix the whole plate.

MR. GALLAGHER: The plate could be entirely re-coated if it was spread out. If it was in a specific area you could just do the specific area. But what we're saying is that plate would have been identified for treatment because it had at least 25 percent depletion.

MEMBER STETKAR: Thank you.

MR. GALLAGHER: And again, that depleted area is well less than -- it's less than 10 percent material loss.

So we'll just, if we can just step through to the next slide. We just wanted to summarize what the open item resolution was. We had four areas. We think we've covered those in the presentation, a prioritized approach, methods, the exam, our expected corrosion mechanism and our downcomer acceptance criteria.

And all this will be -- we have a written open item response which will be sent into the staff next week. Go to the next slide.

Mark, if you could just give us our overall summary.

MR. DIRADO: Sure. In summary the enhancements to the Limerick IWE aging management program provide reasonable assurance that the aging of the suppression pool liner will be managed appropriately. Limerick has a robust containment design with a metal liner that has 100 percent thickness margin.

The environment in the suppression pool is not conducive to pitting corrosion and water chemistry quality is excellent with respect to minimizing general corrosion.

MEMBER POWERS: Your discussion of water chemistry, you focused on inorganic species, chloride and sulfate particularly. Do you characterize the organic content of that water?

MR. GALLAGHER: Organic content? Greg, Dr. Powers has a question about organic content of the suppression pool.

MR. SPRISSLER: Greg Sprissler from Limerick chemistry. Our analysis was limited to chloride sulfate pH connectivity and TOC analysis. So with TOC we have a general characterization of organic compounds but nothing specific.

MEMBER POWERS: And what does your TOC come in at?

MR. SPRISSLER: I'm sorry, I can't hear you.

MEMBER POWERS: What level of TOC do you have?

MR. SPRISSLER: Typically we have less than 50 ppb.

MEMBER POWERS: Fifty ppb.

MR. SPRISSLER: Parts per billion.

MEMBER POWERS: Right. By mass.

MR. SPRISSLER: Yes.

MEMBER POWERS: And you just don't know what that is.

MR. SPRISSLER: That is correct.

MEMBER POWERS: Okay.

MR. DIRADO: Our low corrosion rate has been confirmed. Exelon is committed to an aggressive aging management program begun well in advance of the period of extended operation which will ensure that the intended function of the suppression pool liners are maintained throughout the period of extended operation.

I'll now turn the presentation over to Mike Gallagher for closing remarks.

MR. GALLAGHER: Okay, thanks Mark. So in conclusion we've developed a comprehensive, high-quality License Renewal Application and a robust aging management program that will ensure the continued safe operation of Limerick. Pending any questions that ends our presentation.

CHAIRMAN SHACK: Any further questions from the subcommittee?

MEMBER POWERS: Just a reminder, the water volume in your suppression pool?

MR. GALLAGHER: Water volume, I think it's about 1 million gallons.

MEMBER POWERS: 1.2 million?

MR. GALLAGHER: Dave Clohecy?

MR. CLOHECY: My name is Dave Clohecy and I'm a member of the Exelon license renewal team. The water volume in the suppression pool is approximately 1 million gallons.

CHAIRMAN SHACK: Thank you very much for an excellent presentation. We'll take a break now until 10:35. Then we'll hear from the staff.

(Whereupon, the foregoing matter went off the record at 10:19 a.m. and went back on the record at 10:35 a.m.)

CHAIRMAN SHACK: If we can come back into session Melanie Galloway will start us off again.

MS. GALLOWAY: Okay. Thank you, Dr. Shack. I've already introduced Patrick Milano. He's the Limerick project manager for the last month. Previous to his assignment as the project manager Rob Kuntz who is sitting here at the computer was the project manager who led and coordinated the project through the initial application. So he's here to assist as well.

Pat is going to be giving the whole

presentation today since there are only two open items, but there are support staff at the front table that I'd like to go ahead and introduce. To the far end of the panel there without a name tag is Dr. Allen Hiser who's our senior-level advisor on materials and degradation in the division. Abdul Sheikh is a senior structural engineer with responsibility for the open item on the suppression pool liner. Michael Modes is from Region I and had the lead for the inspection, and we'll talk about that in the presentation today. And Matt Homiack is our mechanical engineer with responsibility for our operating experience program and the open item at Limerick.

We have attempted to streamline our program today, taking account for the background information that was already included in the applicant's presentation, so hopefully that will facilitate efficient review. We're going to focus on the areas that are unique to our review of the application and provide our characterization of the open items.

We are expecting written responses from the applicant on the open item so we are in the middle of the review. We are not in a position at this point in time because of that status of review to indicate a clear path forward on the open items. And you will get a sense of that from our presentation.

Before we get into our formal presentation I'd like to ask Bill Holston who is a senior mechanical engineer in the division to respond to Mr. Stetkar's question earlier about the internal inspection program of large-bore piping and consistency with the GALL. Bill?

MR. HOLSTON: Good afternoon. My response to that, or I understand the question to be how the applicant will be age-managing the internal surfaces of the surface water piping that is buried. And we worked with the applicant throughout the application and what they have committed to do is to take 10 locations every 2 years in aboveground service water piping and conduct ultrasonic examinations of that piping to detect any corrosion.

And that piping select -- the selection of those locations will be based upon similar flow rates as buried piping. And given that they have similar environments, internal environments between the service water piping that's buried and the aboveground service water piping, we believe that sufficiently examines the internals for both.

MEMBER STETKAR: Those are going to be you said volumetric examinations?

MR. HOLSTON: Yes sir, volumetric examinations.

MEMBER STETKAR: Okay. From the ID or the OD?

MR. HOLSTON: From the outside diameter.

MEMBER STETKAR: Okay. At least I know what they're going to do. And you feel that's consistent with the intent of GALL?

MR. HOLSTON: Yes, sir. The internal surfaces would be managed by -- you would manage them by AMP 11 M38 which is the internal inspection program which is an opportunistic program. So in this case rather than just simply going with opportunistic inspections the licensee committed to do, you know, guaranteed periodic inspections and 10 every 2 years will very fairly represent what we expect to see as age-managing in those internal surfaces of that piping.

MEMBER STETKAR: I guess I was looking at M41 under buried piping which seems to give you an indication that if you've had experience with leaks it says opportunistic examinations of non-leaking piping may be credited.

MR. HOLSTON: Well -- oh, I'm sorry.

MEMBER STETKAR: I don't know what you define as a leak. I mean, you know, they've had evidence of problems with their service water piping.

MR. BARTON: But that has to do with buried piping when you go down and actually look at it, right? And they're talking about a surface program.

MEMBER STETKAR: Well, this is for internals.

MR. BARTON: Right, right. Oh, okay.

MEMBER STETKAR: The internal examinations of buried piping.

MR. HOLSTON: M41 deals with external examination of piping only. There is no internal surface examinations in M41. The internal surface examinations for this piping would be under 11 M38.

MEMBER STETKAR: Section -- footnote 10 capital letter B. At least 25 percent of the code class safety-related or haz mat piping are both constructed from the material under construction is internally inspected by a method capable of precisely determining pipe wall thickness. That's in M41 under buried piping.

MR. HOLSTON: That's an alternative to if you do not want to do direct, you know, excavated direct visual examinations of the external surfaces you can substitute looking at 25 percent of the length with the volumetric method. That's the intent of AMP M41.

MEMBER STETKAR: Okay. I'll have to think about that because -- okay. I don't want to take up too much time because we have a lot of discussion on the suppression pools. Thank you.

MS. GALLOWAY: Thank you. Patrick?

MR. MILANO: Okay. Good morning, Dr. Shack and members of the subcommittee. I and the members of the NRR and Region I staffs are here to discuss the Limerick License Renewal Application as indicated here documented in the Safety Evaluation Report with open items that we issued in July of 2012.

In addition to the members up here at the table we also have staff who also participated in technical review and in the audits that were conducted at the plant that are here in case questions arise. Next slide, please.

This slide just predicts the general outline of the areas that were going to be covered in today's presentation and coincides with the -- specifically with the SER itself. Next slide.

I provided this slide only for

information. Everything on it was -- all the points that are being made on this slide were covered in the licensee's presentation. Next slide.

The staff conducted audits and inspections of the application during periods as shown on this slide. The purpose of the scoping and screening methodology audit was to review the applicant's administrative controls governing implementation of the scoping and screening methodology and the technical basis for selected scoping and screening results for various plant systems, structures and components, SSCs.

The audit also reviewed selected examples of component material and environmental combinations. Information contained in the applicant's corrective action database relevant to plant-specific age-related degradation. Quality practices applied during the development of the application and the training of personnel who participated in the -- also in the development of the application.

The purpose of this aging management program (AMP) audit was to examine Exelon's aging management programs and related documentation to verify that the applicant's claim of consistency with the corresponding AMPs in the Generic Aging Lessons

Learned (GALL) report were indeed correct.

As described in the GALL report the staff based its evaluation on the adequacy of each AMP on its review of 7 of the 10 AMP program elements. The other three program elements were audited during the scoping and screening methodology audit.

As Exelon indicated the staff reviewed 45 AMPs and documented the results in a report on February 28th of this year. If the applicant took credit for the program in the GALL report the staff verified that the plant program contained all the elements of the referenced GALL report program. In addition, the staff verified the conditions at the plant were bounded by the conditions -- excuse me, by the conditions for which the GALL report program was evaluated.

Of note, the applicant initially indicated that all of its programs were consistent with the GALL report. However, during the staff's AMP audit the staff found AMPs where the applicant was taking an exception and which should have been so stated in the application. In response to questions from the staff the applicant modified its description, thus resolving the noted gap.

And I'd like to present one example of a situation that I'm referring to here. The monitoring and trending program element in GALL report AMP II M24 recommends that daily readings of system dew point be recorded and trended. However, during its audit the staff found that the applicant's program basis document for the compressed air monitoring program states that the instrument air system dew point is continuously monitored and alarmed, inspected weekly and recorded quarterly. So it's just a, it was a matter of a difference in the way it was presented vice the way it was indicated actually in the field. And however we found this to be acceptable.

In addition, Region I conducted a regional inspection during the period from June 4th through the 21st of this year. Those inspection results will be presented shortly.

And lastly, the staff conducted an environmental review audit in support of the preparation of the Environmental Impact Statement which we are not going to be discussing anything environmental today.

MEMBER SKILLMAN: Pat, before you proceed onto slide 6.

MR. MILANO: Yes.

MEMBER SKILLMAN: Your first bullet, that scoping and screening methodology audit.

MR. MILANO: Yes.

MEMBER SKILLMAN: I think perhaps my question is more appropriately directed at Bob Kuntz. Four systems were chosen: essential service water, fuel pool cooling and cleanup, emergency diesel generator system and fuel transfer and air start subsystems. What is the basis for selecting only those four?

MR. MILANO: The basis for it is they were representative of it and also based on previous experience that the staff has with conducting other audits, especially in Region I wherein this is the last plant that is being inspected for license renewal, for initial license renewal. And it's just plant experience and these seem to be reasonable to -- reasonable samples in relationship to the total population. I don't know if, Rob, can you answer?

MEMBER SKILLMAN: Are these the same four that have been chosen at other plants in Region I that are applying for license extensions?

MS. GALLOWAY: We don't have the answer to that. Our scoping lead is on vacation this week so we can get back to you on that question, Mr. Skillman.

MEMBER SKILLMAN: My curiosity is why

these four. Why not six or seven? Or why two different from these? What is the basis for these four, please?

MS. GALLOWAY: Sure. We'll get back to you. Thank you.

MEMBER SKILLMAN: Thank you.

MR. MILANO: Slide 6, please. In addition to the audits and inspections that I've already mentioned the staff conducted in-depth technical reviews and issued 150 questions initially and about 200 questions overall as requests for additional information while preparing the overall Safety Evaluation Report. Slide 7.

Section 2 of the SER describes structures and components subject to aging management review. As you're well aware Section 54.21 of Part 54 requires the applicant to identify SSCs within the scope of license renewal and additionally to prepare an integrated plan assessment which identifies and lists those structures and components which are identified to be within the scope of license renewal that are subject to an aging management review.

Based on the staff's review of the applicant's detailed scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, review of quality controls applied to the development of the application and the training of personnel participating in that development, and the results of the scoping and screening methodology audit, and additional information from the RAIs the staff concluded that the applicant's scoping and screening program was consistent with the staff's Standard Review Plan for license renewal and the requirements of Part 54 of the regulations.

The staff then reviewed the summary of the identified safety-related SSCs which are those relied upon to remain functional during and following a design basis event as well as all non-safety related SSCs whose failure could prevent satisfactory accomplishment of any of the design basis functions.

Also, all SSCs relied on in safety analysis to perform a function that demonstrates compliance with the Commission's regulations for fire protection, environmental qualification, anticipated transit without scram (ATWS) and station blackout were identified. The staff found that the applicant's implementation in this area was consistent with both the SRP and applicable regulations.

If there are no other questions on this

slide I'll now turn over the presentation to Mr. Michael Modes, the Region I lead inspector who will discuss the license renewal inspection itself.

MR. MODES: Thank you gentlemen, it's always a pleasure to be here. As an overview this particular inspection took six inspectors over 3 weeks. You would probably note that's a pretty high level of inspectors spread out over a longer period of time. The only reason that occurred was we had a lot of exigent serious issues that the region was dealing with at the time at other plants and so Limerick staff and Exelon were very kind in allowing us to spread out the number of inspectors over a longer period. They kept support staff available to get the job done so that these inspectors could go on to these other facilities.

As usual we did the A2 inspection looking for those three-dimensional relationships. And we did 32 of 45 aging management programs were reviewed in total over that period of time. Next slide.

Because of the number of inspectors that went through over a longer period of time we did a lot of walkdowns even though it was beastly hot at the time. And this is just a partial list of the systems that were walked down. An extensive amount of walkdown and I took a pretty long tour of the facility in order to answer the material question -- pretty good.

MR. BARTON: Thank you, I didn't have to ask that this time.

MR. MODES: Yes, well, after 13 years --

MR. BARTON: You guys are getting ready, all right.

MR. MODES: Right, I give up. Thirteen years. Besides, this is the last time through, so.

(Laughter)

MR. MODES: Next slide. And what we concluded was that the scoping of non-safety SSCs and the application of the AMPs to those were acceptable. And the inspection results support a conclusion that reasonable assurance exists, that aging effects will be managed and intended functions maintained. Last slide.

Just wanted to note how long it has taken us in Region I to get through all of them. I've had the pleasure of inspecting every single one of these since June of `98. And it is the last slide, gentlemen, I will ever present to you.

(Laughter)

MEMBER SKILLMAN: So Michael, when you say material condition -- pretty good it's against that lens right there?

MR. MODES: Yes. Well, actually no. Prior to this endeavor I used to run the NDE mobile laboratory and I have had the pleasure of visiting 64 facilities. Prior to that I used to do NDE in general so it's a benchmark of probably the entire fleet.

MEMBER SKILLMAN: Thank you.

MR. MILANO: Okay, thanks Mike. Now moving onto Section 3 of the SER. Section 3 covers the staff's review of the applicant's aging management programs and the aging management review line items in each of the systems within scope and reviewed against the SRP and recommendations in the GALL report.

In its Table 2 of the application the applicant provided information concerning whether or not the AMRs, the aging management reviews, identified by the applicant aligned with the GALL report AMRs. For a given AMR in Table 2 the staff reviewed the intended function, the material, environment, aging management -- aging effect requiring management and the AMP combination for the particular system component type.

In the application the applicant also indicated where it was unable to identify an appropriate correlation in the GALL report. The staff also conducted a technical review of combinations not consistent with the GALL report.

For component groups evaluated in GALL for which the applicant claimed consistency and for which it does not recommend further evaluation the staff's review determined whether the plant-specific components were indeed bounded by the GALL report evaluation. If an AMR did not align with the GALL report the staff conducted a technical review to ensure adequacy and issued a request for additional information as necessary.

Based on its review of the application, the implementing procedures and a sampling of screening results the staff concluded that the applicant's screening methodology was indeed consistent with the Standard Review Plan guidance. Next slide.

As both Mike and I and others have indicated there were 45 aging management programs presented in the application. I do want to make one special note of the fact that there were no plant-specific aging management programs. Next slide.

MEMBER STETKAR: Before we get into the open item -- give me 2 minutes here. Diesel fuel oil storage tanks. And I may have just missed this so perhaps it's quick. There was an issue about their large diesel fuel oil storage tanks and the fact that they take samples from that tank 11 inches off the bottom. And you basically accepted that.

Are they going to do a volumetric examination of the bottom of that tank at any time? I see commitments to do volumetric examinations of little bay tanks here and there, but that's not the big storage tank. I'm concerned about 10 and a half inches of stuff laying on the bottom of that tank that nobody knows about.

MR. MILANO: There was some discussion in both the application and in the SER in that area. I think best if I turn it over to Mr. Gallagher and he can -- he and his staff.

MEMBER STETKAR: Okay. I didn't ask them in the sense of time but.

MR. GALLAGHER: Yes, we can answer that question. I'm going to have Mark Miller of our project team answer that question.

MR. MILLER: Mark Miller, Exelon license renewal. The main diesel oil fuel oil storage tanks are drained clean and inspected every 10 years. And should there be evidence of corrosion visually then we would be performing a UT.

MEMBER STETKAR: Okay, thank you. I missed that.

MEMBER SIEBER: Well, the other issue is sludge and water. Water settles to the bottom and that's why the line does not go all the way to the bottom, plus all the sludge lays there. And usually there are samples taken periodically at the level below the level of the section line to determine how much sludge and how much water is there. Is that periodically done?

MR. MILLER: Mark Miller, Exelon license renewal. The only sampling that we do on that tank is 11 inches off of the bottom of the tank. There's no physical connection. However, we do test for water by dropping down -- and I forget exactly what the term is, but it's material of some sort that detects the presence of water and that is dropped down to determine whether there is water sitting on the bottom.

MR. GALLAGHER: And I think Greg Sprissler of our chemistry department has something to add too.

MR. SPRISSLER: Greg Sprissler from the chemistry department. The tanks are pitched and at the bottom of the pitch is a low level sump.

Periodically the tanks are dewatered. So at that point there would be visual indication of any indication of sludge.

MEMBER STETKAR: There is a low point drain?

MR. SPRISSLER: Not a drain, a sump.

MEMBER STETKAR: Inside the tank itself?

MR. SPRISSLER: Yes. Operations periodically does checks for water content in the fuel and they pump out from the low-level sump.

MEMBER STETKAR: But -- so they can actually, someone can actually take a suction from that low point.

MR. SPRISSLER: They have a device that they use to do that.

MR. GALLAGHER: Basically suck the, you know, vacuum out that little volume.

MEMBER STETKAR: Okay. Well, why can't you then take credit for that for accumulation of, you know, corrosion sediment and everything else that might collect in that tank?

MR. GALLAGHER: I guess our periodicity wasn't in agreement with the GALL so we came up with what would be in agreement with the GALL and then this is extra that we do.

MEMBER STETKAR: Well, the GALL seems to say that you're supposed to take a sample from the lowest point in the tank if I read the GALL --

MR. GALLAGHER: Right.

MEMBER STETKAR: -- which this would do.

MR. HISER: This is Allen Hiser of the staff. This is one of the areas that I looked at during the audit and we verified through drawings that they do have an area where the sludge and things would collect.

MEMBER STETKAR: But they're not -- and you're okay with them not taking periodic samples from that area as a commitment?

MR. HISER: Yes. That was something that we found to be acceptable because they would be able to remove materials down there that, you know, water and things.

MEMBER STETKAR: I'm sorry but they're not committing to do that. They are not committing to do that. I would think it would be acceptable, for example, to take a suction, a sample from down there but they're not -- in particular they're not committing to do that.

MR. HISER: They -- I don't remember specifically whether there is a commitment but in terms of their draining, cleaning and inspecting the tank that was the main focus of the program.

MEMBER STETKAR: Okay. I don't -- Bill, I don't want to take up too much more time because we have a time constraint here.

MEMBER SIEBER: Well, I would like to ask you say that you take a sample out of the sump area periodically. What's periodically? What frequency?

MR. SPRISSLER: Once again Greg Sprissler from Limerick chemistry. I am actually not sure of the periodicity. My best estimate would be quarterly. That is an estimate.

MR. GALLAGHER: Yes, and I guess, you know, the reason we didn't -- that that wasn't the fulfilling our commitment consistent with the GALL is that that particular thing is fairly intrusive. You have to go down into the vault, remove the lid on the tank and that type of thing.

So the sampling we thought was sufficient to, you know, because we do the pre-loading of the fuel sampling, we do the frequent sampling. And we thought that that was more consistent with the GALL. And this other activity we do is a good practice that we have.

MEMBER SIEBER: Thank you.

MR. MILANO: Go on now to slide 14. The NRC characterized the issues regarding this, the open item that's presented on this page into three parts as noted on the slide. Because the applicant has covered the specific technical information on the slide I'm not going to repeat this.

Also, the applicant proposed this AMP to manage the aging of the suppression pool liner and downcomers for a loss of material from corrosion and to preserve the leak tightness barrier.

The applicant in part stated that the AMP addresses the inspection of primary containment components exposed to an uncontrolled indoor air and treated water environments. In addition, the program basis document states that the Section 11 IWE program is an existing AMP that will be enhanced to manage the suppression pool liner and coating system as you heard from the licensee previously. Next slide, please.

As just stated the applicant proposed an enhancement of its existing IWE program to manage the aging effects in the suppression pool liner and coating system. In an enhancement to the detection of aging effects program element the applicant stated that prior to the period of extended operation the AMP will include more frequent inspections and selected and phased re-coating of the corroded areas of the suppression pool.

The applicant has described the specific attributes in this enhancement as noted on this slide. I provide them now, however, just as a reference in case we need to go back to them. Next slide, please.

In the SER the overall open item was, like I said, it was expressed in three parts. The staff will only address the first two parts as indicated in this slide because the third part dealing with the downcomer corrosion appears to be on a path to resolution.

Regarding the remaining two parts the staff seeks additional information from the applicant about the corrosion mechanisms affecting the suppression pool liner and the criteria and supporting basis in the program for coating degradation. As you heard earlier the applicant has been managing the degradation of the liner rather than maintaining the coating system.

The staff is aware that the Limerick suppression pool liners have been subjected to both general and pitting corrosion or localized corrosion as the applicant indicated. The staff has come to this conclusion from the results of inspections discussed in the applicant's assessment report of the liner degradation. Thus the staff lacks sufficient information from the applicant to conclude that pitting corrosion is not a degradation in the liner.

Because of the operating history of pitting corrosion in the Limerick liners the enhanced AMP should fully account for pitting corrosion. This is important because operating experience has shown that pitting corrosion rates are higher, usually 2 to 10 times higher than general corrosion rates, are not as predictable and could result in a leak in the liner over time.

The staff is also concerned that the applicant's methods and technique for measuring the amount of liner material lost to corrosion may not be an effective means to determine the remaining thickness of the liner. The applicant uses depth gauges to measure loss of material due to general and pitting corrosion.

This may not be appropriate in all areas experiencing general corrosion some of which has exhibited up to 35 mils of general corrosion adjacent to the pits. It's unclear to the staff how the reference datum of the original thickness of the liner will be considered in monitoring the total material loss in the inspected areas.

Moving onto the --

MEMBER SKILLMAN: Before you change slides, this is a pure curiosity question. Is there any correlation between the operability of the cathodic protection system on this plant, both units, and the pitting and degradation of the liner? Has anyone pulled that thread?

MR. SHEIKH: I'm not aware of this issue.

MEMBER SKILLMAN: Does anybody know what the operating history is of the cathodic protection system for Limerick?

MR. SHEIKH: Bill Holston might.

MR. HOLSTON: My name's Bill Holston, staff with the Division of License Renewal. They have an operational cathodic protection system. It protects the buried piping but I am not aware that it protects the surfaces you're discussing there.

MEMBER SKILLMAN: I'd be curious whether that's a design consideration. In my consulting independent from this I've been on plants where the cathodic protection system was not functional, was hooked up backwards, was connected to some components and not others, was not grounded properly and it turned out the cathodic protection system was part of the problem rather than part of the resolution of the problem. So I'm just wondering if when you ask questions about not knowing why the rates are what they are if perhaps there is another mechanism that's fairly simply discovered that hasn't been touched upon yet.

MR. SHEIKH: I can only add to this that this kind of pitting has been observed at other BWR plants, suppression pools. And the pitting is in the same kind of ranges. We are aware, at least I am aware of Cooper Plant and Duane Arnold Plant where the pitting was in that kind of range.

MS. GALLOWAY: Abdul, when you speak could you be closer to the microphone so we can all hear you? Thank you.

MR. SHEIKH: I repeat that the pitting which has been observed here in Limerick is similar to other plants which, you know, like Cooper and Duane Arnold where they were pitting in the suppression pool of similar magnitude.

MEMBER SKILLMAN: I understand your answer. I would like to put on the record the question and ask for a response is there a correlation between operability of cathodic protection and what you're seeing on the corrosion of the liner.

MR. HISER: Are you speaking specifically of the buried pipe cathodic protection program? Or are you speaking of any stray occurrence that could?

MEMBER SKILLMAN: Well, generally the cathodic protection system covers more than just the buried pipe. It's condenser, buried piping, however the plant is grounded. And unless it's connected properly you can have portions of the plant that have electrical potentials that are driving degradation. So that is the general basis of my question, is there a correlation here. Thank you.

MR. MILANO: We'll take that down and we'll provide an answer back to you.

MEMBER SKILLMAN: Thank you.

MR. MILANO: Okay, continuing on with this slide onto the second part. On coating degradation the staff notes that the application has three criteria as you've heard before the results of which will be used to initiate implementation of the coating maintenance plan. The staff is unclear as to the technical basis for using the 25 percent loss of coated area as a criterion in the enhancement.

Second, it's unclear to the staff how the liner plates that have experienced a coating loss to date some of which is exceeding 25 percent and up to

72 percent of a specific plate surface area will be prioritized and corrected in a phased approach as the applicant has indicated prior to the start of the period of extended operation.

This cold mean that areas with up to 24 percent of the coated area degraded could possibly not be re-coated even at the start of the period of extended operation in 2024 for Unit 1.

You know, today we heard some additional information for the first time being presented in this area to help clarify what Exelon meant by its phased approach. And the staff will be looking forward to Exelon's submission of its response to the open items as they indicated next week.

I would state of note that the applicant has classified the suppression pool liner coating as service level 1 because of the potential for coating failure to adversely affect the post-accident fluid systems.

And also the suppression pools were initially filled in the nineteen eighties and in the nineteen nineties the applicant determined that the coating was beyond its projected service life. And as Mr. Barton indicated my recollection is reading that the projected service life was determined to be 12 years.

The staff also wishes to note that in its SER it indicated that recent industry operating experience as described in the NRC's Information Notice 2011-15 titled "Steel Containment Degradation and Associated License Renewal Aging Management Issues."

This information notice provides information of the type of situations such as showing that zinc coatings have a limited lifetime and may not be effective during the period of extended operation if not reapplied.

MEMBER POWERS: When they make these lifetime projections what's changing? What's being lost from the coating that means it won't perform its function?

MR. MILANO: Well, it is a sacrificial coating and that's what the -- that's in terms of setting up its, you know, the galvanic relationships and stuff the zinc is expected to oxidize first and sacrifice itself to save the base metal. I don't know if Mr. Hiser wants to say anything more?

MR. HISER: No, that's exactly right.

MEMBER POWERS: So you would -- when they make the projection they're saying okay, we've depleted all the zinc here, it's all been turned into zinc oxide or zinc carbonate.

MR. HISER: I would assume that's the kind of calculation. I don't think we've reviewed the calcs and I wouldn't want to speak to what the vendor has done.

MEMBER POWERS: So if somebody comes in and says well, yes, my zinc's still here he's okay then?

MR. HISER: Well, I think the qualified life like that depend on certain conditions, and if the conditions in the field are different, maybe less severe, then presumably the lifetime could be extended.

MEMBER POWERS: Yes, I mean if I'm marketing the zinc I'm going to say okay, what's the most severe thing they're going to have here and that's how I'm going to do my calculations. In reality it's something more mild like that's the guy who comes in and says well, you know, my zinc is still here. I mean, that's pretty easy to check. If it was the hydroxyl bonding to the steel and de-adhesion that's a much harder thing to check.

MR. HISER: Yes, I think in this case the discussion that we've had of the qualified life is really not to say anything bad about what the plant condition is but just the fact that for a 40-year initial lifetime there's no surprise that the coating is no longer intact in many places because it really wasn't designed to be there still.

MEMBER POWERS: Well, I think what I'm driving at is that when we have these limited lifetime components there's some projection of how long it's going to last. Here's one where even if that projection is a very accurate one it is, as you accurately pointed out, based on some estimate of what conditions, what the service conditions are. Those are not the real service conditions. So the fact that its lifetime, projected lifetime has been exceeded doesn't mean anything if it's still functional. Because we know what makes it non-functional.

MR. HISER: And in the case of the coating like this it makes evident.

MEMBER POWERS: Yes, I mean --

MR. HISER: It's evident whether it's there --

MEMBER POWERS: It's fairly evident.

MR. HISER: -- and functional or not.

MEMBER POWERS: And it's not catastrophic. I mean, if your coating goes away for a cycle can you corrode all the way through the liner? I don't think so.

MR. HISER: I don't think so either but I think that's one of the concerns that we have, comparing the general corrosion with the -- whether you want to call it pitting corrosion or corrosion that results in pits in the liner I think the concern we have is there's some very deep pits. And whether that behavior could be replicated in other portions of the liner is really the concern that we have on the re-coating side effects.

MR. MILANO: Okay. Barring any further questions I'll go to the next slide which is the second open item that the staff has.

MEMBER BROWN: Can you back up?

MR. MILANO: Yes.

MEMBER BROWN: Just something I didn't understand from what they said during the re-coating, applying the re-coating. The zinc is part of the coating, right?

MR. MILANO: The original coating.

MEMBER BROWN: The original coating.

MR. MILANO: Yes.

MEMBER BROWN: When they said they re-coated they re-coated with an epoxy. Has that also got new zinc? I mean, is that zinc compound or whatever it is?

MR. MILANO: No.

MEMBER BROWN: So there is no renewal then of whatever zinc was lost in that coating area.

MR. HISER: No, it's a different approach, it's a barrier approach as opposed to --

MEMBER BROWN: A sacrificial approach. Okay, thank you.

MR. HISER: But then that coating as well will have a certain qualified life to it.

MEMBER BROWN: I understand. I didn't hear anything on that, on the new re-coating. When they go back and re-inspect subsequently in other outages or whatever they do on their spot inspections do you re-inspect the epoxy-coated parts different than you do --

MR. HISER: Well, my understanding is --

MEMBER BROWN: -- different criteria or what do they do?

MR. BARTON: You look for blisters and stuff in the epoxy.

MR. HISER: If they have a service level 1 coating that would be something that they would maintain. So they would have an inspection program I believe as a part of their IWE program.

MEMBER BROWN: Sort of slow -- I'm an electrical guy so you've gone way over my head.

MR. HISER: But the coating --

MEMBER BROWN: What does that mean, a service level 1? You mean it's supposed to last forever or?

MR. HISER: No, it has certain requirements associated with it in terms of inspection.

MEMBER BROWN: But I'm looking for the difference between the epoxy re-inspections. If you've mapped those is there something different you do when you re-inspect periodically relative to those areas you've already re-coated relative to the ones you do for zinc? Is there some different process?

MR. BARTON: You'd look for different things with an epoxy coating than you would for the zinc.

MR. HISER: The epoxy coating would have its own specific criteria from acceptance by inspection. So areas that have been re-coated would require certain inspections, techniques, frequency, acceptance criteria, et cetera. They would be different from the zinc coating because they have different functions and therefore different requirements.

MEMBER BROWN: I understand they're different. Okay.

MR. MILANO: Well indeed, in the application itself they have, the applicant did indicate that any areas where they observed flaws and they've re-coated either for that or because the re-coating was done because they've exceeded, you know, let's say one of those 25 percent area issues and they've re-coated the whole plate that they have committed to do a follow-on inspection during the next refueling outage of that plate surface area.

MEMBER BROWN: So areas that were re-coated with the epoxy have a -- okay. So roughly 2 years later then you're saying that they would re-look at that during their next outage.

MR. MILANO: That's correct.

MEMBER BROWN: And they've committed to that.

MR. MILANO: Yes, they have.

MR. HISER: I don't know that it's 2 years. I mean again --

MEMBER BROWN: Well, they said refueling outage. I thought they said 2 years during the break.

MR. GALLAGHER: Just as a clarification. So, we inspect three times every 10 years. And so that's done, that's the interval. And so when you do the inspection you inspect the entire submerged area. So whether there's zinc coating or epoxy coating it's all included in the inspection.

And three times per 10 years is just, that's an ISI interval -- excuse me, period. The interval is 10 years. A period is three of them in an interval and that's how that's determined.

MEMBER BROWN: But those don't necessarily correspond to outages.

MR. GALLAGHER: Correct. So sometimes you do it like, you know, if you can imagine there's three periods in a 10-year. So, it could be like two outages, one outage, two outage, you know. That's kind of how you would do it.

MR. MILANO: Yes, Mr. Gallagher is correct. It was the next refueling outage wherein there was going to be an inspection.

MEMBER BROWN: Okay. All right. Thank you.

MR. MILANO: With that I'll go onto the second open item. This open item describes the staff's concern related to the consideration of operating experience during the term of the renewed license. This issue has been discussed with the ACRS in previous meetings.

In March of this year the staff issued final license renewal interim staff guidance ISG 2011-5 entitled "Ongoing Review of Operating Experience." This guidance emphasizes that operating experience is a key feedback mechanism used to ensure the continued effectiveness of the aging management programs and activities.

In response to the staff's RAIs the applicant has described the process that will be used to review operating experience and the staff has reviewed the description of these processes against the framework set forth in the ISG.

And I'll repeat this even though Exelon has described the issue itself well and as indicated today they -- it appears they're on a path towards resolution.

The staff's position is that any enhancements to the existing operating experience review activities that are necessary for license renewal should be put in place no later than the date when the renewed operating licenses are issued.

The applicant identified a number of

enhancements in its existing operating experience program. However, these enhancements will not be implemented until about 2 years after issuance of the renewed license.

The issue that the staff has as Exelon has indicated that they're responding to is -- it relates to that period between the issuance of the renewed license and that date, the 2-year following date wherein they were going to implement this enhancement.

And, well this issue is open pending receipt of the applicant's additional information and the staff's review of it. Next slide.

As you know, time-limited aging analyses are those licensing calculation analyses that in part consider aging effects, involve time-limited assumptions defined by the current operating term, are relevant in making a safety determination and involve conclusions or the basis for conclusions related to the capability of SSCs to perform their intended functions.

For each evaluation, analyses or calculation the applicant has to determine that: one, the analyses remain valid for the period of extended operation; two, that the analyses have been projected to the end of the period of extended operation; or three, the effects of aging or the intended functions will be adequately managed during the period of extended operation.

The staff evaluated the applicant's basis for identifying those plant-specific or generic analyses that need to be identified as TLAAs. The applicant two exemptions based on a TLAA but neither of these exemptions is required for the period of extended operation.

The exemptions were associated with the pressure temperature, the PT limits developed using exemptions from Appendix G of Part 50 to permit use of ASME code cases and 588 and 640.

Since the current PT limits are only valid for 32 effective full power years the exemptions must be superceded before the period of extended operation. Therefore, the current exemptions will not be required during the period of extended operation.

Based on its review and the information provided by the applicant the staff concludes that the applicant has provided a list of plant-specific exemptions granted in effect that are based on TLAAs and the applicant has provided an evaluation that justifies the continuation of any exemptions for the period of extended operation. Thus in summary the staff has no open issues in the area of TLAAs section for the SER.

And lastly, just in conclusion, and you've seen this conclusion before, the staff's conclusion will be provided in the final SER on the basis of its review. And pending the satisfactory review and resolution of the open items the staff will be able to determine that the requirements of 10 C.F.R. 54.29(a) have been met for the renewal of the Limerick Generating Station operating license. And subject to any further questions this concludes the staff's presentation.

MEMBER SKILLMAN: Back to slide 17, please, second bullet. A cynical interpretation of that bullet would be you give us the renewed operating license and then we'll do some more work. Is that what that bullet means?

MR. MILANO: The second bullet, you're talking about we'll the enhancements within 2 years following receipt of the renewed licenses. In reality, in reality these enhancements, you know, are generally put into place only at the time that the renewed operating license has been granted and stuff. In this case here you're indeed correct as they --

MS. GALLOWAY: Perhaps Matt Homiack can

answer the question.

MR. MILANO: Okay.

MR. HOMIACK: Pat, I can field this.

MR. MILANO: Thank you.

MR. HOMIACK: Essentially the enhancements the applicant has described are consistent with the framework set forth in the staff's interim staff guidance document. However, the only inconsistency is in the implementation schedule, the ISG. And the staff's position is that they had -- to be put in place when the renewed licenses are issued. In this case the applicant has indicated that it would like to put them in place 2 years after issuance of the renewed licenses. And I believe that's mainly based on them, the applicant implementing them across its fleet.

MEMBER SKILLMAN: Okay, thank you.

MR. MILANO: Any other questions? Thank you.

CHAIRMAN SHACK: I'm going to open it up for comments. Are there any comments from anybody in the audience? Do you want to check and see if their line is open and if there are any comments from anybody who's been listening in?

I'd like to thank the staff for their

presentation. As I understand it we have no real schedule to bring this to the full committee because again we're still working on the resolution of the open items. So that's indefinite at the moment unless you have some?

MR. MILANO: At this point here the staff does have a projected schedule for the safety review portion as compared to the environmental review. And based on the two open items and the fact that from what we've heard today and what we knew coming into here we believe that the staff should be able to issue a final SER in January of 2013.

And with that there's a -- currently have a full committee presentation scheduled for February of next year. Again, it's subject to being able to complete the open items but it looks right now like that should be, that could be met.

CHAIRMAN SHACK: Okay. Is there anybody on the line that would like to make a comment? No. Hearing none we'll assume there are none. I'd like to thank you.

Again, any final questions from the committee? Anybody have any observations they'd like to make?

MR. BARTON: I think it was a quality

presentation and I think we heard a good presentation from both the applicant and the NRC. I struggled to find issues in this application when I was doing the review. So I think it was a good quality application.

MEMBER SKILLMAN: I would echo that. I think this has been a very high-quality presentation with a lot of very good material.

I would make two observations. As complex as scheduling would be to do a complete coating of the suppression pool wall and floor it's my thought is that it may be beneficial for the long run to do the entire suppression pool at one time so it is treated uniformly and thoroughly as opposed to breaking that if you will repair up into a number of outages where each prior application is in the throes of its own degradation different from the next application. It seems to me that that raises variability in understanding what the health of that liner coating would be. That would be my one comment. Thank you.

CHAIRMAN SHACK: Any other comments? If there are no further comments we'll adjourn. Thank you.

(Whereupon, the foregoing matter went off the record at 11:32 a.m.)

Limerick Generating Station License Renewal Application

ACRS Subcommittee Presentation
September 05, 2012

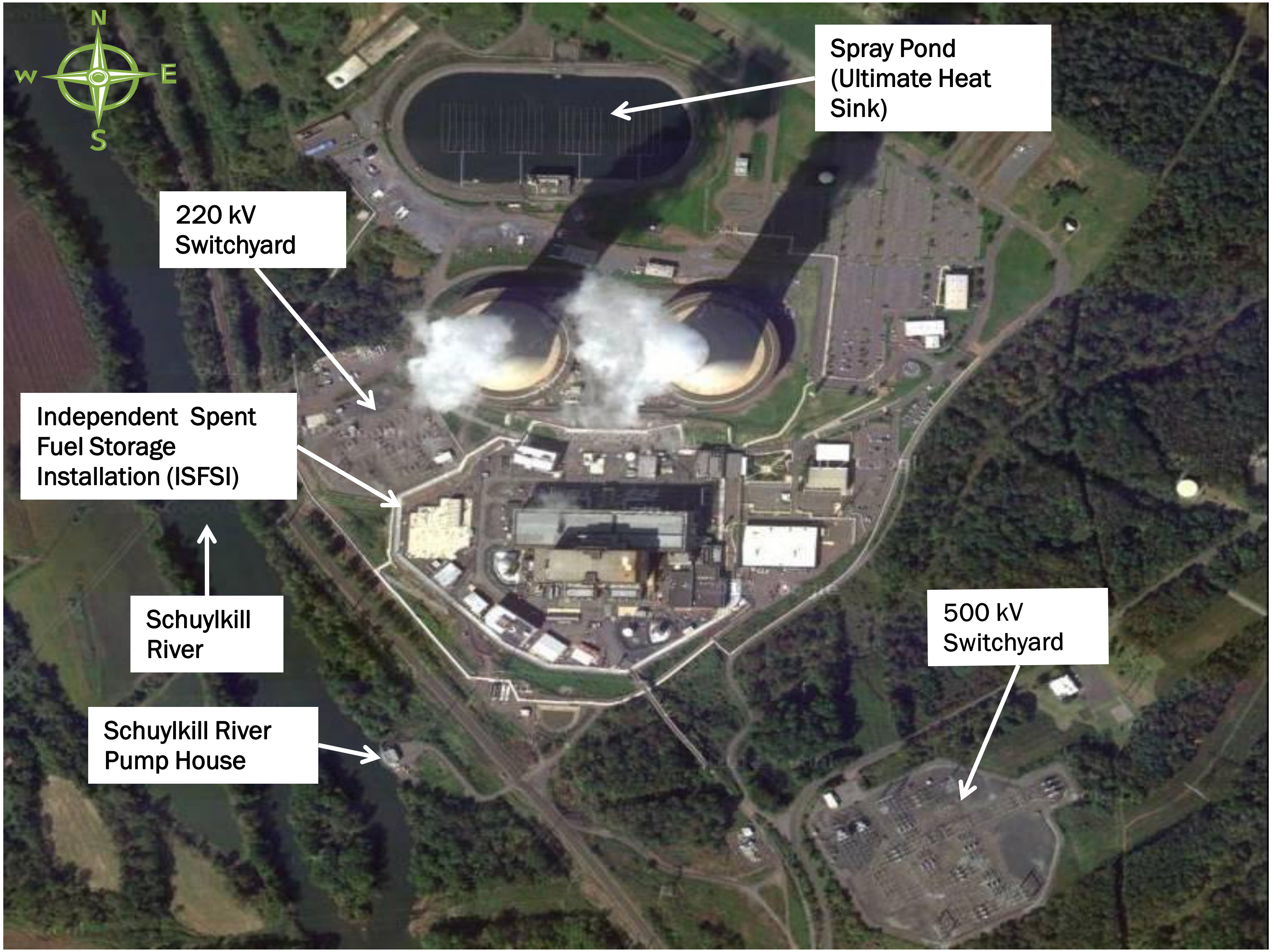
Introductions

• Mike Gallagher	VP, Exelon License Renewal
• Gene Kelly	License Renewal Manager
• Dan Doran	Limerick Engineering Director
• Mark DiRado	Limerick Engineering Programs Manager
• Barry Gordon	MSc, PE, Senior Consultant, SIA, Inc.

Agenda

• Introductions	Mike Gallagher
• Site Description	Dan Doran
• Limerick Overview	Dan Doran
• GALL Consistency & Commitments	Gene Kelly
• SER Open Items	Gene Kelly
– Suppression Pool Liner	Mark DiRado / Barry Gordon
– Operating Experience	Gene Kelly
• Questions and Close	Mike Gallagher

Limerick Generating Station



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Limerick Overview

	Unit 1	Unit 2
Initially Licensed to 3293 MWt	10/26/84	6/22/89
5% Power Uprate to 3458 MWt	1/24/96	2/16/95
Turbine Rotor Replacements	1998	1999
Digital Feedwater Control	2004	2005
Independent Spent Fuel Storage Installation (ISFSI)	2007	2007
1.65% Measurement Uncertainty Recapture (MUR) 3515 MWth	4/8/11	4/8/11
Main Transformer replacements	2014	2011
Recirculation Pump Adjustable Speed Drive Units (ASD)	2012	2013
Next scheduled Refueling Outage	March 2014	March 2013
Current License Expiration	10/26/24	6/22/29

GALL Revision 2 Consistency
and
License Renewal Commitments

GALL Consistency and Commitments

- Submittal based on GALL Revision 2

- Aging Management Programs – 45
  - Consistent with GALL – 44
  - Exception to GALL – 1

- License Renewal Commitments
  - UFSAR Supplement (Appendix A of the LRA)
  - Managed by Exelon Commitment Tracking program based on Nuclear Energy Institute 99-04, "Guidelines for Managing NRC Commitment Changes“
  - Total of 47 Commitments
    - 45 associated with aging management programs
    - Operating Experience program enhancement
    - Unit 1 Recirculation Nozzle flaw re-evaluation

SER with Open Items

SER With Open Items

Open Item 3.0.3.2.13-1 ASME Section XI, Subsection IWE Suppression Pool

- The Staff needs additional information regarding aging management of suppression pool liners and downcomers in the following areas:
  - Prioritized approach to implementation of coating plan
  - Methods for examination of coating underwater
  - Expected corrosion mechanism
  - Downcomer acceptance criteria

Open Item 3.0.5-1 Operating Experience for Aging Management Programs

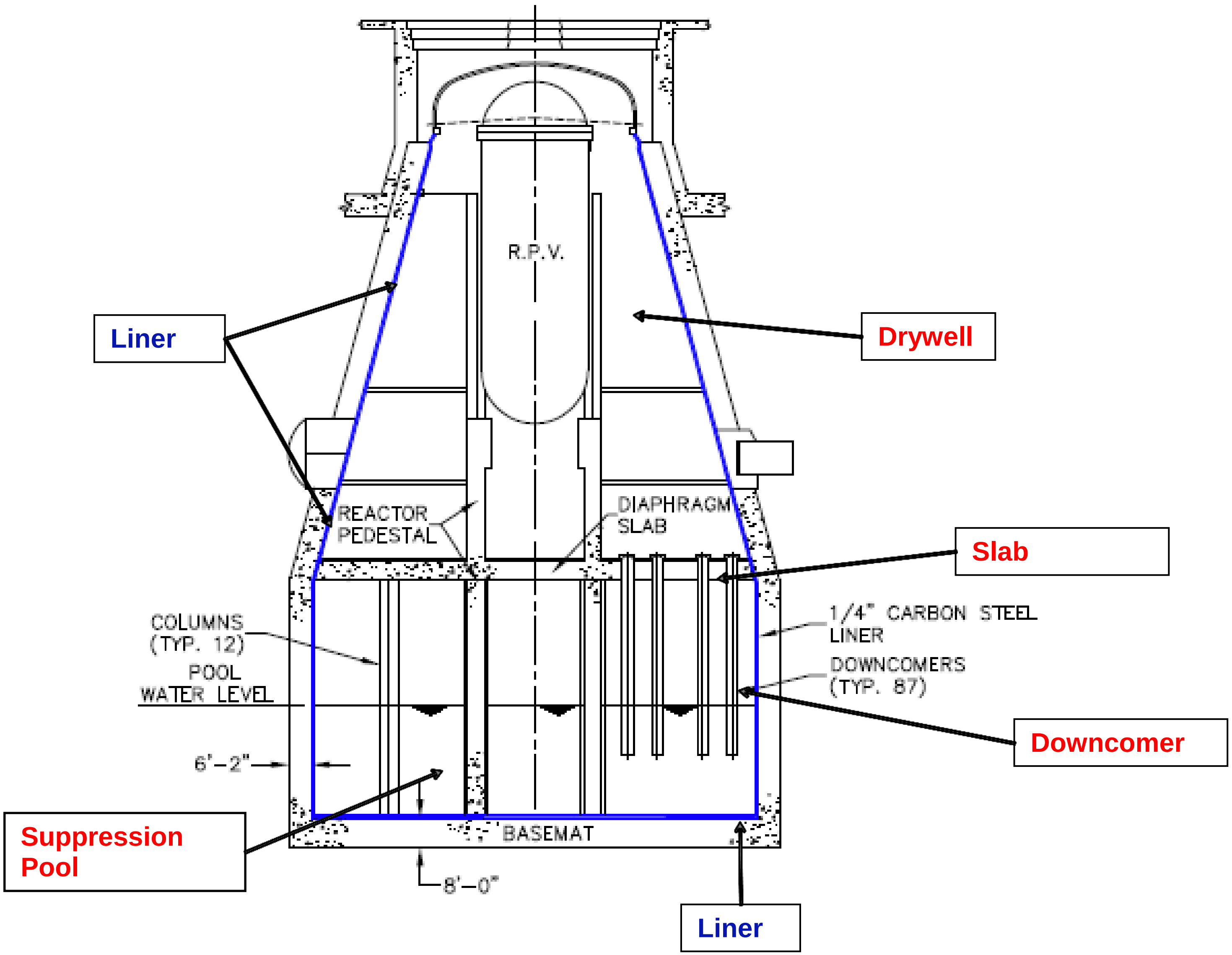
- The staff needs additional information to determine whether operating experience will be considered in the period between issuance of the renewed licenses and implementation of the program enhancements
- Exelon will provide the information to the staff to address this issue

Suppression Pool

Key Points

- Robust MARK II reinforced containment design
- 100% liner thickness margin
- Environment minimizes corrosion
  - Inerted atmosphere
  - Excellent water chemistry
  - Low corrosion rate
- Material condition well understood
- Enhancements to Aging Management Program initiated in 2012 well before PEO in 2024
- Suppression pool liner intended function will be maintained through PEO

MARK II Containment



MARK II Containment - Suppression Pool

- 250-mil continuous carbon steel liner
- 6'-2" (minimum) reinforced concrete wall
- Liner serves as a leakage barrier
- Liner structural integrity limits
  - 125 mils minimum general area thickness
  - 62.5 mils minimum local area thickness

Suppression Pool Coating System

- Service Level I inorganic zinc sacrificial coating
- 6-8 mils initial dry film thickness
- License renewal intended function is to "maintain adhesion" so as to not impact ECCS suction strainers
- Coating is a design feature to assist in asset protection
- Service life sustained by Coating Maintenance Plan
  - Frequent full ASME exams
  - Spot recoat and proactive large area recoat
  - Regular cleaning and sludge removal

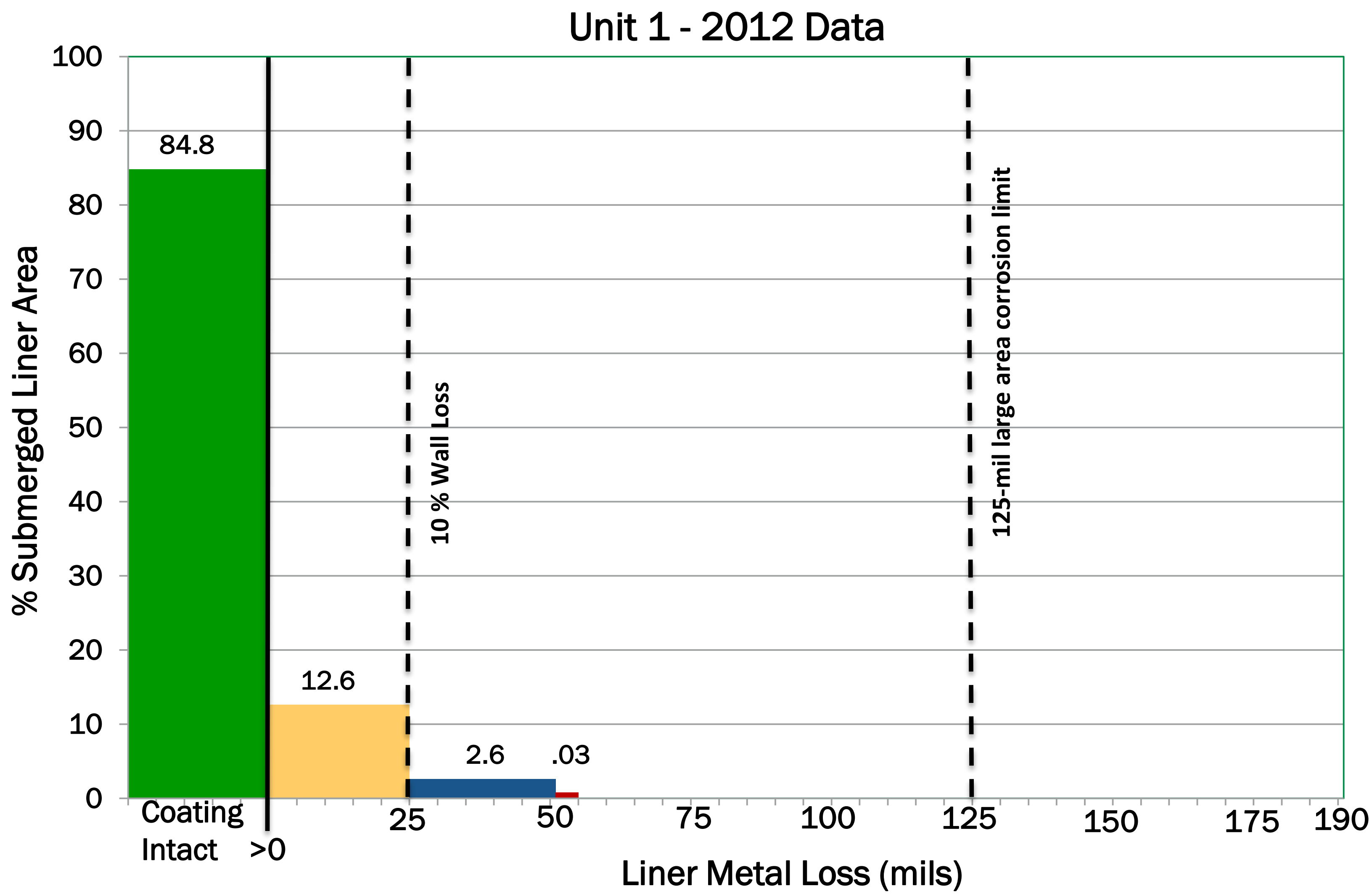
Suppression Pool Water Environment

- Suppression pool water quality meets BWRVIP-190, “BWR Water Chemistry Guidelines”, EPRI Report 1016579
  - Nearly neutral pH (range of 6.4 to 6.8)
  - Temperatures at which low corrosion rates are expected
  - Chlorides average ≤ 2 ppb (recommended ≤ 200 ppb)
  - Sulfates average ≤13 ppb (recommended ≤ 200 ppb)
- Primary Containment inerted with nitrogen
- General corrosion rate predicted < 2 mils per year
- Corrosion data from evaluation grids confirms rate

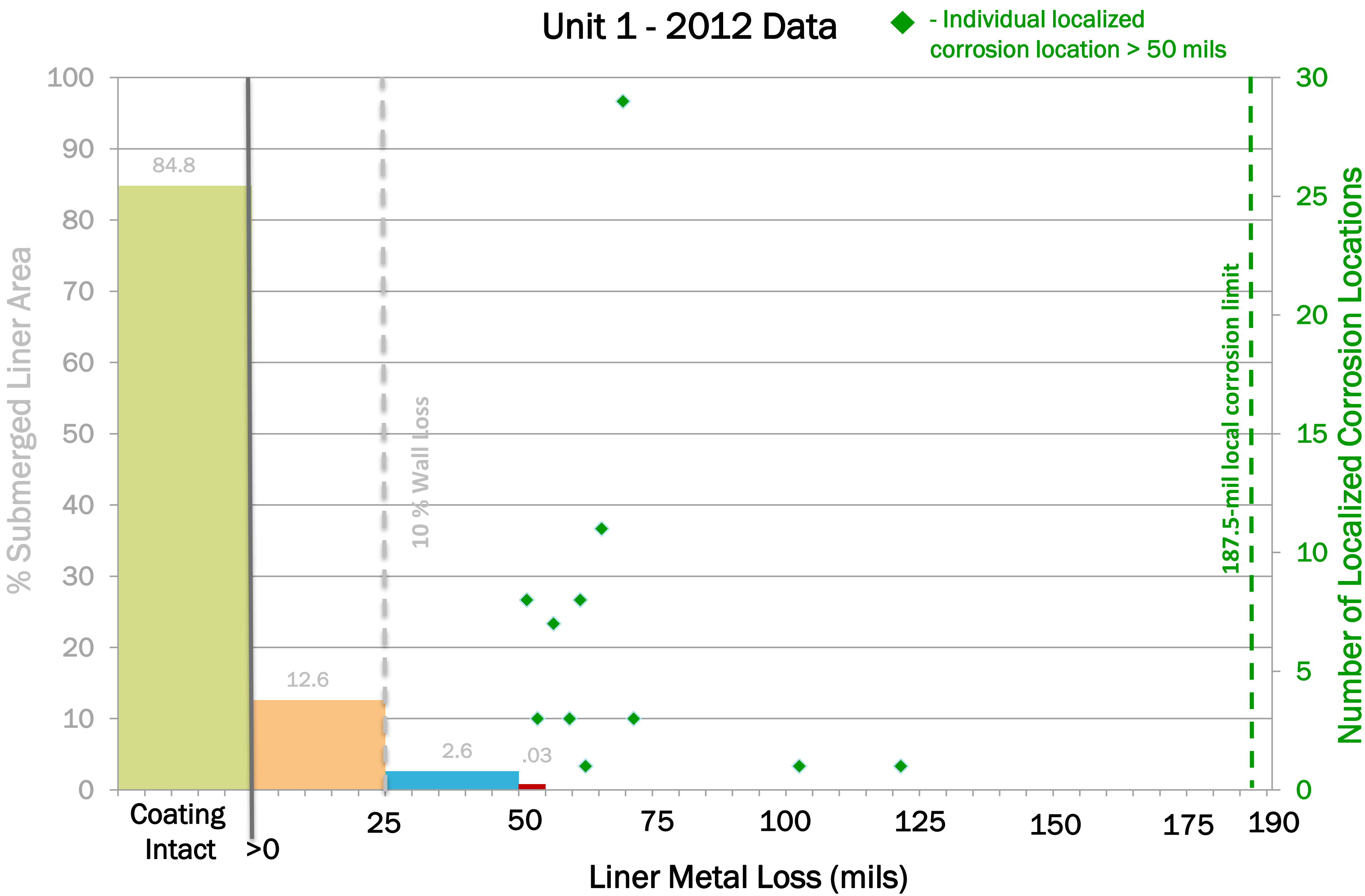
Corrosion Environment

- General corrosion is the predominant mechanism in the Limerick suppression pools
- Pitting corrosion is not expected in suppression pools
  - Carbon steel does not form passive films in the low temperature suppression pool water
  - Aggressive anionic species such as chlorides are absent (< 2 ppb) in the suppression pools
  - The suppression pool environment has limited amounts of dissolved oxygen since the airspace above the water is inerted with nitrogen during normal operation

Unit 1 Liner Condition



Unit 1 Liner Condition



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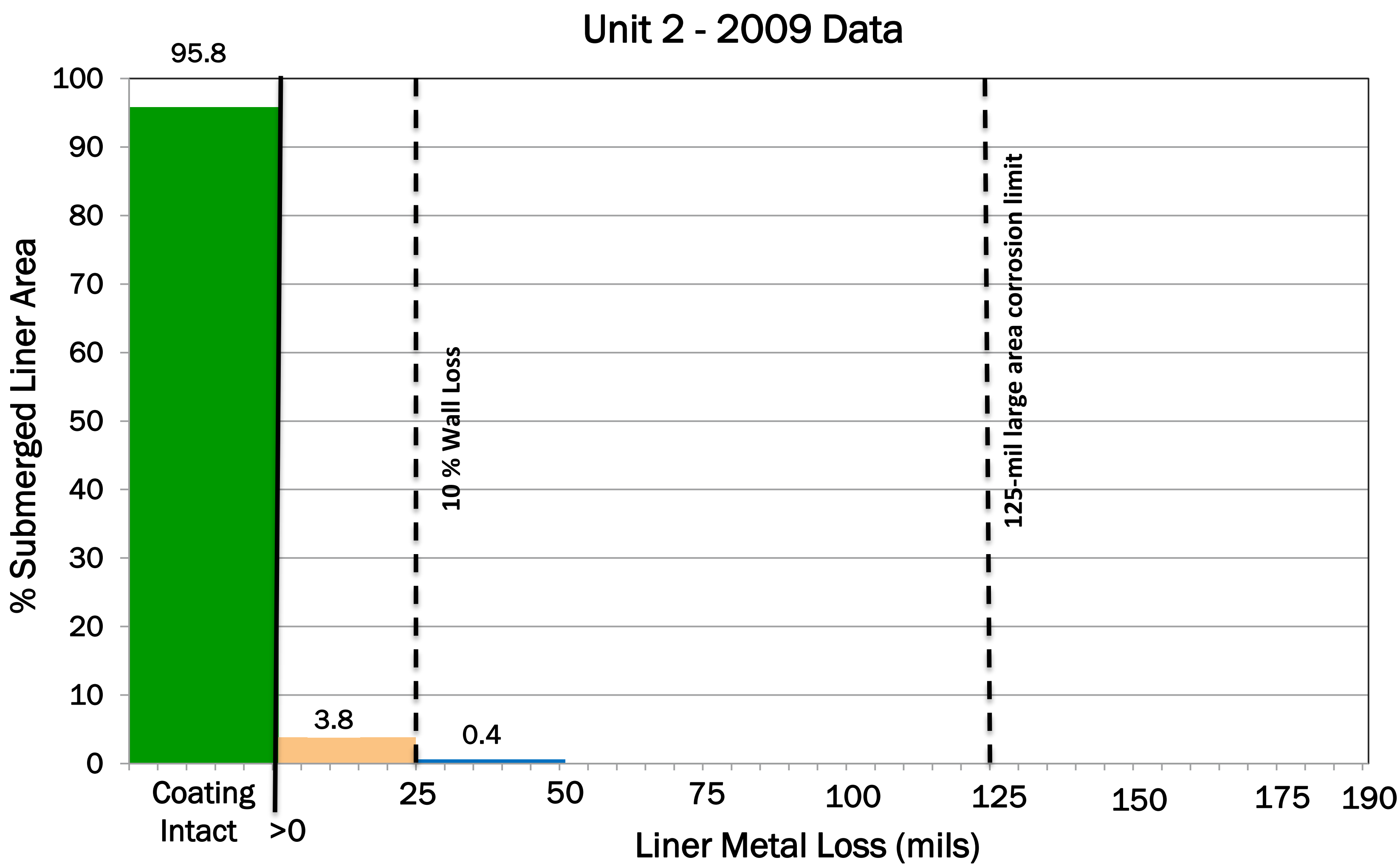
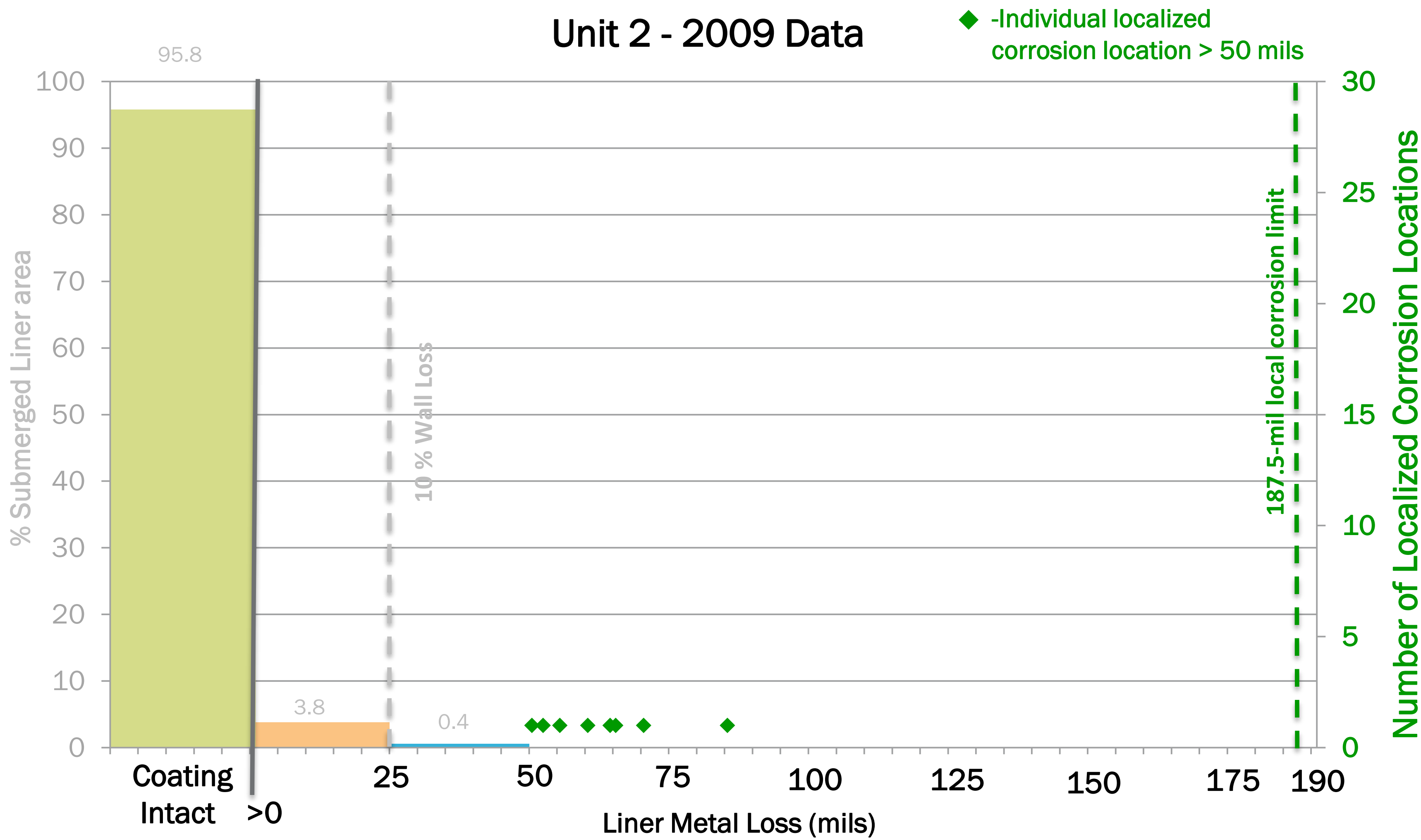
Unit 2 Liner Condition



Unit 2 Liner Condition



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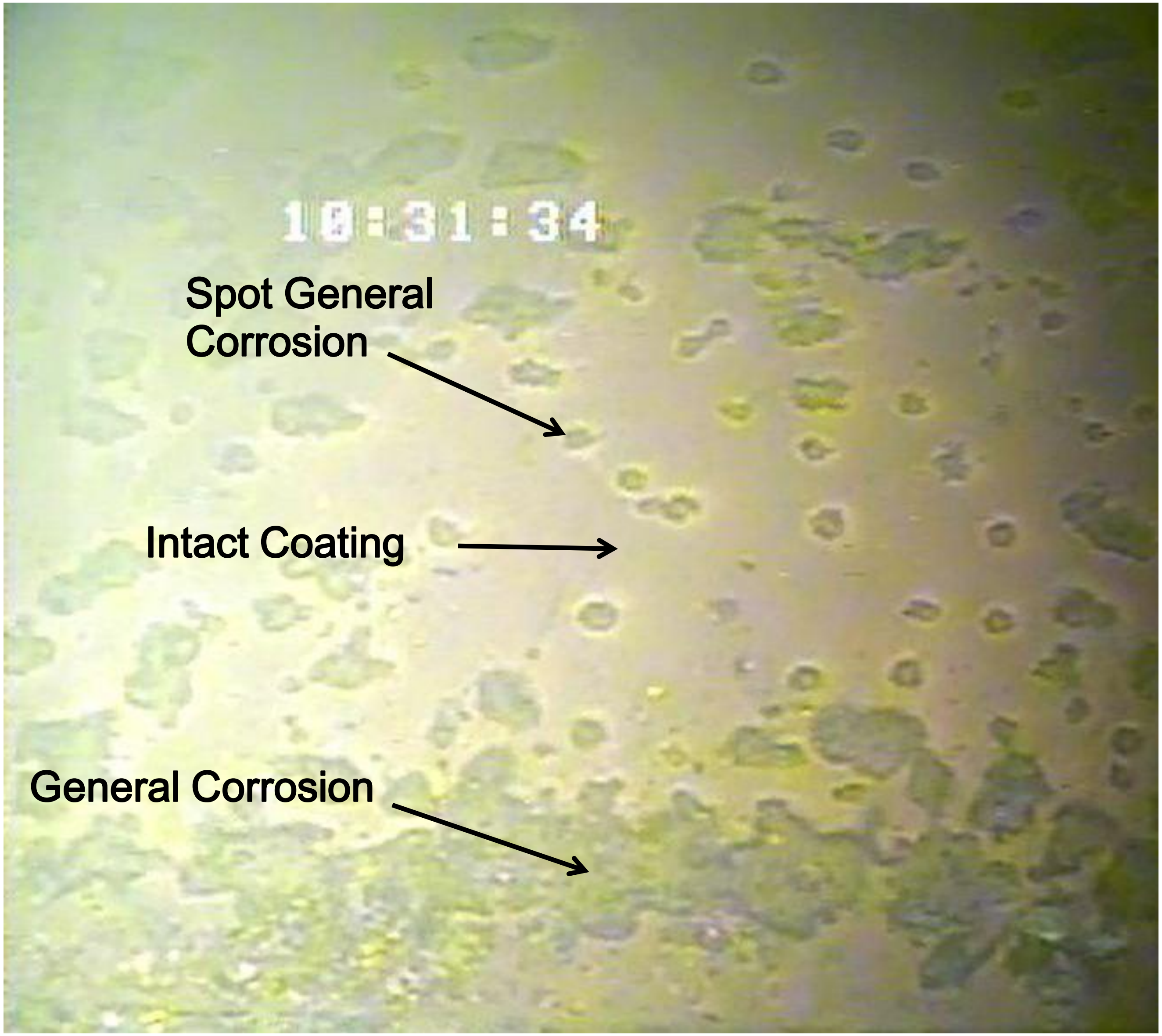
Downcomers

- 24-inch diameter, 375 mils wall thickness
- Interior coated with epoxy; exterior with inorganic zinc
- 45 feet long, lower 11 feet submerged
- Four downcomers (with vacuum breakers) capped at bottom
- Unit 1 downcomers inspected in 2012 (< 25 mils wall loss)
- Unit 2 downcomers inspected in 2009 (< 10 mils wall loss)
- Metal loss acceptance criteria established:
  - 44 mils general area metal loss/ 331 mils thickness limit
  - 62.5 mils local area metal loss/ 312.5 mils thickness limit
  - Criteria will be incorporated into inspection procedure

Methods of Examination Underwater

- Qualified personnel
  - ANSI N45.2.6 and ASTM D4537 for coating
  - ASNT CP-189 and ASME XI for liner
- 100% VT-3 visual exam performed
- Areas characterized using ASTM D610 (SSPC-VIS-2), "Standard Test Method for Evaluating Degree of Rusting on Painted Steel Surfaces"
- VT-1 examination of augmented areas
  - 25 mils general area or 50 mils local area thickness loss
  - Dial-depth gage for metal loss
  - Dry film thickness gage for coating
- Visual exams supplemented by volumetric (UT) examination in accordance with IWE-3200

Suppression Pool Plate



- Examination from 2010 refueling outage
- Visible area approximately 1 ft^2

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Aging Management Program Enhancements

	Enhancement	Basis
1	De-sludge each Refueling Outage (2 yrs)	Frequent cleaning minimizes corrosion sites.
2	Full ASME IWE examination each ISI period (3 times in 10-year ISI interval) for 100% of the submerged surface	100% inspection will occur frequently to confirm expected low corrosion rate for this environment and provide opportunities for recoating.
3	Area recoat for general corrosion > 25 mils	General corrosion is 2 mils per year. Acceptance limit is 125 mils metal loss. Recoating at 25 mils (10% wall loss) and frequent inspection interval ensures minimal additional wall loss.
4	Spot recoat local corrosion > 50 mils	Pitting corrosion is not expected due to environment. If localized metal loss rate were hypothetically 16 mils per year, then a 50-mil spot would progress to 114 mils depth over 4 years. The acceptance limit for local corrosion is 187.5 mils metal loss.
5	Recoat plates with > 25% loss of coating	Proactively recoat large general areas before significant corrosion occurs.
6	Initiate enhancements in 2012 for Unit 1 and 2013 for Unit 2	Allows 7 cycles for Unit 1 and 9 cycles for Unit 2 prior to the PEO to recoat.

Prioritized Approach to Implementation

Prior to PEO

- Local corrosion > 50 mils recoated in outage of discovery
- Areas with general corrosion > 25 mils recoated based on ranking of affected surface area (high to low) prior to PEO
- Plates with > 25% coating surface depletion recoated based on ranking of area depleted and thickness loss prior to PEO

During PEO

- Local corrosion > 50 mils recoated in outage of discovery
- Areas with general corrosion > 25 mils will be recoated in outage of discovery
- Plates with > 25% coating surface depletion will be recoated no later than the next scheduled inspection

Open Item 3.0.3.2.13 -1 Resolution

- Prioritized approach to implementation of coating plan
- Methods for examination of coating underwater
- Expected corrosion mechanism
- Downcomer acceptance criteria

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Summary and Conclusions

- Robust MARK II containment design
- 100% liner thickness margin
- Environment minimizes corrosion
  - Inerted atmosphere
  - Excellent water chemistry
  - Low corrosion rate
- Material condition well understood
- Enhancements to Aging Management Program
  - Initiated in 2012 well before PEO in 2024
  - Suppression pool liner intended function will be maintained through PEO

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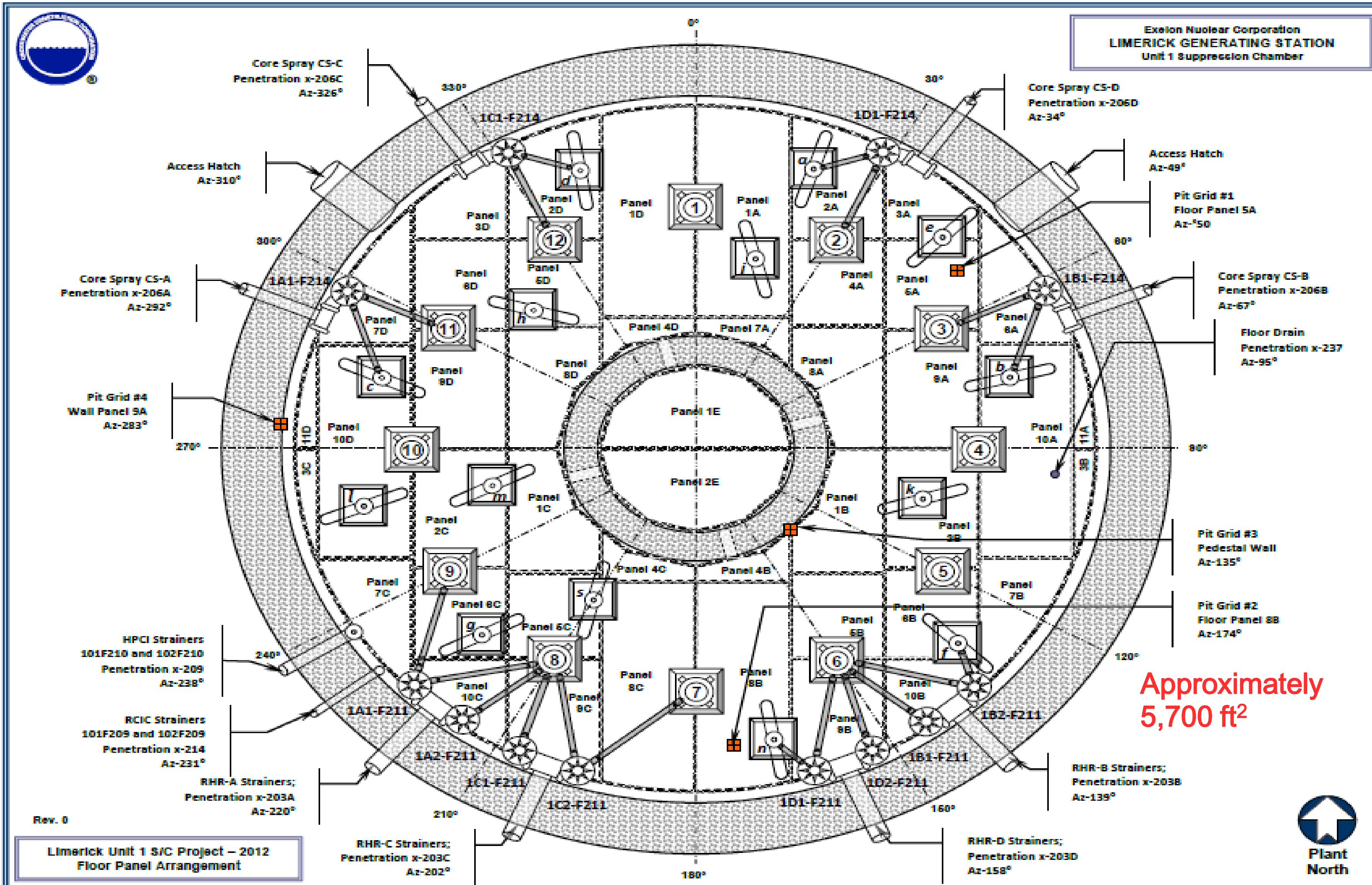
Closing Comments

Questions?

Back-up Slides

Back-up Slides

Suppression Pool Floor Plan



Approximately 5,700 ft^2

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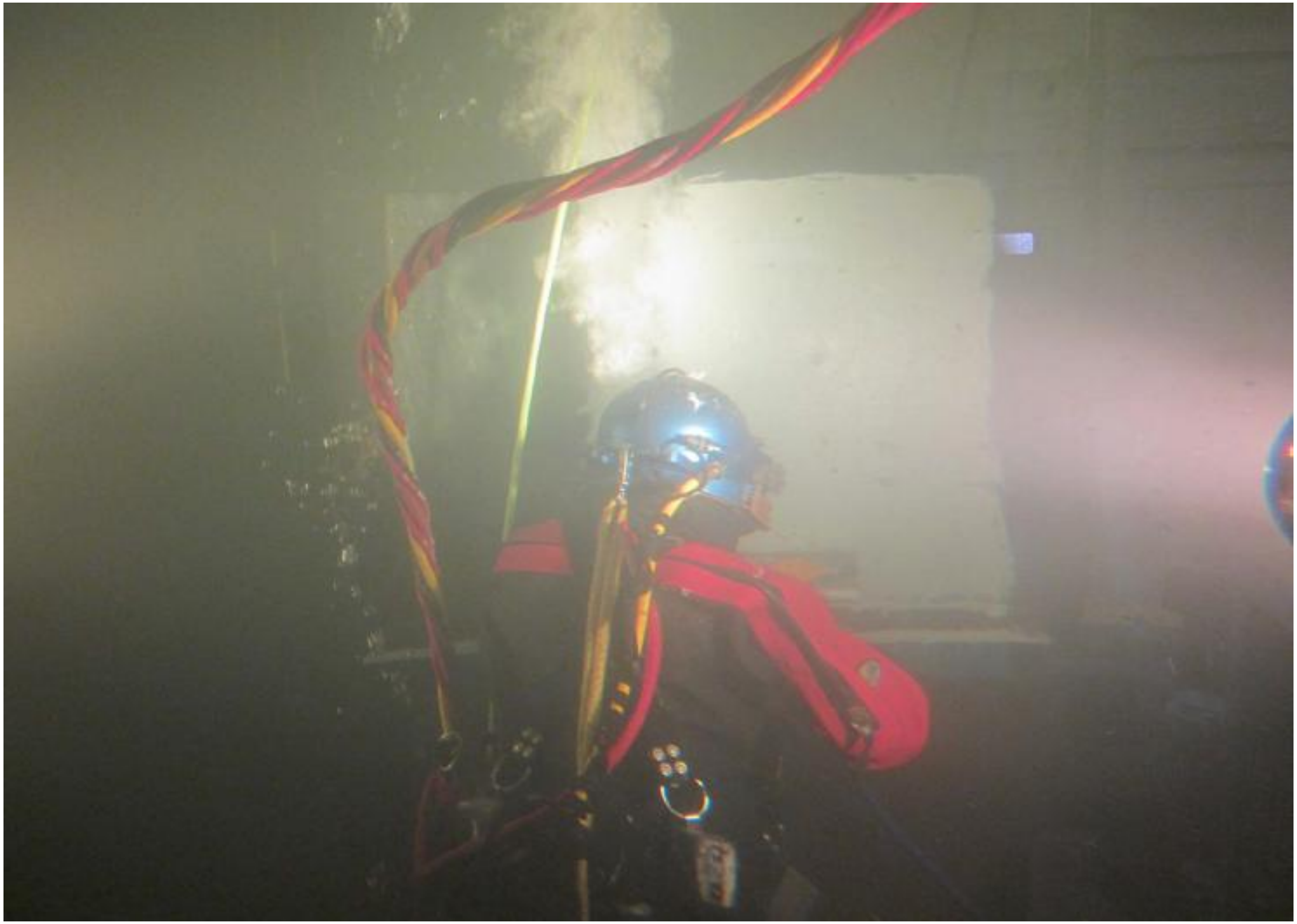
Mockup – Wall Panel



Mockup – Floor Panel

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U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Advisory Committee on Reactor Safeguards
License Renewal Subcommittee

Safety Evaluation Report (SER) with Open Items
Limerick Generating Station, Units 1 and 2

Issued: July 31, 2012

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Safety Evaluation Report (SER) with Open Items

Limerick Generating Station, Units 1 and 2

September 5, 2012

Patrick Milano, Sr. Project Manager
Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of Limerick license renewal review
- SER Section 2, Scoping and Screening review
- Region I License Renewal Onsite Inspection
- SER Section 3, Aging Management Programs and Aging Management Review Results
- SER Section 4, Time-Limited Aging Analyses

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Facility Facts

- **License Renewal Application (LRA) submitted June 22, 2011**
  - Applicant: Exelon Generation Company, LLC (Exelon)
  - Facility Operating License Nos. NPF-39 and NPF-85
  - Docket Nos. 50-352 and 50-353
  - Current License Expiration Dates: October 26, 2024, and June 22, 2029
  - Requested renewal period of 20 years beyond the current license dates
- **Approximately 21 miles northwest of Philadelphia, PA**
- **BWRs (GE 4) with Mark II containment design**

Audits and Inspections

- Scoping and Screening Methodology Audit
  – September 19-23, 2011(report December 9, 2011)
- Aging Management Program (AMP) Audit
  – October 3-14, 2011 (report February 28, 2012)
- Region I Inspection (Scoping and Screening & AMPs)
  – June 4-21, 2012 (report July 30, 2012)
- Environmental Review Audit
  – November 7-10, 2011

Overview (SER)

- Safety Evaluation Report (SER) with Open Items issued July 31, 2012
- SER contains 2 Open Items (OIs):
  - Suppression Pool Liner and Downcomer Corrosion
  - Operating Experience
- Final SER is tentatively expected to be completed in January 2013

SER Section 2 Summary

Structures and Components Subject to Aging Management Review

- <u>Section 2.1, Scoping and Screening Methodology</u>

- <u>Section 2.2, Plant-Level Scoping Results</u>

- <u>Sections 2.3, 2.4, 2.5 Scoping and Screening Results</u>

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Regional Inspections

Overview

- Six inspectors over three weeks
- 10 CFR 54.4(a)(2) inspection
- 32 of 45 Aging Management Programs Reviewed

Regional Inspections

Walk-downs

- Systems in the Units 1 and 2 Reactor Enclosures
- Systems in the Units 1 and 2 Turbine Enclosures
- Essential Service Water pipe tunnel
- 2A Emergency Diesel Generator Room
- Battery Rooms
- Refueling Floor
- Control Room
- Unit 1 and 2 Spray Pond Structure
- Compressed Air System
- Turbine Building, Containment Building, Diesel Generator Building, and Intake Structures
- Metal Enclosed Buses

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Regional Inspections

Inspection Conclusions

- Scoping of non-safety SSCs and application of the AMPs to those SSCs were acceptable.
- Inspection results support a conclusion that reasonable assurance exists that aging effects will be managed and intended functions maintained

Regional Inspections

All Region I Plants Inspected for Renewal

• Calvert Cliffs	June 1998
• Peach Bottom	May 2002
• Ginna	June 2003
• Millstone	July 2004
• Nine Mile	February 2005
• Oyster Creek	March 2006
• Pilgrim	September 2006
• Vermont Yankee	February 2007
• Fitzpatrick	April 2007
• Indian Point	January 2008
• Beaver Valley	June 2008
• Susquehanna	August 2008
• Three Mile Island	December 2008
• Salem Hope Creek	June 2010
• Seabrook	April 2011
• Limerick	June 2012

Section 3: Aging Management Review

- Section 3.0 – Use of the GALL Report
- Section 3.1 – Reactor Vessel & Internals
- Section 3.2 – Engineered Safety Features
- Section 3.3 – Auxiliary Systems
- Section 3.4 – Steam and Power Conversion System
- Section 3.5 – Containments, Structures and Component Supports
- Section 3.6 – Electrical and Instrumentation and Controls System

SER Section 3

- 3.0.3 – Aging Management Programs
  - 45 Aging Management Programs (AMPs) presented by applicant and evaluated in the SER
  - No plant-specific AMPs

SER Section 3 Open Items

- **Open Item 3.0.3.2.13-1 ASME Section XI, Subsection IWE**
- Corrosion in suppression pool carbon steel liner
  - General corrosion of liner up to 35 mils in depth, and affecting up to 72% of surface area in some liner panels
  - Pitting up to 122 mils deep
  - Method for augmented inspection to measure loss of liner material
- Degradation of liner coating
  - Existing coating is inorganic zinc material, 6-8 mils thick
  - Adequacy of criteria for selecting locations for recoating
  - Effective identification of degradation in liner plates underwater
- Identification of acceptance criterion for downcomer corrosion

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Open Item 3.0.3.2.13-1

Proposed Enhancement to IWE AMP

Concerning Suppression Pool Liner Plate Degradation

- Remove any accumulated sludge in suppression pool every refueling outage
- Examine submerged portion of suppression pool every ISI period
- Use results of examination to implement coating maintenance plan
  - Perform local recoating of areas with general corrosion that exhibit greater than 25 mils loss in plate thickness
  - Perform spot recoating of pitting greater than 50 mils deep
  - Recoat plates with greater than 25 percent coating depletion
- Coating Maintenance Plan will be implemented for the selected areas in a phased approach starting in 2012

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Open Item 3.0.3.2.13-1

Concerns Expressed by the Staff

- Corrosion of liner
  - Account for pitting corrosion in the enhanced AMP
  - Justify technique to measure remaining thickness of liner plates
- Coating Degradation
  - Justify basis for using 25% loss of coated area to classify affected area requiring augmented inspection
  - Define and justify phased approach of selective recoating to manage aging due to corrosion and pitting

Open Item 3.0.5-1

SER Section 3.0.5 — Operating Experience for Aging Management Programs (OI 3.0.5-1)

- Applicant identified several areas where enhancements to operating experience review activities are necessary
- Applicant plans to implement these enhancements within two years of receipt of the renewed operating licenses
- Given this schedule, it is not clear whether operating experience related to aging management and age-related degradation will be adequately considered in the period between issuance of the renewed licenses and implementation of the enhancements

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SER Section 4: TLAA

- 4.1 Identification of TLAAs
- 4.2 Reactor Vessel Neutron Embrittlement
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Containment Liner Plate and Penetration Fatigue Analyses
- 4.6 Other Plant-Specific TLAAs

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Conclusion

On the basis of its review and pending satisfactory resolution of the open items, the staff will be able to determine that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Limerick Generating Station

Wen, Peter

From: aceactivists@comcast.net
Sent: Monday, September 03, 2012 9:07 AM
To: Wen, Peter
Subject: Comments for 9-5-12 Subcommittee Meeting

September 3, 2012

Peter Wen
Designated Federal Official
ACRS Contact For ACRS Subcommittee Meeting

Re: Limerick Nuclear Plant License Renewal

Dear Mr. Wen,

The Alliance For A Clean Environment (ACE) just learned about this meeting. ACE is a grassroots group extremely concerned about the safety of millions of people surrounding Limerick Nuclear Plant. NRC failed to notify us about this open to the public meeting, even though we received all the letters NRC sent to Exelon. It is not possible for us to attend, but we would like this committee to consider our comments.

First, we applaud important questions and concerns raised by NRC staff on serious issues concerning corrosion and thinning, in letters to Exelon. We urge this committee to avoid accepting Exelon's illogical explanations and excuses, as has been done in the past. The nuclear industry has admitted some impacted equipment is too big and expensive to replace, putting communities like ours at high risk. We remind NRC there have already been problems at Limerick and the current license isn't up until 2029. The lives of many people depend on NRC standing firm against relicensing on these vital issues.

While we will wait until EIS public hearing comments to address most of the corrosion issues we find alarming, there is one that we feel compelled to bring to your attention at this time. Since 2006, we have been very concerned with and asked questions about corrosion from the cooling tower air emissions. We received MSDS sheets from Exelon on the products they use as additives in the cooling towers and discovered most are extremely corrosive. These do not disappear. They end up in the air or discharges into the river.

NRC also expressed concern about corrosive impacts from Limerick's cooling towers, specifically chlorine, as sodium hypochlorite. NRC pointed to impacts at other nuclear plants.

Are you aware?

- **Limerick uses massive amounts of Chlorine (Sodium Hypochlorite) - 16,000 to 58,000 LBS. USED EVERY DAY**
  (From Exelon's NPDES Permit Application)
- **This doesn't disappear. It ends up in the air and water.**

Exelon told NRC that the chlorine plume from Limerick's cooling towers is of little concern for corrosion of Limerick equipment because it blows offsite. Clearly, not all blows off-site as suggested by Exelon, according to problems NRC cited elsewhere. However, while evidence shows equipment has been corroded elsewhere, we are also worried about the harmful health impacts to our residents from what Exelon admits is blowing off-site.

- **When it can corrode steel, what is the chlorine doing to residents around Limerick who breathe in the chlorine from Limerick's drift?**
- **The World Health Organization has a strict limit on chlorine in air due to its harmful health impacts. Lung cancer and other lung problems are ramped in communities near Limerick, a fact acknowledged by respiratory therapists and physicians. Many residents around Limerick reported corroded cars and lawn furniture.**
- **Since 2006, ACE repeated requested year-long air monitoring for all the corrosive chemicals added to Limerick's cooling towers. No agency has complied with our request.**

The astronomical use of chlorine and other harmful corrosives clearly jeopardizes vital equipment and public health. This is an important reason to reject Limerick Nuclear Plant relicensing.

Massive amounts of corrosive chemicals used at Limerick Nuclear Plant also jeopardize all the miles of underground pipes. Many corrosive chemicals are used. One example:

Are You Aware?

- **Sulfuric Acid - 40,000 to 60,000 LBS. used at Limerick EVERY DAY**
- **This doesn't disappear. What vital equipment is being damaged?**

Another issue that must be considered by NRC:

Are You Aware?

- **Limerick Nuclear Plant cannot meet Clean Water Act standards for its massive dangerous discharges into the Schuylkill River, a vital drinking water source for almost 2 million people.**

- Limerick Nuclear Plant's Total Dissolved Solids (TDS) discharges in over 14 BILLION GALLONS PER YEAR, include corrosive cooling tower chemicals and the broad range of radionuclides from Limerick's operations.
- Both Exelon and PA DEP admitted that Limerick cannot meet Safe Drinking Water standards (500 mg/L) for TDS under the Clean Water Act, or even DRBC's far higher standards (1,000 mg/L).

Instead of requiring reverse osmosis to filter Limerick's TDS (including cooling tower toxics and radionuclides),

- **PA DEP has planned to issue Limerick's 5-Year NPDES permit, without limits and with an exemption of this pollution. Exemptions don't remove threats to water and health.**

PLEASE RESPOND:

How Can NRC Justify Allowing Limerick to be Relicensed, When Limerick Can't Meet Clean Water Laws for Discharges That Include Radionuclides, Into A Vital Drinking Water Source For Almost Two Million People?

- Circumventing the law does not remove the threats to water and public health.

- Exelon can reduce the risk with filtration of Outfall 001. To issue relicensing without requiring reverse osmosis for these dangerous discharges would be both irresponsible and negligent.
- NRC has never done testing (much less a year of continuous independent monitoring) for all radionuclides discharged from Limerick's most dangerous discharge pipe, Outfall 001.
- Evidence at Limerick and elsewhere shows why monitoring, calculating, testing, and reporting controlled by Exelon can't be trusted.

Please consider our comments and respond so that we can report your response to our community.

Thank you,

Dr. Lewis Cuthbert
ACE President