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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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PLANT LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY

DECEMBER 3, 2014

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ROCKVILLE, MARYLAND

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

COMMITTEE MEMBERS:

GORDON R. SKILLMAN, Subcommittee Chairman

RONALD G. BALLINGER, Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

PETER C. RICCARDELLA, Member

JOHN W. STETKAR, Member

ACRS CONSULTANT:

JOHN J. BARTON

DESIGNATED FEDERAL OFFICIAL:

KENT L. HOWARD, SR.

ALSO PRESENT:

JIM ANNETT, Exelon

JOHN BASHOR, Exelon

GARY BECKNELL, Exelon

ED BLONDIN, Exelon

STEVE BLOOM, NRR

DONALD BRINDLE, Exelon

EDWARD J. CARLY, Next Era Energy

PAUL CERVENICA, Exelon

DYLAN CIMOCK, Exelon

SAMUEL CUADRADO, NRR

HIAN DA, Exelon

JOHN DAILY, NFF

GEORGE DEMETRI, Exelon/Westinghouse

YOIRA DIAZ-SANABRIA, NRR

CLIFF DOUTT, NRR

DAN ENRIGHT, Exelon

W. JACK FEIMSTER, Exelon

NESTOR J. FELIZ-ADORNO, III

DON FERRARO, Exelon

BARF FU, NRR

MIKE GALLAGHER, Exelon

LYNNE GOODMAN, DTE Energy

KIM GREEN, NRR

ETHAN HAUSER, DTE Energy

JOHN HILDITCH, Exelon

ALLEN HISER, NRR

MELVIN HOLMBERG, RIII

WILLIAM C. HOLSTON, NRR

CHRIS HOVANEC, NRR

JOHN HUFNAGEL, Exelon

KENDRA HULLUM-LAWSON, DTE Energy

CRAIG INGOLD, Exelon

TIM JOHNSON, Exelon

ROGER KALIKIAN, NRR

CHARLES KELLER, Exelon

CHRISTINE KINKEAD, Exelon

RALPH KOHN, Exelon

RAY KUYLER, Morgan Lewis

JUAN A. LOPEZ, NRR

MICHAEL MARSHALL, NRR

JOHN MATTHEWS, Exelon

JAMES MEDOFF, NRR

DANEIRA MELENDEZ-COLON, NRR

NEAL MILLEN, Exelon

CHRIS MILLER, NRR

SONNY MIN, NRR

JEFFREY MITCHELL, NRR

DENNIS MOREY, NRR

CASEY MUGGLESTON, Exelon

ALBERT PIHA, Exelon

PHIL O'DONNELL, Exelon

ALOYSIUS O. OBODOAKO, NRR*

DOUGLAS P. OVERBECK, Exelon

ANDREW PRINARIS, NRR

TOM QUINTENZ, Exelon

PHILLIP J. RAUSH, Exelon

LINDSAY ROBINSON, NRR

PETE SHIER, Exelon

ANN MARIE STONE, RIII

PETER TAMBURRO, Exelon

GEORGE THOMAS, NRR

PAUL WEYHMULLER, Exelon

MARK YOO, NRR

MOHAMMED YOUSUF, Exelon

*Present via telephone

T A B L E O F C O N T E N T S

P R O C E E D I N G S

(8:31 a.m.)

CHAIRMAN SKILLMAN: Ladies and gentlemen, good morning. This meeting will come to order. I=m Gordon Skillman. I=m the Chairman of the Plant License Renewal Subcommittee. The Subcommittee will review the combined license renewal application for the Byron Station Unit 1 and 2 and Braidwood Station Units 1 and 2 Nuclear Plants.

ACRS members in attendance are Pete Riccardella, Harold Ray, Dana Powers, John Stetkar, ACRS Chairman, John Barton, our consultant, and Ron Ballinger. Our Federal Official is Kent Howard.

I would like to make an opening comment. This is an unprecedented review for the ACRS. This is a review of four units at two different sites. While the units are very similar, they are not identical. So there are some issues of commonality and some issues of difference that we hope to hear about today.

I want to say up front we recognize the immense effort that Exelon has invested in this application. And the investment that you=ve made to bring your team here today, we thank you for that. And we look forward to a very constructive meeting.

This morning we will hear presentations from the Division of License Renewal, from Region III and the Exelon Generation Company regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the 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 not received written comments or requests for time to make oral statements from members of the public regarding today=s meeting.

The entire meeting will be open to public attendance. There will be a phone bridge line. To preclude interruption of the meeting, the phone will be placed in a listen-in mode during the presentations and the Committee discussion.

A transcript of this meeting is being kept and will be made available as stated in the Federal Register Notice. Therefore, I request that participants in this meeting please use the microphones located throughout the meeting room when addressing the Subcommittee. The participants are requested to please identify themselves first and then speak with sufficient clarity and volume so that they can be readily heard. I also ask that you please silence all of your electronic devices.

We will now proceed with the meeting. And I call upon Chris Miller to begin the presentation. Chris.

STAFF INTRODUCTION

MR. MILLER: Thank you, Chairman Skillman. We=re looking forward to the presentations today. And staff looks forward to the interaction.

As stated, I=m Chris Miller, Director of the Division of License Renewal. I have with me at the table Yoira Diaz, Branch Chief for Projects Branch 1. We also have in the audience our Branch Chiefs Dennis Morey, Michael Marshall and Steve Bloom.

The staff=s Lindsay Robinson, our Safety PM, will make the staff=s presentation. She will be joined at the table by our Senior Technical Advisor Dr. Allen Hiser, Region III Lead Inspector for Byron Mel Holmberg, and Region III Lead Inspector for Braidwood Nestor Feliz-Adorno and the Safety PM Daneira Melendez.

When the staff makes its presentations,

we=ll introduce our members who will be making comments at the time. This is the ACRS Subcommittee Meeting for the License Renewal Application of Byron Station Units 1 and 2 and Braidwood 1 and 2. The SER with open items was issued on October 30, 2014 with two open items. But its resolution will be documented in the Final SER.

The first item of the open items pertains to control rod drive mechanism penetration nozzle wear due to interactions with thermal sleeve centering tabs. The second open item is in the same regard to environmentally assisted fatigue in Class I components. Both open items are summarized in the SER reviewed by the ACRS members.

Since the issuance of the SER with open items, the staff has been working very diligently on resolution of these items. In addition to these open items, the staff has been working closely with Region III inspectors to resolve issues that arose as a result of the 71002 inspections.

The staff will summarize its completed review of the open items and the issues from the inspection in the Final SER and present its findings to the ACRS full Committee. We look forward to the discussion and the review today. I=d like to turn it over to Mike Gallagher of Exelon for their presentation.

EXELON GENERATION COMPANY - BYRON STATION, UNITS 1 AND 2, AND BRAIDWOOD STATION, UNITS 1 AND 2 - BBS

MR. GALLAGHER: Okay. Thank you, Chris. Good morning. My name is Mike Gallagher and I=m the Vice President of License Renewal Projects at Exelon. I have 33 years of nuclear power plant experience all at Exelon and have been working on our license renewal project since 2006. I think we=ve seen us here from time to time.

Before we begin the presentation, I=d like to introduce the presenters. To my right is John Bashor and John is the Braidwood Engineering Director. John has over 30 years of nuclear power plant experience including the last four years at Braidwood.

To John=s right is Albert Piha. And Albert is our Mechanical Manager for the Byron-Braidwood License Renewal Project. Albert has over 32 years of nuclear power plant experience including working on Exelon=s license renewal project since 2008.

To Albert=s right is Ed Blondin. Ed is the Senior Manager of Design Engineering at Byron Station. Ed has 28 years of nuclear power plant experience including over 24 years at Bryon.

To my left is John Hufnagel. And John is our Project Licensing Lead. John has 35 years of nuclear power plant experience including working on Exelon=s license renewal project since 2005.

In addition is our technical support personnel which you see here with us today. We have with us today Mark Kanavos. And Mike is our Site Vice President at Braidwood. And we have Russ Kearney. Russ is our Site Vice President at Byron. And we have Dan Enright. And Dan is Senior Vice President of the Midwest Operations. Slide 2.

This slide shows our agenda for the presentation. We will present to you some background information on the stations and the highlights of our license renewal application. Then we=ll present to you the open items in the SER and items of interest that came from the Region III inspections.

We believe we=ve developed a robust, high quality license renewal application. We=ve developed effective aging management programs to ensure the continued safe operation of Byron and Braidwood. We appreciate this opportunity to make this presentation and look forward to answering any questions you may have.

CHAIRMAN SKILLMAN: Mike, as you begin, may I ask you please to give my colleagues and me a thumbnail view of how you=ve treated commonality versus uniqueness from the four plants and two plants.

CHAIRMAN SKILLMAN: Yes, Mr. Skillman. So we approached our reviews on a per unit basis to ensure that we captured everything on a plant-specific basis including plant-specific operating experience and so on. And the stations are very, very common.

If I can, I didn=t have it in our presentation, but I=d like to put a back-up slide we had, slide number 2. This slide is going to show you our AMR line item line-up for the Bryon-Braidwood stations. When we say station, it=s Bryon Station, Braidwood Station and then we have the two units, Unit 1 and Unit 2 of each one.

This slide is just an overview of the line item basis. I=m going to ask Dylan Cimock of our project team to go over this. Essentially, we=re trying to show that the sites are very, very common. Dylan.

MR. CIMOCK: Dylan Cimock, License Renewal Team. Just to expand on what Mike said, the way we approached the scoping, screening, AMR, operating experience review was on a unit-by-unit basis. We looked at the individual P&IDs, pipe and instrument diagrams, for each individual unit, established our scoping boundaries, accounted for each individual component type, its functions, materials and environments. Where differences appeared either between the units of a given station or between the stations themselves, we identified those in our scope and descriptions usually with the Byron or Braidwood only parenthetical in our application. Same thing in our aging management review tables.

So this table that we have up here on the back-up slide, when we originally submitted the application we had approximately 6400 individual AMR line items. Of those, approximately 86 percent represented no differences between the two stations or units. Fourteen percent was either a station or unit difference. And looking at that, the vast majority of these were all related to two principal differences which were differences in the clean water source or ultimate heat sink or due to replacement of the steam generators on Byron and Braidwood Unit 1 that was not done on Byron and Braidwood Unit 2.

MR. GALLAGHER: Thank you.

MEMBER POWERS: When you say there were no differences, manifestly there are differences. So there is some criterion you used in the percentage of no differences. But what are these?

MR. CIMOCK: That would depend on the aspect of the project. From a scoping standpoint, we looked at the things that, you know, the systems, structures, components that meet Part 54 rule. From an aging management standpoint, we looked for differences in component types, functions, materials, environments. From the programmatic standpoint, we looked at differences in operating experience and design to identify when we evaluate our programs whether or not new enhancements or certain acceptance would needed to be taken when comparing our programs against the GALL or ISGs.

MR. GALLAGHER: Yes. Dr. Powers, what we=re trying to show here when we say no differences which is what your question is that=s an AMR line item. So it=s a material-environment combination. We looked at each unit specifically and identified that those material and environment combinations were identical for each.

MEMBER POWERS: Manifestly, they=re not identical environments. They=re shifted in space by some distance. So there has to be some criterion.

MR. GALLAGHER: Right. But here it=s from the GALL as far as what the environment would be. You know if it=s indoor air or that type of thing. That=s what we=re saying when we say consistent with GALL. So this would be the line item consistency with the GALL.

And as Dylan said then we applied which then leads you to the aging management program to develop. And our intent is to have a common aging management program for the most part because the high number of line items are common that=s achievable. Did we answer your question, Mr. Skillman?

CHAIRMAN SKILLMAN: It did for me. Dr. Powers?

MEMBER POWERS: Well, the problem that I see is yes, this is inside. It=s in the air and whatnot. I=m sure that the temperature of the air it was exposed to was different. The air flow over it was different.

But there has to be some point at which you say those differences -- maybe small -- just didn=t amount to anything significant.

MR. GALLAGHER: And I think the way that=s borne out is in the operating experience. So we did a plant-specific operating experience review.

MEMBER POWERS: There you go.

MR. GALLAGHER: And then that=s how we detected it.

MEMBER POWERS: So they=re based on a combination of engineering judgment. Two-tenths of a degree just doesn=t make any difference.

MR. GALLAGHER: And our review of operating experience.

MEMBER POWERS: We looked at the operating experience and we found out that the thing had screwed up in exactly the same way every time at the same place.

MR. GALLAGHER: And where there were differences in operating experience, we factored that into our programs.

CHAIRMAN SKILLMAN: Thank you. Let=s continue.

MR. GALLAGHER: So now let me turn the presentation over to John Bashor. John.

MR. BASHOR: Thank you, Mike. Slide 3 please. Good morning. My name is John Bashor. I=m the Engineering Director at Braidwood Generating

Station.

Let me first explain our presentation=s color coding. We have a gray highlighted header on slides we=re presenting on information that is common to both stations. For Bryon-only information, the header or information is highlighted in green and for Braidwood only blue.

Bryon and Braidwood Stations= Units 1 and 2 are Westinghouse pressurized water reactor, four-loop designs that are owned and operated by Exelon. The Bryon Generating Station is located in the State of Illinois approximately 95 miles northwest of Chicago. And the Braidwood Generating Station is located in the State of Illinois approximately 60 miles southwest of Chicago. Slide 4 please.

This slide shows an overview of the Byron Generating Station. On this slide, you can see the containment structures, the auxiliary building and the turbine building which are located in the center of the picture. The circulating water cooling towers and flume, the circulating water pump house, the independent spent fuel storage installation, the 345 kV switchyard and the essential service water cooling towers which are the station=s ultimate heat sink.

CONSULTANT BARTON: May I ask you a question about the switchyard? Is a lot of the equipment in the switchyards for SBO and is maintenance done in the switchyards?

I=m sure the plant staff is not doing the maintenance in the switchyard. Someone else is. And who is that?

MR. GALLAGHER: We have a person here, Doug Overbeck. Doug, you can answer that question.

MR. OVERBECK: Doug Overbeck, Braidwood Station Plant Engineering. The maintenance in the switchyard is performed by Commonwealth Edison personnel.

MR. GALLAGHER: Is that microphone on? Sorry.

CONSULTANT BARTON: Thank you. Now my question is when those people want to go into the switchyard and do work, how is the plant involved? I know the plant has to oversee in some respect to that work since it is vital to plant operation.

MR. GALLAGHER: Yes, and Doug can tell you about the controls we have.

MR. OVERBECK: The process is that Commonwealth Edison submits work requests to the station and the station provides work orders and put it in our process. They=re put in the schedule. They=re evaluated for risk and time of execution. Operations has to approve the work order. They also approve access to the switchyard.

CONSULTANT BARTON: Thank you.

MR. GALLAGHER: Thank, Doug.

John.

MR. BASHOR: Slide 5 please. This slide shows an overview of the Braidwood Generating Station. On the slide you can see the containment structures, the auxiliary building and the turbine building which are located in the center of the picture. The lake screen house, the independent spend fuel storage installation, the 345 kV switchyard and the cooling pond which contains the station=s ultimate heat sink.

As you can see from these station overviews with the exception of the cooling water source, the physical and design characteristics of the two stations are essentially identical. Slide 6 please.

This slide provides an overview of Byron and Braidwood histories and some major station improvements. Byron was initially licensed in 1994 for Unit 1 and 1986 for Unit 2. Braidwood was initially licensed in 1986 for Unit 1 and 1987 for Unit 2. All four units were initially licensed for a rate of thermal power of 3,411 megawatts thermal (MW_t).

A five percent increase in rated power on all four units was performed in 2001. In April of this year a 1.63 percent measurement uncertainty recapture (MUR) power uprate was implemented which increased the thermal rating on each unit to their current rating of 3645 MW_t. Exelon has also continued to make substantial improvements to both Bryon and Braidwood units such as steam generator replacements on Byron Unit 1 and Braidwood Unit 1, emergency core cooling system (ECCS) recirculation sump screen modifications, spent fuel rack replacements and independent spent fuel storage installations (ISFSI).

Byron and Braidwood are operated on 18-month fuel cycles and ASCE factor for this year as of the third quarter is greater than 95 percent for each station.

The renewal application was submitted on May 29, 2013. Our current license at Byron expires on October 31, 2024 for Unit 1 and November 6, 2026 for Unit 2. Our current licenses at Braidwood expire on October 17, 2026 for Unit 1 and December 18, 2027 for Unit 2.

I will now turn it over to Albert Piha who will present to you the highlights of our license renewal application.

CHAIRMAN SKILLMAN: Before you change, keep that slide. John, go ahead.

CONSULTANT BARTON: You change out steam generators on Unit 1 at both sites. Unit 2 has the original steam generators. Is there any plan that you see now for replacement of steam generators in Unit 2 at both sites?

MR. BASHOR: If you look at the long range plan, Mr. Barton, you will see steam generator replacement out in the out years.

CONSULTANT BARTON: We currently do not have active projects that are underway for either Byron or Braidwood actively pursuing that. But we are constantly monitoring the results of the inspections we do on the steam generators at both Byron and Braidwood. And we realize that if we run into a situation where we see accelerated plugging of tubes we may find ourselves in a situation where replacement will be required in the future.

CONSULTANT BARTON: Okay. You=re kind of

lucky because I know a lot of plants have changed out Westinghouse steam generators.

MEMBER BALLINGER: You=re one of the two unusual ones.

MR. GALLAGHER: The Unit 2 had better materials originally in the original construction. The Unit 1 did not. And that=s really the difference there.

CONSULTANT BARTON: Unit 1 was also B&Ws, right?

MR. BASHOR: Unit 1s are B&W. They were all original Westinghouse.

CONSULTANT BARTON: Okay. I gotcha.

CHAIRMAN SKILLMAN: Let me ask my question please. Reviewing the AMPs and this is steam generator program B.2.1.10 directed specifically at Bryon, the wording in the inspector=s report is AFor the second enhancement applicable to Byron Unit 1 steam generators, the existing AMP will be enhanced to validate that the PWSEC of the tube sheet welds is not occurring.@ That=s in the inspection report.

I do not have the inspection report results for Braidwood Unit 1 which is also a B&W steam generator design. Is that same AMP applicable to Braidwood Unit

1?

MR. BASHOR: Yes sir. Is the steam generator -- Where is that at?

CHAIRMAN SKILLMAN: That=s what I=m asking. There=s an enhancement on Byron 1 steam generators that I=m wondering if that same enhancement is applicable to Braidwood.

MR. BECKNELL: I=m Gary Becknell, License Renewal Project Team. The enhancement is applicable to both stations, Byron and Braidwood, for the verification that water chemistry is controlling primary water stress corrosion cracking.

CHAIRMAN SKILLMAN: Yes sir. Thank you. Thank you, Mike.

MEMBER RICCARDELLA: Just another question. What are your plans with respect to the reactor vessel top heads at Byron and Braidwood?

MR. BASHOR: Right now, we find ourselves in a unique situation, Dr. Riccardella. We have not replaced the heads at Byron or Braidwood. I would like to have Jack Feimster stand up and give a summary of what we=re doing in that area specifically looking at a mitigation strategy we=re putting in place in the future.

MR. FEIMSTER: I=m Jack Feimster, Senior Engineering Manager at Byron Station. Currently, Exelon is pursuing a mitigation strategy for reactor vessel heads. Specifically in our particular case, we=re pursuing peening of the affected area. The company we have chosen is AREVA. We=re going to use what are water jet cavitation peening.

MEMBER RICCARDELLA: Thank you.

MR. GALLAGHER: Thanks, Jack.

MR. BASHOR: I will now turn it over to Albert Piha who will present to you the highlights of our license renewal application.

MR. PIHA: Thank you, John. Slide 7 please. Good morning. My name is Albert Piha and I am the Byron and Braidwood License Renewal and Mechanical Manager. I will discuss the highlights of our license renewal application including the aging management programs, commitments and an overview of the two open items in the SER. Slide 8 please.

In preparing the application, Exelon used industry and NRC guidance to make the application as consistent with the GALL as possible. Our submittal was based on GALL Revision 2. There are 45 aging management programs at Byron and 44 at Braidwood.

The difference in the number of the aging management programs is due to the fuse holder program which is applicable to Bryon only. They are safety-related equipment found only at the Byron River screenhouse that required the application of this aging management program.

Thirty-eight Byron programs and 37 Braidwood programs are consistent with the GALL. Seven programs at each station have exceptions to the GALL. There are 47 license renewal commitments at Byron and 46 at Braidwood. Of these commitments, 45 at Byron and 44 at Braidwood are associated with aging management programs.

In addition, one common commitment at each station implements the operating experience program enhancements. The final commitment for each station is to restore the out-of-service reactor vessel stud on Byron Unit 2 and on Braidwood Unit 2 no later than six months prior to entering the period of extended operation.

These commitments will be captured within the license renewal UFSAR supplement and the Station Commitment Tracking Database and managed in accordance with 10 CFR 50.59 and the Commitment Management Program which is based on the NRC endorsed NEI 99-04 process.

CHAIRMAN SKILLMAN: Would you like to comment on Byron 2 stud 11 please?

MR. PIHA: Yes. Byron Unit 2 stud was successfully removed last fall in October and a new stud was installed and all 54 studs are tensioned and in service.

CHAIRMAN SKILLMAN: Yes sir. So that leaves the one stud 35 on Braidwood 2 as a commitment prior to PEO.

MR. PIHA: That=s correct.

CHAIRMAN SKILLMAN: Okay. Thank you.

CONSULTANT BARTON: While you=re on it, do you currently have a plan of how you=re going to do stud 35 since it=s not just threads that are messed up. You have a larger hole on that head.

MR. GALLAGHER: Yes, that=s going to take us a little more work, Mr. Barton. What we=re doing is next outage we=re going to be taking -- We attempted a repair in 2002 as you know.

CONSULTANT BARTON: Yes.

MR. GALLAGHER: And it was -- There was a problem with the machine. And it was over bored at the time.

CONSULTANT BARTON: Right.

MR. GALLAGHER: So we want to take detailed measurements. We want to know exactly what=s down there and develop a modification and in a subsequent outage install it. Our commitment is to get it done before as Albert said six months before PEO. But we=re making good progress already. We did the one at Byron and we=re pursuing the one at Braidwood.

CONSULTANT BARTON: You=ve got until the license extension starts.

MR. GALLAGHER: Yes.

CONSULTANT BARTON: And in my mind when do you have that kind of thing planned out? Is it the last outage before you go into -- which takes it to the difficulty maybe?

MR. GALLAGHER: No. Our intent is to move forward with this. And as I said, we did on Byron Unit 2. We took care of that.

CONSULTANT BARTON: Right. But that was a lot easier fix.

MR. GALLAGHER: Yeah, but that was the one that had the aging management question because you had the stud, partial stud, in there.

CONSULTANT BARTON: Right.

MR. GALLAGHER: And so getting it out was a big win. We were able to put a new one in. On Braidwood, we=ve got to get the measurements and the design that we know is going to work and then move forward with that.

MEMBER STETKAR: You don=t have it scheduled.

MR. GALLAGHER: No, we=ll get the measurements next outage. Then from there we=ll plan what we need to do. Okay.

All right, Albert.

MR. PIHA: Slide 9 please. There are two open items in the Byron and Braidwood SER. Slide 10.

The first open item is associated with the screening methodology for environmentally assisted fatigue (EAF) to determine leading locations Leading locations are those locations which have been determined to bound all other locations for consideration of environmental fatigue.

Monitoring these locations for the period of extended operation will ensure no location will exceed an environmental fatigue usage factor of 1.0. This includes consideration of both the NUREG-6260 locations to determine appropriate for a new

Westinghouse PWR and those locations determined could be more limiting than the 6260 locations.

Leading locations were determined by comparison of environmental fatigue experienced at locations in transient sections. A transient section is defined as a grouping of equipment or piping experiencing the same transients.

The NRC staff has requested more information in three areas. The first area is concerned with the staff=s request for additional justification that the leading material locations will continue to bound eliminated locations after refined analysis. Assessment of the relative differences in screening environmental fatigue usage results, the relative differences in the conservatism in a stress analysis and the potential variation in the environmental correction factor justified a determination of the leading material location. With a refined analysis, leading locations are evaluated with both improved analysis techniques and a review of their inputs.

Considering refined analysis, it was shown the leading locations will continue to bound the eliminated material locations. The result of this analysis is the establishment of limits for the fatigue monitoring program to assure environmental fatigue is managed during the period of extended operation.

For the second area, the staff requested justification why the Bryon and Braidwood Unit 1 replacement steam generator location was removed from consideration as a leading location when its screening environmental fatigue usage factor was higher than the location selected as the leading location. Because of the conservatism in the stress analysis for this location, it was shown that the steam generator location has a screening environmental fatigue usage lower than the leading location when it points similar conservatism in the stress analysis.

In the third area, the staff requested identification of other instances where a component location was removed from consideration which had a higher screening environmental fatigue usage factor than the location selected to be the leading location. Two other locations in the piping systems were identified and had the same justification as the steam generator location.

To resolve this issue, we have provided the additional information to the staff in a letter dated November 25, 2014.

CHAIRMAN SKILLMAN: Albert, before you move from that slide, would you make a comment to my colleagues and me about what it actually takes for a utility to do an environmental CUF calculations? Is this something that you do on your own? Is it something you go out and buy a specialty contract for? How is this work conducted and what=s the impact on your staff?

MR. PIHA: For us, on this project, we did contract an outside consultant to do this work for us. We have a TLAA engineer who is involved, interfaces and reviews and comments on all the work that=s done by the contractor.

CHAIRMAN SKILLMAN: So it=s really handled under the TLAA portion of license renewal.

MR. PIHA: That=s correct.

CHAIRMAN SKILLMAN: Thank you.

MEMBER RICCARDELLA: We just sat through a meeting yesterday on the revisions to Reg Guide 1.207 and the NUREG-6909 which is changing these environmental things somewhat. I think in general they become less onerous. But are there plans to incorporate those new revisions in, too?

MR. PIHA: I=m going to let Tom Quintenz, our TLAA engineer, speak to that.

MR. QUINTENZ: Tom Quintenz, License Renewal Project. I believe your question had to do with the new Reg Guide 1.207 that is in draft right now.

MEMBER RICCARDELLA: Yes.

MR. QUINTENZ: And I think you were asking about the encumbrance of the new draft guide.

MEMBER RICCARDELLA: Yes. Are you planning to address that?

MR. QUINTENZ: My understanding is that it=s employing NUREG-6909 as the guide for doing the environmental fatigue. Basically, we=ve done our calculations for the nickel locations using 6909. So we have experience with that.

MEMBER RICCARDELLA: But that=s a 6909 Rev 1 that I=m thinking of.

MR. QUINTENZ: That=s correct. That=s still under review. We understand that.

MEMBER RICCARDELLA: Do you have future plans for that new methodology?

MR. QUINTENZ: We would have to. We=re a part of the industry comment on both of those items. I think we would be awaiting to see what the results of that would be.

MEMBER RICCARDELLA: Okay. Thanks.

MEMBER BALLINGER: When you said monitoring the fatigue locations, can you expand on that just a little bit?

MR. PIHA: I=ll have Tom also answer that question.

MR. QUINTENZ: Tom Quintenz, License Renewal Project. This involves basically monitoring the transients which are inputs to the fatigue analysis. So when we say we are monitoring the location, we=re actually monitoring the transients which were inputs to the fatigue analysis for that location.

MEMBER BALLINGER: When you say monitoring, you mean measuring the temperature and things like that or just.

MR. QUINTENZ: Yes, we basically look for the transient and we characterize the temperature and pressure profiles to make sure that they agree with the design inputs that were with the fatigue analysis.

MEMBER BALLINGER: When you say characterize, you mean measure it or calculate.

MR. QUINTENZ: Measure.

MEMBER BALLINGER: Okay.

CHAIRMAN SKILLMAN: Pete and Ron, are you good?

MEMBER BALLINGER: Yes.

MEMBER RICCARDELLA: I=m good.

CHAIRMAN SKILLMAN: Go ahead, Mike. Or excuse me. Go ahead, Albert.

MR. PIHA: Slide 11 please. The second open item involves the aging management of the control rod drive mechanism or CRDM housing for wear due to thermal sleeve rotation. The CRDM housing is managed by the ASME Section XI, Subsections IWB/IWC/IWD Aging Management Program.

The NRC staff has requested more information in two areas, the results of the CRDM Housing Wear Analysis and also the CRDM Housing Wear Acceptance Criteria. Our presentation will provide background information on the CRDM Housing wear and will address the areas where the NRC staff had requested more information. The additional information will address this open item. It has been submitted to the NRC staff for their review in a letter dated November 24, 2014.

I will now turn the presentation over to Ed Blondin who will discuss the CRDM Housing wear.

MR. BLONDIN: Thank you, Albert. Slide 12 please. Good morning. My name is Ed Blondin. I=m the Senior Manager of Design Engineering at Byron Station.

On this slide, a cross section of the reactor vessel head is shown with the control rod drive mechanism housings or CRDM housings shown in blue. Inside these housings is a thermal sleeve which is illustrated in green. At Byron and Braidwood, the reactor vessel heads have thermal sleeves installed in 55 of the 78 CRDM housings. The CRDM housings are part of the reactor coolant pressure boundary and are made of nickel alloy in the area of interest.

The thermal sleeve --

MEMBER BALLINGER: Six hundred or 625 or 690? What do you mean by nickel alloy?

MR. BLONDIN: Phil.

MR. O=DONNELL: Phil O=Donnell, License Renewal Team. They=re at alloy 600.

MEMBER BALLINGER: Six hundred, okay.

MR. O=DONNELL: Yes.

MEMBER RICCARDELLA: That=s related to my earlier question about the reactor vessel head. But this is a wear problem. This isn=t a cracking problem.

MEMBER BALLINGER: Yes.

MR. BLONDIN: The thermal sleeves are loosely inserted into the CRDM housings and are not physically attached. The thermal sleeves are approximately 60 inches in length. There are three centering tabs shown in black 120 degrees apart located approximately 22 inches below the top of the thermal sleeve. The thermal sleeve centering tab material is stainless steel.

Thermal sleeves are used to mitigate the effects of reactor coolant temperature in the upper reactor vessel head region on the control rods. The thermal sleeves also provide a means of guiding the control rods into the housing following refueling operations. Rotation of the thermal sleeves within the CRDM housing occurs due to normal operation from reactor coolant flow in this region.

CHAIRMAN SKILLMAN: What is the propellant that causes the rotation? If you can describe the force diagram for us, that would help.

MR. BLONDIN: Go ahead, Phil.

MR. O=DONNELL: Phil O=Donnell, License Renewal Team. Because it=s a T-cold head, there is a substantial amount of coolant flow, approximately three percent, that ends up going through that particular region. And since the thermal sleeves are not fixed, they actually -- the flow past them causes it to rotate.

MEMBER BALLINGER: How are the tabs attached? By welding?

MR. O=DONNELL: They are attached by welding. That is correct.

MEMBER BALLINGER: And so then I come back to the alloy 600 issue. Is it thermally treated or is it just a tubing that=s extruded and no particular heat treatment like you would have in a steam generator tube?

MR. O=DONNELL: I would have to get back to you on that.

MR. GALLAGHER: George, do you know?

MR. O=DONNELL: We can get back to you.

MEMBER BALLINGER: Because I=d be more than worried about -- It=s not a stress component. It=s not a pressure boundary. But that weld point is a point of high residual stress. And it goes all the way around or is it just tabs.

MR. O=DONNELL: They=re just tabs.

MEMBER BALLINGER: They=re just tabs,

okay.

MR. O=DONNELL: Phil O=Donnell, License Renewal Team. The tab is stainless steel.

MEMBER BALLINGER: Yes, but it=s welded to the 600.

MR. O=DONNELL: No, no. The tab is on the thermal sleeve.

MR. BLONDIN: The thermal sleeve are stainless steel.

MEMBER BALLINGER: Oh, I thought I heard you tell me that the thermal sleeve was alloy 600.

MR. O=DONNELL: No, the housing.

MEMBER BALLINGER: All right. Now I=m oriented properly.

MEMBER RICCARDELLA: And the cooling flow you=re referring to is in that annulus between the thermal sleeve and the housing or no?

MR. O=DONNELL: Phil O=Donnell, License Renewal Team. It is past the thermal sleeves. It is not going up into that region. It basically goes down the head.

CHAIRMAN SKILLMAN: So the rotating force is the friction from the T-hot coming over the top of the head.

MR. O=DONNELL: It=s actually T-cold.

CHAIRMAN SKILLMAN: T-cold.

MR. O=DONNELL: Yes.

CHAIRMAN SKILLMAN: So it=s a friction on the -- What=s it called?

MR. BLONDIN: The thermal sleeve.

CHAIRMAN SKILLMAN: The thermal sleeve.

MR. O=DONNELL: Yes.

CHAIRMAN SKILLMAN: And it=s just the turbulent flow on the top of the head that=s causing these things to rotate.

MR. O=DONNELL: That is correct.

CHAIRMAN SKILLMAN: Is this a phenomenon that is common to the four LOOP Westinghouse plants?

MR. O=DONNELL: This is common to Westinghouse plants.

MR. PIHA: We=re going to discuss about a report that=s been completed. And it was done for participating utilities in the industry for the same situation.

CONSULTANT BARTON: This is the first time I think we=ve heard this problem though.

CHAIRMAN SKILLMAN: It=s the first time I=ve heard of it.

CONSULTANT BARTON: Yes.

CHAIRMAN SKILLMAN: It could be others have heard of it. But I certainly haven=t.

CONSULTANT BARTON: I mean as far as seeing other plant renewals, Westinghouse units, this has not come up.

CHAIRMAN SKILLMAN: I don=t remember this from the last meeting.

MEMBER BALLINGER: Now these are T-cold heads, all of them. So that puts the susceptibility to J-groove problems way, way down.

CONSULTANT BARTON: Yes, it drops the temperature. Except they=ve had a few leaks here at a couple of these plants.

MEMBER BALLINGER: I know. That was my next question.

CONSULTANT BARTON: Relatively few. It=s some of them are from that unique Cuban material that has unusual susceptibility.

CHAIRMAN SKILLMAN: Let me ask this. Is this a phenomenon that began --

MEMBER RICCARDELLA: Right. They hadn=t had the cracks. I=m sorry. I misspoke.

CHAIRMAN SKILLMAN: Is this a phenomenon

that has occurred since you did your power upgrades? Did it exist before then or is it new after the power upgrade?

MR. GALLAGHER: The phenomenon is believed to have existed --

CHAIRMAN SKILLMAN: From the very beginning?

MR. GALLAGHER: -- from the very beginning. The reason that there=s information on this now and that there=s an industry initiative to investigate this is because when you do the J-groove weld inspections you can see in the ones that are at the center, the centering tabs are near the J-groove weld. So you can see this scratching pattern.

CHAIRMAN SKILLMAN: Right.

MR. GALLAGHER: So that=s why it=s come up fairly recently in the industry. And as Albert said, there=s a PWR owners group analysis. George Demetri is here. He=s the Westinghouse author of the analysis.

And we=re going to go through the details for you here with what we=re trying to show you and I hope we corrected your mental image.

MEMBER BALLINGER: I thought somebody said alloy 600 for the sleeve.

MR. GALLAGHER: Yes. If we could just go to the next slide for a minute because we have a closer thing in here. Yes, just for clarity, the thermal sleeve is stainless steel. The tab is on the thermal sleeve and it wears on the nozzle. And Ed will get into the rest of this.

MEMBER RICCARDELLA: The wear is in the alloy 600.

MR. GALLAGHER: Yes. And that=s the area that is a pressure boundary. And that=s why we have reviewed this and have this analysis.

MEMBER BALLINGER: So the required under head inspection plan when you get that tab very close to the top of the J-groove walls at the center, is that looked at as a possible initiation point for cracking? The stresses from the J-groove weld might get far enough above so that they=re in a region where that wear pattern might influence things.

MR. GALLAGHER: George can answer that.

MR. DEMETRI: George Demetri with Westinghouse Electric Company. We don=t consider that. It=s considered, we analyze it as a wear phenomenon and we did account for stress concentration, stress intensification there.

MEMBER BALLINGER: On the initial of the alloy 600?

MR. DEMETRI: Yes, that=s correct.

MEMBER BALLINGER: Okay.

MEMBER RICCARDELLA: How close does it get to the J-groove weld on the top dead center?

MR. DEMETRI: It could be -- It could actually span the top of the J-groove weld.

MEMBER BALLINGER: Okay. So that=s right in the region.

MEMBER RICCARDELLA: But it could be in the residual stress weld.

MR. DEMETRI: Residual stress in that weld.

MEMBER RICCARDELLA: But I mean they=re inspecting for cracks.

MEMBER BALLINGER: Yes, but there=s an under head inspection plan.

MEMBER RICCARDELLA: Right.

CHAIRMAN SKILLMAN: I think we=re going to hear more about that in a few minutes.

MR. GALLAGHER: Yes. So at this point and basically to fast forward a little bit what we=re trying to show here is that you can wear the complete thickness of the tab and it=s still acceptable. And Ed will get into the details. Ed.

MR. BLONDIN: Okay. So as we started to talk about, it is common to the Westinghouse PWR design and it=s been recently evaluated by Westinghouse for the PWR owners group using finite element analysis.

MEMBER STETKAR: Ed, if we could before you get into the analysis, to follow up on something John raised, are Byron and Braidwood the first plants to observe this wear? I mean I=m curious why we haven=t heard about it in any of the others. We heard about license renewals for several Westinghouse plants over the last seven years I=ve been in the Committee. This is the first one where it=s come up.

MR. BLONDIN: Phil, do you know what other plants?

MR. O=DONNELL: This is Phil O=Donnell, License Renewal Team. Actually, in the last one that you did with TVA, that was also in the SER.

MEMBER STETKAR: It was. I missed it.

MR. O=DONNELL: Yes.

MEMBER STETKAR: But it wasn=t challenged by anybody in the review.

MR. O=DONNELL: That=s correct.

CHAIRMAN SKILLMAN: But before then it was not a -- At least it was not communicated.

MR. O=DONNELL: It was not communicated because they were also I believe going --

MR. GALLAGHER: There=s difference here, Mr. Skillman. We don=t want to talk about other plants.

CHAIRMAN SKILLMAN: Right. I understand. I was just curious. That=s why I asked Westinghouse.

MR. GALLAGHER: Some of the plants with newer heads don=t have the phenomenon because there are some design differences.

CHAIRMAN SKILLMAN: Okay.

MR. GALLAGHER: So it=s not -- it=s basically we have this and many other plants have it. But we can=t go on a case-by-case basis.

CHAIRMAN SKILLMAN: All right. Thank you.

MR. BLONDIN: I=ll continue. The analysis examined the impact of the hypothetical maximum wear depth on the integrity of the CRDM housings.

CHAIRMAN SKILLMAN: And the maximum wear depth is the entire thickness of that tab into the primary coolant system pressure boundary ID.

MR. BLONDIN: That is correct. And I=ll talk more about that in a moment.

CHAIRMAN SKILLMAN: Okay.

MR. BLONDIN: Based on the analysis, it was it was also determined that if the maximum hypothetical wear depth is assumed the CRDM housings will continue to meet the ASME Code requirements and the current licensing basis.

MEMBER BALLINGER: Okay. I=ll keep harping on this. But at the maximum depth, you have margin on crack growth if you initiate a stress corrosion crack growth rate. Or are you just saying AWe=re not going to initiate a crack growth because we=re going to peen it or something@?

MR. DEMETRI: George Demetri, Westinghouse Electric. We just analyzed it as a wear phenomenon, but we have not looked at it from the standpoint of crack growth.

MEMBER BALLINGER: I think somebody should.

CHAIRMAN SKILLMAN: Let=s proceed.

MR. BLONDIN: Okay. Details are further explained on the next slide, slide 13 please. The expanded view of the CRDM housing area prone to wear was shown is shown in the detail on this slide. When the thermal sleeve rotates within the CRDM housing the centering tabs again shown in black rub against the CRDM housing and cause wear at the centering tabs and the housing. The wear is not evenly distributed within the inside diameter of the CRDM housing due to the flow induced vibration on the thermal sleeves.

The hypothetical maximum possible wear depth of the CRDM housing at the thickness of the centering tab is 0.1075 inch. Assuming that the maximum possible wear depth was to occur, the CRDM housing thickness would be reduced from the original 0.625 inch to 0.517 inch. However, based on the similarity and hardness of the metals with the nickel alloy housing and the stainless steel centering tabs the CRDM housing and the thermal sleeve tabs will both experience wear. Therefore, the actual wear on the CRDM housing is expected to be substantially less than this worst case assumption. Slide 14 please.

The detailed ASME Code evaluation which includes finite element analysis and stress calculations was performed by Westinghouse that considered the effects of the maximum wear depth on the integrity of the CRDM housing. As stated earlier, several Westinghouse PWRs have discovered similar wear indications on the CRDM housings.

Primary stress evaluations were performed using classical stress equations. Primary plus secondary stress integrity ranges and fatigue usage factors were determined by finite element analysis. The CRDM housings were evaluated for the design, normal, upset, emergency, faulted and test conditions as required by the ASME Code. The evaluations also considered the UFSAR design requirements with respect to transients, loading and allowable stresses. The analysis demonstrated that the CRDM housing with the maximum possible wear group depth of 0.1075 inch satisfies all of the allowable stress and fatigue limits for Section III, Subsections NB-3221 through NB-3226 of the ASME Code.

Since the analysis considered a conservative set of enveloping mechanical loads and pressure and thermal transients as well as a highly unlikely wear group depth of 0.1075 inch, the CRDM housing with inside surface wear is acceptable. Additionally, the Byron and Braidwood 40 year design basis transients were analyzed to determine if the number of cycles was bounding for the 60 year period.

Based on the review, the 60 year design basis transients set for the period of extended operation is bounded by this CRDM housing analysis. Slide 15 please.

In summary, the applicable ASME Code limits for Class 1 for reactor coolant pressure bounded components have been utilized in our analysis. And the CRDM housing was evaluated as acceptable for the period of extended operation. As the Byron and Braidwood 40 year design basis transients have been shown to be bounding for the 60 year design basis transient set, then this analysis is also valid for the period of extended operation.

The CRDM housing wear acceptance criteria as prescribed in ASME Section III, including the fatigue analysis, have been met for the impact of the hypothetical maximum tab wear on the inside of the CRDM housing. No additional actions are required for aging management of the CRDM housing wear. This concludes our presentation for the CRDM housing wear open item.

At this time, I would like to turn the presentation over to Albert Piha to introduce our items of interest from the Region III inspections.

CHAIRMAN SKILLMAN: Before we change the

slide on that third bullet, those words after the parenthesis, Ano additional aging management activities,@ does that communicate no inspections?

MR. PIHA: That=s correct.

CHAIRMAN SKILLMAN: Is that your intent not to look at it?

MR. PIHA: That=s correct.

CHAIRMAN SKILLMAN: Don=t you think at some point in the future you ought to take a look to confirm?

MR. PIHA: Today there isn=t a qualified technique to look at this area. But this analysis says that we could have full wear depth and we meet all code limits and acceptance criteria.

CHAIRMAN SKILLMAN: Is the process to inspect the pressure housing portion of the stump of the control rod drive extension a process the requires removal of the control rod drive and then removal of the sleeve? Is that what it takes to do that inspection?

MR. PIHA: George, do you have an answer?

MR. DEMETRI: Yes, George Demetri, Westinghouse. You would definitely need to remove the thermal sleeve to do that inspection.

CHAIRMAN SKILLMAN: But does a thermal sleeve withdraw if the mechanism is removed? Or is it blocked because of its geometry below the inside portion of the --

MR. DEMETRI: Yes, it=s blocked because of the funnel.

CHAIRMAN SKILLMAN: So it really cannot be pulled through.

MR. DEMETRI: That=s correct.

MEMBER RICCARDELLA: Let=s talk about the ones that are near top dead center that are close to the J-groove weld. When you inspect the J-groove weld, you don=t remove the sleeve, right? You have something that goes in the annulus I believe. So for at least those penetrations you can get in the vicinity of this wear, right?

MR. DEMETRI: Phil, can you answer?

MR. O=DONNELL: Phil O=Donnell, License Renewal Team. Yes, basically when they do the J-groove weld inspections they have a probe that goes up between the thermal sleeve and the CRDM housing to look at that. But what they have found though is that there is not a qualified method right now to determine the wear depth of any crack beyond that particular point.

MEMBER RICCARDELLA: I understand that, but to address the concern that Ron brought up is if you=re getting any stress corrosion cracking around here at least on those penetrations I think you would see it. And my understanding is those inspections, are they every outage for these because you=ve had cracking?

MR. O=DONNELL: Phil O=Donnell, License Renewal Team. For three of the plants it is because of the cracking of the J-groove welds. They actually do the inspections once per cycle. Braidwood Unit 2 is not currently -- has no signs of cracking yet. So it=s every three to four to five cycles right now.

MEMBER BALLINGER: So these are being -- Those areas that you=re going to --

MEMBER RICCARDELLA: Are being inspected for stress corrosion cracking and crack growth. And there have been crack growth analyses done to support those inspections.

MR. GALLAGHER: Oh yeah.

MEMBER RICCARDELLA: Of the J-groove welds. Well, also the tubes in the vicinity of the J-groove wells and at the top of the J-groove welds. The only question I think that Ron raises is should you consider the effect of this wear on those crack growth analysis. You know you=ve got a 10 percent loss of --

MEMBER BALLINGER: It=s not so much crack growth as it is initiation. You know the wear affects the initiation time.

MEMBER RICCARDELLA: Yes.

CHAIRMAN SKILLMAN: Please proceed. Thank you.

MR. PIHA: Slide 16 please. So there are three items of interest that were realized during the Region III inspections at Byron and Braidwood. These items are being discussed to acknowledge the issues that were raised and to provide reassurance that effective aging management activities will be performed on these in-scope components during the period of extended operation.

The items of interest are visual examination of concrete containment structures applicable to both Byron and Braidwood Stations, the CRDM seismic support assembly aging management applicable to both Byron and Braidwood stations and also the Braidwood Flux Thimble Tube Inspection Program. Slide 17 please.

CONSULTANT BARTON: Let me ask you. Can I ask you a question on this concrete thing? You did repair the dome. That has been repaired. The concrete and the drainage issue on the dome has been repaired.

MR. PIHA: Yes.

CONSULTANT BARTON: Now how are you observing the repair of the dome? I can understand when you=ve got it below the dome. You can whatever. But what are you doing for inspection of the dome to make sure that you don=t initiate additional issues on the dome?

MR. PIHA: I=ll have either Jim or Tim. Tim Johnson.

MR. JOHNSON: My name is Tim Johnson, Braidwood Engineering Programs. To review repair on the dome, the classification is this is the dome surface, correct?

CONSULTANT BARTON: Correct.

MR. JOHNSON: At Braidwood.

CONSULTANT BARTON: Right.

MR. JOHNSON: The repairs we=ve done on those about 10 years ago were cosmetic. Where was no reinforcing steel, we basically patched them and recoated them with epoxy. We monitor them every year and to this point they=re performing very well. No problems.

CONSULTANT BARTON: Thank you.

MR. PIHA: The first topic I=ll address is associated with the visual examination of the concrete containment structures under the ASME Section XI, Subsection IWL, Aging Management Program.

During the NRC Region III inspection, the inspection team sought additional clarification regarding what visual resolution capability will be used to sufficiently quantify degradation to compare against the quantitative acceptance criteria described in Chapter 5 of ACI 239.3R.

To ensure that sufficient visual resolution capability will be used during the direct and remote visual examination of concrete surfaces of containment structures, Enhancement 4 of the ASME Section XI, Subsection IWL Aging Management Program has been revised to update IWL implementing procedures to require that the visual resolution capability be sufficient to detect concrete degradation at the levels described in Chapter 5 of ACI 349.3R.

CHAIRMAN SKILLMAN: Albert, would you tell us what you=re doing to accomplish that? Is this a lens system that has greater magnification and some form of calibration? Or using sonar device?

MR. PIHA: Yes, we=re using a telescope.

MR. GALLAGHER: Tim.

MR. JOHNSON: I didn=t hear that.

MR. GALLAGHER: Tim, the question Mr. Skillman had is how do we actually do inspections?

CHAIRMAN SKILLMAN: How do you really do this to make sure it=s done properly?

MR. JOHNSON: Yes, Tim Johnson, Engineering Programs Braidwood. The enhancement basically incorporates something we=ve done since the inception of IWL.

The first inspection we did was >01. And what we did because it was basically a new requirement was the industry went down to EPRI. And EPRI sponsored and recommended the use of Meade 10-inch telescope that was capable of resolution of the character card letters on the test card of the code.

What we did was physically went to the top of the containment. Braidwood and Byron are very inspection friendly if you will. There are many galleries and rooms and areas where you can get close up inspection. What we did was go up to the second gallery which just below it is the most limiting area from a distance perspective for inspection.

What we did is actually went up and measured cracks, crack widths, put simulated lines in there, measured them. There is some indication such as form ties, nails, form nails, that type of thing and actually identified those, physically measured them. We put the telescope down from different distances and angles to make sure we understood the limitations of the equipment and resolved those indications. That=s we=ve done it for the three inspections that we=ve done. And any other equipment we used, binoculars, we would do the same thing where we don=t have the limiting factors as much as we did with the telescope. We were able to resolved those characters.

Then when we did the inspections, we could conservatively size what we saw if you will. So we have a good baseline and a good repeatability through the inspections from an aging management perspective.

CHAIRMAN SKILLMAN: How are those records protected? Are they images?

MR. GALLAGHER: He wants to have a record for our specs.

MR. JOHNSON: The records are kept with

the surveillance. We=ve got the original with the inspection procedures. We also have -- Because you=re doing on a different frequency, a five-year frequency, if you will, we=ve got photographic evidence of the indications of interest if you will that we can do comparisons to for the next inspection.

CHAIRMAN SKILLMAN: Thank you.

MR. JOHNSON: You=re welcome.

MR. PIHA: This additional information has been provided to the NRC staff in a letter submitted on November 21, 2014.

CONSULTANT BARTON: The NRC inspection talked about the evidence of water seepage through concrete and concrete leaks, concrete cracks, etc., etc. And it said that through discussion with the Applicant the staff learned that this has been since initial plant construction. The question I=ve got is do we still have water leakage in this concrete causing additional cracks. Or is this one thing that happened during plant construction and never again is occurring or what?

MR. GALLAGHER: I think what=s being referred to there is the tendons tunnels at Byron.

CONSULTANT BARTON: Byron, yes.

MR. GALLAGHER: Okay. And basically there were some improvements that were made in the grading in those areas. So the water runoff is better from the containment out.

CONSULTANT BARTON: Better as in?

MR. GALLAGHER: Improved.

CONSULTANT BARTON: Has it been eliminated or?

MR. GALLAGHER: There is still some water that gets into the tendons tunnels. But the corrective action greatly reduced that. So that=s monitored as part of the structural monitoring program.

CONSULTANT BARTON: Okay.

MEMBER BALLINGER: So you think the tendons are okay.

MR. GALLAGHER: Yes.

MEMBER BALLINGER: You=re not having more problems.

MR. GALLAGHER: No, the tendons are fine.

MEMBER BALLINGER: Okay.

CONSULTANT BARTON: Thank you, Mike.

CHAIRMAN SKILLMAN: Please proceed.

MR. PIHA: Slide 18 please. The second topic I will address is aging management of the CRDM seismic support assembly. During the NRC Region III inspection at Byron Station, discussions were held with the NRC staff regarding the CRDM seismic support assemblies which were not within the scope of the ASME Section XI, Subsection IWF Aging Management Program as part of the license renewal application.

As a follow-up to the inspection, the CRDM seismic support assembly was added to the scope of the IWF program. Slide 19.

This slide shows a sketch of the assembly called the Integral Head Assembly which includes the CRDM seismic support assembly as a sub-element. The reactor vessel head is at the bottom of the sketch.

The items that comprise the CRDM seismic support assembly are highlighted in green. The CRDM seismic support assembly consists of the shield assembly, the connecting lift rod assemblies, and seismic tie rod assemblies.

At Bryon and Braidwood, the integral head assembly which was supplied by Westinghouse is a large mechanical assembly which sits on top of the reactor vessel head and combines all of the equipment on top of the reactor head into an efficient, one-package reactor vessel head design. During plant operation, the integral head assembly is braced to the wall of the refueling cavity by the seismic tie rod assemblies. Slide 20.

The CRDM seismic support assembly is a sub-element of the integral head assembly. All elements and sub-elements of the integral head assembly were evaluated for aging management in the original license renewal application. The External Surfaces Monitoring and Boric Acid Corrosion Aging Management Programs were credited in the LRA for visual inspections of all of the elements of the integral head assembly including the CRDM seismic support assembly as a sub-element.

During the NRC Region III inspection at Bryon, the NRC staff questioned the aging management of the CRDM seismic support assemblies which were not within the scope of the IWF program as part of the license renewal application. After discussions with the NRC staff, Exelon determined it was appropriate to add the CRDM seismic support assembly to the scope of the IWF program for license renewal aging management.

As a result, the CRDM seismic support assembly consisting of the shield assembly, three lift rod assemblies and six seismic tie rod assemblies was added to the scope of the IWF program. The external surfaces monitoring, boric acid corrosion and the IWF programs well address aging of the CRDM seismic support assembly. Under the IWF program, a visual VT3 examination of the CRDM seismic support assembly will be performed. Exelon has provided this information to the staff to address this issue in a letter submitted on August 29, 2014.

The staff also asked if high strength bolts were used for the CRDM seismic support assembly. Exelon has confirmed that there is no high strength bolting installed and has provided this information to the staff in a letter submitted October 16, 2014. Slide 21.

At this time, I would like to turn the presentation over to John Bashor for the discussion of the third and final topic, the Braidwood Flux Thimble Tube Inspection Program.

MR. BASHOR: Thank you, Albert. This item of interest comes from the difficulties Braidwood has experienced in obtaining any current data on the flux thimble tubes during planned evolutions in recent refueling outages. The NRC reviewed this operating experience during the September 2014 Region III inspection at Braidwood and captured it as an item of interest. This issue was only applicable to Braidwood since Byron has not experienced similar difficulties in obtaining any current test data.

Before I begin discussing the issue, I will first present a description of the flux thimble tube arrangement. Slide 22 please.

The flux thimble tubes are part of the in-core flux monitoring system and provide a dry tube which allows a movable in-core neutron detector to be periodically inserted into the reactor core without directly exposing the detector to reactor coolant environment. The retractable flux thimble tube is inserted into the reactor core through the seal table, the guide tube, the reactor vessel penetration, the lower reactor vessel internals and into a designated fuel bundle. A high pressure seal provides the pressure boundary between the flux thimble tube and the seal table.

The flux thimble tube is a semi-flexible, stainless steel tube sealed on one end and with an outside diameter of 0.3 inch and an inside diameter of 0.2 inch. The length of the flux thimble tube can vary between approximately 109 feet to 125 feet depending on core location.

There are 58 flux thimble tube core locations. The flux thimble tubes establish part of the reactor coolant boundary and are classified as instrumentation for the ASME Code. Slide 23.

Recently, Braidwood has experienced difficulties in obtaining flux thimble tube eddy current test data due to increased resistance or restriction when inserting the eddy current probes. This issue has been entered into the corrective action program for resolution.

To this issue, a team has been established to determine the cause of the issue and has developed actions to prevent future recurrence. Possible causes include presence of moisture in the tube from the cleaning process, changes to the current eddy test equipment or deformation or blockage of the tube.

To resolve the potential for residual moisture in the flux thimble tubes, the need for tube cleaning prior to eddy current testing will be evaluated. The current testing practice includes flux thimble tube cleaning, but this process may provide a source of moisture that may in turn lead to hydraulic block when attempting to insert the eddy current probe.

Industry peers with similar designs have been benchmarked. And it has been determined that cleaning may be unnecessary. A mock-up will be created using a spare flux thimble tube to simulate the as-installed configuration. Testing of the mock-up will then be performed to determine the cause of the restriction or to identify if there is an issue with the eddy current probe being able to pass through the tube.

Also a controlled extraction of a flux thimble tube would be performed if future eddy current testing attempts are unsuccessful. The removed flux thimble tube will then be examined to identify the cause of the restriction. In addition to determining the cause of this issue, the use of improved eddy current testing equipment has been pursued.

One improvement in the testing equipment is to use a more rigid drive cable to insert the eddy current probe into the flux thimble tube. Based on the current process, a dummy probe is fully inserted into the flux thimble tubes after cleaning but before eddy current testing. The dummy probe has the same outside diameter as the eddy current probe, but it=s driven into the flux thimble tube utilizing the more rigid drive cable.

This dummy probe has been successful when inserted into the flux thimble tubes in recent outages. Therefore, a more rigid drive cable from the current eddy probe may allow for full insertion of the probes.

Second improvement to the testing equipment is to use a smaller eddy current probe. An eddy current probe with a smaller outside diameter rather than the current 0.188 inch is being evaluated. The smaller eddy current probe will be tested in a spare flux thimble tube to verify that this approach will be effective.

The final contingency corrective action is to evaluate replacing the flux thimble tubes at the larger diameter tube. A flux thimble tube with a larger diameter tube would provide additional clearance. Slide 24 please.

Eddy current testing to monitor for wear of the flux thimble tubes has been performed since 1989 when the program was implemented at Braidwood. The frequency of the eddy current testing is based on plant-specific testing data and is set such that no flux thimble tube is predicted to incur wear that exceeds the acceptance criteria before this next scheduled test.

Conservative projections of future wear are performed to determine if the flux thimble tubes remain satisfactory for continued service. This methodology is in accordance with the NRC Bulletin 88-09 and is consistent with the WCAP-12866 and the GALL report.

Although recent test data has not been obtained, sufficient data exists to project future wear until the next tests which are scheduled for the spring 2015 refueling outage for Unit 1 and the fall 2015 refueling outage for Unit 2. If flux thimble tube cannot be tested and cannot be shown by analysis to be satisfactory for continued service, then the tube is conservatively removed from service by either capping or replacing the tube. This approach is consistent with the GALL report for flux thimble tubes where eddy current testing data is not obtained.

During the most recent refueling outages, two Unit 1 flux thimble tubes were conservatively capped and five Unit 2 flux thimble tubes were conservatively replaced because eddy current testing data was not obtained and projected wall loss was not satisfactory for continued service until the next scheduled test.

For the remaining in-service flux thimble tubes, the highest projected wall loss due to wear for each unit at the next scheduled test is less than 60 percent. The WCAP-12866 determined that flux thimble tubes remain functional with up to 85 percent wall loss. And since no tubes are projected to have a wall loss greater than 60 percent, adequate margin exists to ensure flux thimble tube integrity is maintained until the next scheduled test.

This issue has not affected the performance of core flux mapping. In order to provide more assurance that the program will remain effective, Exelon has added a commitment to replace flux thimble tubes if the eddy current testing data is not obtained as required. The slide summarizes this replacement commitment. Slide 25 please.

MEMBER RICCARDELLA: Excuse me before you get off this slide. So when you say on Unit 2 seven completed, those aren=t seven exams. Those are seven replacements.

MR. GALLAGHER: Yes, that=s the replacements. That=s correct, replacements.

MEMBER RICCARDELLA: When you do replace them, do you look at the old ones that you took out to see if there=s been wear, see how much wear there=s been? Do you do destructive analysis?

MR. GALLAGHER: Yes, Dr. Riccardella.

MEMBER RICCARDELLA: John.

MR. BASHOR: I will tell you it=s a very difficult process because you pull that section of the tube out. You clip it off. You pull a section of tube out. Clip it off. Very highly irradiated material typically put in a bucket.

So you know one of the things we will be doing going forward is if we find ourselves in a situation where we have to do a destructive examination is figuring out how we will label each piece of tube so that we know exactly what location in the dry tube was located.

MEMBER RICCARDELLA: But the primary plan is to get to the point where you can do the eddy test.

MR. BASHOR: That=s correct.

MEMBER RICCARDELLA: Understand.

MR. BASHOR: Okay. Slide 25. In conclusion, the current implementation of the flux thimble tube inspection program will ensure the integrity of all in-service flux thimble tubes until the next scheduled test. In order to provide more assurance that the program will remain effective, Exelon has added a commitment to replace flux thimble tubes if the required eddy current testing data is not obtained.

Corrective actions have been identified and are in progress to resolve this issue. Additional information on this item of interest has been provided to the NRC staff and letters submitted on October 31, 2014 and November 22, 2014.

I will now turn the presentation over.

CHAIRMAN SKILLMAN: John, let me ask a question. What role does the flux mapping or the thermal couple play in your accident response procedures? Is there any role whatever from the information from the problems that are in the thimbles?

MR. GALLAGHER: Craig, could you answer that? Did you hear the question?

CHAIRMAN SKILLMAN: What=s the role of this in accident management?

MR. INGOLD: My name is Craig Ingold. I=m a former shift manager and senior reactor operator at Braidwood. There is no role for import thimble flux mapping in post-accident response.

CHAIRMAN SKILLMAN: Did you look at the

thermal couples that in here, in the system, for any?

MR. INGOLD: For core exit, we used core exit thermal couples. We don=t use the in-core system for any exit response.

CHAIRMAN SKILLMAN: Okay. Thank you.

MEMBER STETKAR: Before you switch gears, John, I have a couple of questions. This is also Braidwood 2. The operating experience shows that you=ve had some unexpected wear rates on a couple of flux thimbles. One was a new one that was installed in I think the fall of -- I=m reading notes here. So bear with me -- 2009. And the first inspection showed a 35 percent wear that increased to 41 percent in 2002 which is kind of an unexpected wear rate.

The other one was an original flux thimble that had apparently 36 percent wear in 2008 and it increased to 57 percent in 2011 which seemed a rather dramatic increase in the wear rate compared to the previous ones. I=m assuming you inspected those in both the fall and the spring 2014 outages. What were the observed wear on those two outages, the most two recent inspections?

CHAIRMAN SKILLMAN: Gary or John.

PARTICIPANT: Give me a minute. I have

to look up that.

CHAIRMAN SKILLMAN: Okay. You can look it up. You also said the exact cause of the higher anticipated wear rates has not been determined. Do you have any guess of why they=re wearing like that?

MR. BECKNELL: Gary Becknell, License Renewal Project Team. The flux thimble tube inspection program is for monitoring of wear due to flow induced vibration. And flow induced vibration is a specific aging mechanism which provides a more predictable wear rate.

Wear can also be caused by other event-driven type issues such as foreign material or improper installation or maintenance activities. So without doing a post mortem of the tube, the actual cause of the increased wear has not been determined.

MEMBER STETKAR: I can understand perhaps installation on the new one. Actually, I=m a little more curious about why the original one suddenly showed an increase which could be foreign material.

MR. BECKNELL: Right. That=s sort of where we=re speculating. Now with the recently installed one what we saw was it was installed and ran for I believe it was one cycle. Then we measured it which you expect to see a lot of wear during the first cycle.

MEMBER STETKAR: You expect to see, yes, some wear.

MR. BECKNELL: Well, the highest wear rate would happen in the first cycle as it sort of wears itself in.

MEMBER STETKAR: Right.

MR. BECKNELL: Whereas in the past when we would install a new one, we wouldn=t necessarily inspect it for maybe a couple of cycles.

MEMBER STETKAR: Okay.

MR. BECKNELL: Spread it out over two or three cycles to wear rate might tie in.

MEMBER STETKAR: Yes. So the average wear rate.

MR. GALLAGHER: So the staff in the application and in the SER they use our words that come from the corrective action. And the corrective action reports were written as higher than expected wear.

MEMBER STETKAR: Sure.

MR. GALLAGHER: When you really look at it, for a first cycle operations, it=s really not higher than expected.

MEMBER STETKAR: I may give you that on the first one.

MEMBER STETKAR: The one you=re talking about.

MEMBER STETKAR: The original one I=m curious about. And also if you can find the results, I=m just curious. Apparently, they weren=t replaced because you would have said immediately AOh we replaced those, too.@

MR. GALLAGHER: Yeah. Which unit was that on?

MEMBER STETKAR: Braidwood Unit 2. If you don=t have it readily available you can get back to us.

CHAIRMAN SKILLMAN: It gives me some comfortable to watch you scramble through.

MEMBER STETKAR: They=re so smooth doing this. You have to have --

(Simultaneous speaking.)

MR. GALLAGHER: We=ll get you that when we come back from the break.

CHAIRMAN SKILLMAN: That is a drill that we went through on our review trying to figure out which is which here. I understand you=re going to come back with that.

MR. GALLAGHER: Yes, we can get them that specifically.

CHAIRMAN SKILLMAN: Then let=s proceed and when that information is available we=ll speak about it then. Thank you.

MR. GALLAGHER: Okay. With that point, we=ve finished the discussion on the flux thimbles and just turning it back to me to conclude.

CHAIRMAN SKILLMAN: Before we conclude, let=s -- John and I had some questions.

(Simultaneous speaking.)

MR. GALLAGHER: And that=s just where we are. We=ve finished our presentation. And are there any other questions you have?

CONSULTANT BARTON: My questions have to do with tanks onsite. We=ve had some experience where we=ve seen that tanks have not been inspected but promised to do one before I go into operation and we=ve seen some where we experienced some leakage. And I looked at your tanks and I don=t have a feel for how you inspect them or when you inspect them. The refueling water storage tank, the description is a stainless steel liner within a reinforced concrete enclosure.

Now does that have some kind of an inspection program? How do you inspect it? It just seems like a configuration that=s looking for a way to get looked at.

MR. GALLAGHER: Why don=t Jim or Ed answer that question? Jim.

MR. ANNETT: My name is Jim Annett. I=m on the License Renewal Project Team. The fuel storage tank is a concrete tank with a stainless steel liner. So it=s more than just being inside a concrete enclosure.

CONSULTANT BARTON: Is there any inspection program for that? Have you inspected it since initial operation?

MR. ANNETT: The aging management for the liner is we use the water chemistry program. So this is similar as what is done for the spent fuel pool and the configuration for the liner uses the same details as we use for the spent fuel pool.

MR. GALLAGHER: So there isn=t an inspection per se.

CONSULTANT BARTON: Is the old fall-back. I=m going to use the chemistry.

MR. GALLAGHER: The water chemistry and we maintain the water chemistry.

CONSULTANT BARTON: Okay. Your condensate storage tanks are similar to some other sites where they=re resting on a concrete doughnut that=s filled with compacted sand. And we have seen some experience where tanks with this configuration have developed leaks. I wonder what your experience is.

Do you have an inspection program for them? And has it found any thinning of the tank bottoms if that=s what you=re doing? Have you done any UTs on the tank bottoms on those tanks?

MR. GALLAGHER: Maybe we can ask Paul Weyhmuller to answer that question. Paul.

MR. WEYHMULLER: Paul Weyhmuller, Exelon License Renewal Team. The tanks, the CSTs, both at Byron and Braidwood are constructed of aluminum. And as of this time, they have not been inspected, the bottoms, through a UT process.

CONSULTANT BARTON: Well, there has been some experience with tanks in this configuration that have thin bottoms. So my concern would be if you haven=t looked at it since initial plant operation, maybe it=s due for inspection.

MR. WEYHMULLER: Braidwood Station actually raised the walls of their tanks and with that they removed a new section of the tank bottom on the perimeter where the wall came down on top of it. And at that time the inspections did not find any issues with wall loss. That=s the information we have so far on tank bottoms for CST.

CONSULTANT BARTON: Is there any plan to do inspections of the tank bottoms between now and extended operation?

CONSULTANT BARTON: The above ground tank program is a new program. The tank bottoms will be inspected five years prior to PEO which will include ultrasonic examination as well as because of water chemistry. There=s one time inspection program. We will also perform the internal visual inspections at that time as part of that program.

CONSULTANT BARTON: Okay. Thank you.

MEMBER STETKAR: You=re going through another tank or something else, John.

CONSULTANT BARTON: Diesel oil storage tanks.

MEMBER STETKAR: Let me follow up on the CSTs.

CONSULTANT BARTON: Okay. This is the insulation problem.

MEMBER STETKAR: Yes. You=re going to do it?

CONSULTANT BARTON: Yes. I=ll finish up on that.

MEMBER STETKAR: Okay, you can do it.

CONSULTANT BARTON: The NRC reported I think in an inspection report that the insulation on the CST had slipped down. So part of the tanks are exposed. In addition, Braidwood Unit 2 CST above the water line has an indication. Has it been looked at? Evaluated engineering wise? It=s an indication there=s a detection in the tank wall. What have you done about the insulation that has slipped down on those tanks?

MR. GALLAGHER: Okay. I think we need Paul again to help.

MEMBER STETKAR: I was hoping he wouldn=t sit down.

MR. WEYHMULLER: Paul Weyhmuller, Exelon License Renewal Team. So the first question on the insulation that is from Byron Station. Both Units 1 and 2, the insulation has moved down approximately one and a half inches on Unit 2 and slightly less on Unit 1. It=s in the planning process now to restore that area so that the insulation does go all the way back up to the roof.

It is thought it=s due to the stainless steel banding clamps that go around the circumference of the tank that hold the lagging in place. There is some looseness in some of the straps which allow it to slide down that distance.

CONSULTANT BARTON: Well since the insulation has dropped, there has been exposure to the environment. And you can get water down between the tank itself and the insulation since the tank is not completely covered.

MR. WEYHMULLER: The tank group overhangs the side wall of several inches, but with blowing rain there could be that possibility. When it was being reviewed as far as the issue from the access ladder a visual observation was made of the tank wall in that area. In comparing it to the tank roof, the tank roof is made of the same material, aluminum, and it is not insulated or coated in any way. And the surface condition was found to be similar to that of the --

CONSULTANT BARTON: I=m worried about

water trapped between the insulation and tank. Since you had a gap, you could get rain sometimes coming in parallel. You could get water on the tank surface down between that and the insulation. And that=s what I=m concerned about. What about the tank surface below inside the insulation below?

MR. WEYHMULLER: Our aging management program will remove insulation in 25 different areas, one square foot areas. In particular, we have committed to do at least four areas where there have been penetrations of possibility of water intrusion to inspect that area both visually and with a exam for cracking.

CONSULTANT BARTON: Has that been done yet or is that down in the future sometime?

MR. WEYHMULLER: That is out in the future at this time.

CONSULTANT BARTON: So you don=t really know what the condition is right now of those tanks.

MR. WEYHMULLER: The roof of the tank itself is exposed to the weather. So we can see that as well as the inner welds.

CONSULTANT BARTON: That=s different. The roof is exposed to the environment. How about what=s trapped between the insulation and the tank wall is what I=m concerned about.

MR. WEYHMULLER: There=s not been any examinations under the insulation at this time. The tank material though is --

CONSULTANT BARTON: Aluminum, right?

MR. WEYHMULLER: Yes. That is correct. And it is of a grade that is not susceptible to cracking. We have committed to do the inspection for cracking as part of our aging management program.

CHAIRMAN SKILLMAN: What is the chemistry of the insulation? What=s the insulation?

MR. WEYHMULLER: That=s why we did make the commitment. The bottom section, the bottom two to four feet, is made of foam glass material. And it was found that it was halide chloride-free. The upper regions of the tank we could not find the paperwork that would satisfy that it was halide or chloride-free.

So therefore we conservatively said there was a possibility it could contain one or more of those materials. And therefore we put in that we would inspect for cracking on the tank walls.

MEMBER BALLINGER: How tight is the insulation?

MR. WEYHMULLER: How tight is it?

MEMBER BALLINGER: Yes.

MR. WEYHMULLER: It has a corrugated lagging cover and then stainless steel banding straps.

MEMBER BALLINGER: On the interface between the aluminum and the insulation, how tight is that?

MR. WEYHMULLER: It=s pulled up tight to the tank.

MEMBER BALLINGER: So it=s real good crevice.

MR. WEYHMULLER: Yes.

MEMBER BALLINGER: That=s the good news. That=s also the bad news.

CHAIRMAN SKILLMAN: It=s a 34 inch belt loop for a size 36 pants.

MEMBER BALLINGER: I=ve been inspecting it for pitting and other kinds of things.

MR. WEYHMULLER: Right.

MEMBER BALLINGER: And I don=t know what the aluminum alloy is. Does anybody know the designation?

MR. WEYHMULLER: I can find that. I have that.

MEMBER BALLINGER: Because some of these materials are --

MR. WEYHMULLER: Very susceptible.

MEMBER BALLINGER: And chloride can come from just about anywhere.

MR. GALLAGHER: But I think as Paul indicated we do have it in our corrective action program.

CONSULTANT BARTON: You haven=t looked at this. So there=s a possibility it could have something going on with the aluminum.

MEMBER BALLINGER: It=s a lot easier to see pitting and stuff like that than it is to see cracking.

CONSULTANT BARTON: Right. I guess our concern is are you going to --

MEMBER POWERS: Depends on the crack.

MR. GALLAGHER: Yes. The assessment was done at the top of the tank and our aging management will address the full tank. So that=s a challenge to say should we be looking at this sooner than later.

MEMBER POWERS: Exactly.

MR. GALLAGHER: And we=ll take that challenge.

MEMBER BALLINGER: Okay.

MEMBER STETKAR: Don=t sit down. I=m not done.

MEMBER BALLINGER: Is the inspection going to be from the inside of the outside?

MR. WEYHMULLER: The inspection is done from the outside of the tank. We have to remove the lagging and insulation.

MEMBER BALLINGER: You have to remove the lagging.

MR. WEYHMULLER: Yes, that=s correct.

MEMBER STETKAR: A couple of questions. One is just for clarification because I=m not capable of reading everything that=s sent to us. I did find something that was quoted in the SER as part of a response to an RAI. So I have to qualify it that way. It=s perhaps thirdhand information.

You mentioned inspection of 25 locations being in at least what I read said 25 locations for both tanks combined per site which could mean 12 on one and 13 on another. Are you actually going to inspect 25 locations on each tank?

MR. WEYHMULLER: No, the inspection programs, because the tanks are right next to one another, you would take one of the tanks for each evolution.

MEMBER STETKAR: But we=ve already now confirmed that they=re not identical because they had different wetting histories. And indeed the license renewal guidance, I was going to ask the staff about this because they accepted it.

But the guidance says each tank. It doesn=t say tanks that are close to one another and mostly the same. But you do clarify that it=s not 25 per tank. So we=ll ask the staff about that.

The other question I had is you discovered this slipped down insulation in August of 2012 and you said you=re still planning on how to repair it. Why does it take more than two and a half years to figure out how to repair this? And don=t tell me you have to do it during an outage because I can stand there and look at the outside of the tank. So why is it taking and why are you still planning this?

MR. GALLAGHER: Yes. I think our assessment was that because the configuration we have on the bottom insulation and the inspections that were done where the gap is and the overhang and the condition of the roof that it=s no significant degradation going on at this point. And we just have to --

CONSULTANT BARTON: So it has low priority in your corrective action system.

MR. GALLAGHER: Well, it=s a activity that we have to prioritize with all the other activities that we have. And we do have it in our aging management program that will be done on an ongoing basis.

MEMBER STETKAR: Yes, but that=s in like 2026.

MR. GALLAGHER: Well, the five years before PEO.

MEMBER STETKAR: I mean 2021.

CHAIRMAN SKILLMAN: I guess I=m surprised that A&I and the boiler machinery inspection hasn=t forced this a long, long time ago. I can recall being forced to do tank bottom inspections much against my will. You=ve got a submarine and you=re going to look at tanks.

But it was really A&I and the boiler machinery inspection portion of our insurance policy that forced us to do that. These are big machines with real consequences. I=m surprised that that hasn=t been an action item for the site based on your A&I policy.

MR. GALLAGHER: For the safety tank

bottoms, yes.

CHAIRMAN SKILLMAN: Yes. But hey. I=ll leave that as it is. John or other John, Chairman, any further questions?

MEMBER STETKAR: No, no, I=m done on the CSDs. We=ll give it back to John.

CONSULTANT BARTON: The only other thing I had the same question on diesel oil storage tank, the 50,000 gallon tanks that are in the auxiliary building. Is there some kind of inspection program for them? Are they freestanding? Are they buried in concrete in the auxiliary building? I mean, what=s the configuration of them and have they been looked at?

MR. GALLAGHER: Paul.

MR. WEYHMULLER: Paul Weyhmuller, License Renewal. There=s two 25,000 gallon tanks on Unit 1 and a 50 on Unit 2 for both stations. They=re freestanding tanks sitting on a concrete pedestal or slab. They are inspected on a 10 year frequency. They=re drained, cleaned and then a visual inspection is performed. So they have been inspected.

CONSULTANT BARTON: Thank you.

CHAIRMAN SKILLMAN: John.

CONSULTANT BARTON: I=ve got some other items.

CHAIRMAN SKILLMAN: When you=re done I=ve got a couple more. We=ve got a few more minutes.

CONSULTANT BARTON: All right. Other than Braidwood essential service cooling pump, I couldn=t find any reference to looking at the retaining dike. Did it ever get looked at because of the materials of the dike around the pond? Is it ever inspected? Have you looked for degradation of the materials that make up that dike?

MR. GALLAGHER: This is the dike around the whole pond.

CONSULTANT BARTON: Around the whole pond. Is that ever looked at?

MR. GALLAGHER: Paul Cervenica.

MR. CERVENICA: My name is Paul Cervenica. I=m a member of the License Renewal Team. The dike surrounding the pond is inspected every three months by the site and they look for general condition degradation. And on a 12th month basis, a professional engineer comes in and does a survey and reports on the condition.

CONSULTANT BARTON: Thank you, Paul. Now

the essential service cooling pond has a triangular excavated area within the cooling pond itself. And it=s the ultimate heat sink for the plant. Is it ever looked at? Does anybody ever go down and look at the structure of it?

MR. GALLAGHER: I think that=s Paul again on that one.

MR. CERVENICA: Paul Cervenica, member of the License Renewal Team. There are soundings done on the essential service water cooling pond. Soundings at the bottom and the slope walls in order to confirm that the volume required by tech specs is maintained. That=s done every 18 months.

CONSULTANT BARTON: Thank you, Paul.

The next area that is cathodic protection. It was noted that the system has improved, but there=s less than 50 percent of the site adequately protected. And experience has shown that at both sites corrosion has occurred due to the lack of protective coating. I think you people said that you=re going to improve the cathodic protection system. Is that now complete? Is it functioning? And how effective is it?

MR. GALLAGHER: Dylan.

MR. CIMOCK: Dylan Cimock, License Renewal

Team. The cathodic protection system is improving and plans are in place that includes investigation of means by which to improve it which includes replacement of existing anodes and insulation of new anode beds. The configuration of how to do that and the exact means is still being investigated. But that is our intent. It=s to improve the overall coverage cathodic protection of the station.

CONSULTANT BARTON: Since you don=t have a lot of piping covered by it, what=s your schedule to complete it and get a system operating so you can assess the effectiveness of it?

MR. CIMOCK: The intent would be to complete that hopefully five years prior to the period of extended operation which would be consistent with allowances provided in the ISG.

CONSULTANT BARTON: In the meantime, do you do any piping inspections that=s not covered?

MR. CIMOCK: Yes, significant piping inspection have been performed. And while it might be characterized as not protected, it does receive some protection. It just may not be meeting established acceptance criteria. That criteria is applied universally to all piping.

MEMBER BALLINGER: That=s the minus 830.

MR. CIMOCK: Eight fifty, correct.

MEMBER BALLINGER: Eight fifty.

MR. CIMOCK: Right. So it is possible to achieve adequate protection without that negative 850. So that is something that is being investigated as well. While we had seen some degradations, it has been quite minor I would characterize it as.

CONSULTANT BARTON: How do you do it? When you=re doing some maintenance and you=re digging a hole and you look at the piping? Or is there anything planned to go and look at specific areas of the piping in the plant?

MR. CIMOCK: Yes. Both stations are implementing the NEI 09-14 initiative on buried piping. So they have strengthened their piping. Excavated significant portions, approximately like 300 feet for example of condensate piping at the Braidwood Station has been excavated. Approximately 300 feet at Bryon Station for service water.

CONSULTANT BARTON: How aggressive is the soil at the site?

MR. CIMOCK: Not very aggressive from the soil samples that have been taken.

MEMBER BALLINGER: Can you interrogate your cathodic protective system? I presume that most of the piping is coated.

MR. CIMOCK: That=s correct.

MR. JOHNSON: And so can you interrogate your protective system based on the current that=s being supplied to identify potential sources where you think you=re providing protection and it=s not working anymore?

MR. CIMOCK: Yes, we do maintenance and surveillance on rectifier availability so we can identify where rectifiers are out of service and not providing adequate protection. But the stations have also done alternative cathodic protection assessments. It=s called an APEC survey, aerial potential earth current.

MEMBER BALLINGER: Yes.

MR. CIMOCK: And that has shown there are areas that I guess are more or better protected than others.

MEMBER BALLINGER: So you can rank order. You have rank ordered systems in terms of susceptibility which then allows you to establish what to do next.

MR. CIMOCK: Yes.

CONSULTANT BARTON: You=ve got some unprotected carbon steel piping embedded in concrete at the service water structure. Now do you ever go look at the piping internally? I know you can=t look at it externally because it=s in concrete. Do you ever go look inside and see if there=s anything going on in that piping?

MR. GALLAGHER: Dylan.

MR. CIMOCK: Dylan Cimock, License Renewal Team. Piping is not inspected internally and as you point out it can=t be gotten to externally as well. They do other surveillances because it=s safety-related piping like flow and pressure tests on the piping.

And any leaks that would arise you would see based on the pressure of the system. And that=s not been seen either. And flow rates have been adequate. They have done external excavations of that reinforced concrete section. You can=t get to the pipe, but you can inspect its backfill. And they inspected that and found that to be fine as well.

MEMBER BALLINGER: But again that pipe is also wrapped.

CONSULTANT BARTON: No, it=s in concrete.

It=s unwrapped carbon steel pipe inside concrete.

CHAIRMAN SKILLMAN: Inside pipe. It=s embedded piping.

CONSULTANT BARTON: Embedded piping in concrete. And how do you know what=s going on inside that piping?

MEMBER STETKAR: Part of it below groundwater level.

CONSULTANT BARTON: Pardon?

MEMBER STETKAR: Part of it below groundwater level.

CONSULTANT BARTON: Right.

MEMBER BALLINGER: Well, you could pig it to see it effectively.

MR. CIMOCK: That=s been investigated. Right now, they=re trying to find means by which to do because it=s a very long length of piping with obstructions along the way that would prevent that. So it is being investigated as part of their NEI initiative and they=re trying to find a way of doing that under the mitigative actions performed in that piping.

CONSULTANT BARTON: I=ve got one other one here. The inaccessible power cables not subject to

50.59 environmental qualification. At Byron Unit 2 based on the site history, especially cable bolt OB 2 at Byron Station. What is the status of work that was planned to limit surface water intrusion into that wall?

MR. GALLAGHER: John Hilditch.

MR. HILDITCH: John Hilditch, License Renewal Project. That particular wall had water intrusion from a hand hole. That hand hole was modified back in July to make it more water resistant. The ground was graded. So the water wouldn=t flow on top of there. And there=s been some significant rain storms since. And the water intrusion problem is no longer there.

CONSULTANT BARTON: How do you know? Do you now periodically inspect?

MR. HILDITCH: Yes.

CONSULTANT BARTON: Okay.

MR. HILDITCH: And the scoping is inspected periodically.

CONSULTANT BARTON: I think that=s it.

CHAIRMAN SKILLMAN: Thank you, John. I=d like to ask a few more questions. I realize we=re over our break time. But I think when I=m completed we=ll be done with this portion of the session.

Bolting integrity program, it=s B.2.1.9. There are three enhancements on Byron and two enhancements on Braidwood. And I=m wondering why there is a difference in enhancements for bolting integrity between the two stations please.

MR. TAMBURRO: Pete Tamburro, License Renewal Team. The difference in enhancements is because some of the submerged bolting that are required to be -- that will be inspected there were no existing activities to inspect them. So we had to initiate existing activities to inspect those submerged boltings at Braidwood.

CHAIRMAN SKILLMAN: Thank you, Pete. Okay. I=ve got one or two more. This has to do with reactor vessel surveillance and this is at Braidwood. The second enhancement will test on specimen capsule that has been irradiated to a neutron fluence of one to two times the projected peak neutron fluence at the end of the PEO and will submit a summary technical report to the NRC for each reactor vessel within one year of the receipt of the renewed license.

And my question is why does it take the provision of the renewed license to trigger the need for that information in a timely fashion. At least, that=s the way I=m internalizing the way this inspection is written. It seems like we=re really not going to do it until we have the license. And when we have the license only then we=ll go ahead and expose the surveillance specimen to the levels that we need to to predict the 20 year future.

MR. TAMBURRO: On that, Mr. Skillman, we had in our current licensing basis, the 40 year license life, done all the testing necessary for it.

CHAIRMAN SKILLMAN: The 40 year license.

MR. TAMBURRO: Yes. And those specimens actually for each unit, for each of the four units, were exposed to the one to two times the exposure levels and were removed and are currently sitting in the spent fuel pool at the four stations.

We thought when we put our application in that we would then just need to test them before we entered the period of extended operation. The staff pointed out to us that it could be interpreted that in the Appendix H provisions. Once you get a renewed license those specimens would be required specimens.

They weren=t required specimens in your current licensing basis. But once you get the renewed license they are.

MR. GALLAGHER: And then you=re on the one year time clock unless you get a schedule change from the director of NRR. We took a look -- We didn=t view it that way when we put the application in. We took a look at the staff=s position and agreed with them that that was correct. So we made that commitment. So it was very clear that we would follow Appendix H and get those testing done within a year of getting the license.

Now we=re not waiting for that obviously because these tests take some time. And we actually have a contract already cut and it=s to Westinghouse. Those activities are going to start beginning of next year 2015. And throughout 2015, those four samples would be tested.

We don=t anticipate getting our license until the end of 2015. So we would be well completed before it=s needed.

CHAIRMAN SKILLMAN: Thank you, Mike. That concludes my questions. Let me --

MR. GALLAGHER: I think we have the answer to Mr. Stetkar=s question on the wear.

CHAIRMAN SKILLMAN: Okay.

MEMBER STETKAR: I knew we could drag it on long enough for you to find it.

MR. MATTHEWS: Sorry. John Matthews, Braidwood Station Plant Engineering. So the question was in Unit 2 there was an original thimble that had higher than expected wear rates that showed up. And the question was what happened subsequent to that inspection.

The following inspections showed that cycle to cycle wear had gone back to its normal rate at three percent. However, that was capped out and replaced at later outages.

MEMBER STETKAR: Okay. So that one=s been capped and replaced. How about the new one?

MR. MATTHEWS: The new one, subsequent eddy current testing showed that the wear rate had stabilized.

MEMBER STETKAR: Wear rate is stabilized. Thank you.

CHAIRMAN SKILLMAN: Okay. For this portion of the meeting, let me check with my colleagues. Dr. Riccardella, any further comments?

MEMBER RICCARDELLA: No further comments. Excellent presentation.

CHAIRMAN SKILLMAN: Okay. Dr. Ray? Dr. Powers? John Stetkar? John?

MEMBER STETKAR: Nothing.

CHAIRMAN SKILLMAN: With that, I=m going to claim a 14 minute break. Please return at 10:30 a.m. on that clock. Off the record.

(Whereupon, the above-entitled matter went off the record at 10:17 a.m. and resumed at 10:31 a.m.)

CHAIRMAN SKILLMAN: On the record. Ladies and gentlemen, we=re back in session. And for this portion of the meeting, I=m going to call on Lindsay Robinson, our project manager. Lindsay.

NRC STAFF PRESENTATION SER OVERVIEW

MS. ROBINSON: Great. Thank you, Chairman. Committee Chairman, Members of the ACRS, my name is Lindsay Robinson. I=m the Project Manager for the License Renewal of Byron Station Units 1 and 2 and Braidwood Station Units 1 and 2.

Before I get started, I=d like to introduce the people at my right and left. Nestor Feliz-Adorno, he was the lead for the Braidwood 71002 inspection. He=s a Region III Senior Reactor Inspector. I have Mel Holmberg. He was the lead for the Byron 71002 inspection. He is also a Region III Senior Reactor

Inspector.

He had Dr. Allen Kiser. He is DLR=s Senior Technical Advisor. And then we have Daneira Melendez. She=s a Project Manager. She will be assisting me with the slides today.

We=re here today to discuss the review of the Byron and Braidwood License Renewal Application as documented in a safety evaluation report with open items which was issued on October 30, 2014. Seated in the audience are members of the technical staff who participated in the review of the license renewal application and conducted the onsite audits. Next slide.

We=ll begin the presentation with the general overview of the staff=s review. Next, Mel and Nestor will both present the activities and inspection observations from the 71002 inspections for Byron Station and Braidwood Station.

We will also discuss some issues that arose during the 71002 inspection that are not reflected in the SER open items. These issues and their resolutions will both be documented in the final SER.

We will then present the main sections of the SER and any associated item. Next slide.

The Byron-Braidwood License Renewal Application is a dual site application consisting of four reactors in two geographical locations. Considering the scope of the review, the staff found very few technical differences between the two sites. And where those differences did occur in either the site and/or unit the staff made a point to clearly identify where those applicable differences were per that site and/or unit.

The staff did conduct several onsite audits and inspections at each site. During the scoping and screening methodology audit, the audit team reviewed the Applicant=s administrative controls governing the scoping and screening methodology and the technical basis for selected scoping and screening results.

The staff also reviewed selected examples of component material and environmental combinations, reviewed information contained in the Applicant=s corrective action program relevant to plant-specific, age-related degradation and reviewed quality practices applied during development of the LRA and the training of personnel who participated in the development of the LRA. There was also the audit where it documented in a report dated March 14, 2014.

During the aging management program audit, the audit team examined the Applicant=s aging management programs and related documentation to verify that the Applicant=s claims of consistency with the corresponding AMP in the GALL report. The staff reviewed 45 aging management programs and documented the results in a report dated March 13, 2014.

Mel and Nestor will discuss the activities of the 71002 inspection in a few minutes. Next slide.

In addition to the audits and inspections already mentioned, the staff conducted in-depth technical reviews and issued requests for additional information or RAIs. The staff performed its review of the Byron and Braidwood license renewal application and issued the safety evaluation report with open items on October 30, 2014. Pending the resolution of the open items and outstanding RAIs, our plan is to issue the Bryon and Braidwood final SER in April of 2015.

We will now direct the presentation to Mel and Nestor to discuss the Region III 71002 inspection. Next slide.

MR. HOLMBERG: Thank you, Lindsay. Good morning. My name is Mel Holmberg. I=m a Senior Inspector in the Division of Reactor Safety in our

Region III office. That=s in Lisle, Illinois. And I was also the lead for the Byron inspection.

MR. FELIZ-ADORNO: Good morning. I=m Nestor Feliz-Adorno. I was the Team Leader for the Braidwood inspection.

MR. HOLMBERG: So for the inspections we conducted, this is done under our Inspection Procedure 71002. The purpose is to verify that the Applicant has adequate programs that either planned or in place to implement age management of the structures, systems and components within the scope of the rule. And our inspection is done to confirm that these components will be adequately maintained consistent with existing safety evaluations in the license renewal program.

The specific scope that we conducted at Byron included review of 36 of the 45 age management programs. Twenty-four of these were based on existing programs. Twelve were new. We also looked at four of the five regulated events, four of the non-safety systems that were scoped out of the rule.

Turning to Braidwood, our inspection scope was 31 of the 44 age management programs. Twenty-three of those were existing programs and eight were new. We looked at each of the regulated events of Braidwood and three non-safety systems, structures or components that were scoped out of the rule.

Each of our inspections comprised of two weeks of onsite inspection. And our teams reviewed the site documents related to the regulated events and including at the non-safety related structures or components whose failure could potentially affect safety-related components. And this review was done to confirm the Applicant had applied the required scoping and screening methodology.

At each site, we also completed walkdowns on over two dozen systems, structures or components within the scope of license renewal. And these were done to assess the adequacy of the license renewal boundaries that have been established, evaluate the material condition and conformance with their application and GALL. This activity enabled us to evaluate if the AMPs would be successful in managing the aging effects for systems, structures and components within the scope of the rule.

The inspections are Byron and Braidwood were done in series. This enabled the region to assess each plant individually and then allowed us to increase the number of programs reviewed. And then issues identified at one site were assessed for applicability to the other site. Our final exit meeting was conducted following the end of the second onsite inspection which was Braidwood. Next slide please.

Based on the inspections of the various areas that we were able to observe during our inspection time onsite and these were areas that included both units at each side, we concluded the overall material condition of the structures, systems and components we observed was good.

CONSULTANT BARTON: I=m glad you addressed that. This is the first time I=ve ever had to ask you that question of the 60 something plants I reviewed.

(Laughter.)

CHAIRMAN SKILLMAN: How do you define good please?

(Laughter.)

MR. HOLMBERG: Actually, we do have a way to assess that. During our inspections, issues that are of any type that we can across that looked like conditions adverse to quality, the licensee promptly put into their corrective action program. Issues were considered minor in nature if they didn=t rise to the level of concern that prompted operability evaluations.

And so you=ve got an initial swag on things as to whether or not they=re significant if they don=t prompt some sort of concern for operability right off the bat. So you=ve got a rough guide.

But other than because our focus was on license renewal, we were making sure we were not seeing things that we expected them to pick up in their normal routine programs.

CHAIRMAN SKILLMAN: Thank you. I asked that question because in my experience the turbine building is normally clean and shiny. The radiologically controlled areas are generally clean and shiny. The entrance.

MR. HOLMBERG: The epoxy floor plant and all that.

CHAIRMAN SKILLMAN: Epoxy floor plant, lots of light. A lot of dazzle. But when you take the time to go to the turbine building sump or the auxiliary fuel handling building sumps or the areas that are less traveled, very often you find a very different physical condition, material condition.

CONSULTANT BARTON: Out-buildings is a good example. That is also.

CHAIRMAN SKILLMAN: And so my question is as you get further out into the areas that are not as keenly maintained did you find, if you will, an increasing number of the need for entrances into the corrective action program.

MR. HOLMBERG: The total I believe was a little over a dozen condition reports for Byron. I don=t recall --

MR. FELIZ-ADORNO: Similar for Braidwood.

MR. HOLMBERG: Braidwood. So just to give you a sense of the numbers as to their locations, they varied. I would say your general sense is correct. Obviously, the areas that are easy to travel and well traveled are generally the ones that you expect and do not see the types of issues that you can find in the other areas.

I guess I don=t have a good answer off the cuff for you on that.

CHAIRMAN SKILLMAN: Circ water pump house and the cooling pond pump house would be areas that I would be curious about whether they were clean and neat, whether they were rusting apart or whether they looked like they really looked like they got some preventive maintenance.

MR. HOLMBERG: Yeah, we did have a couple of issues and I=ll have to look up the specific ones I believe from one of those areas. And I can get back to you with the specific item we identified in those areas.

I have five team members working for me. So out of those areas we walked down, I have a lot of other eyes out there. Some of it I don=t have direct observations to rely back to you.

CHAIRMAN SKILLMAN: I don=t need any additional information. You pretty much answered my question. What you=re saying is what is inspected and what is seen on a regular basis is in pretty good shape. As you get further and further away from the main tourist paths, things are not as highly maintained.

MR. HOLMBERG: I would say that=s a correct assessment.

CHAIRMAN SKILLMAN: That=s fair enough. Okay. Thank you.

MR. HOLMBERG: During our inspections, we did identify issues of concern with respect to current and planned programs. These resulted in application changes for some of the AMPs. For example, during our Byron inspection, the team identified some issues that prompted the application revisions to four of the AMPs, including the ASME Section XI, ISI AMP.

For this particular AMP, the Applicant=s description contained in Appendix A -- that=s the UFSAR supplement -- did not include inspections of small bore lines subject to thermal fatigue. And what I=m talking about is the MRP-146 program. That=s an industry program that was not included in their description and is used to manage thermal fatigue.

Additionally, Appendix B did not identify the 10 CFR 55a limitations, modifications and augmentations that go along with Section XI. So that was another issue that was identified for that program.

CONSULTANT BARTON: That protection system aging management program, I don=t know if you look at that. But in reading the AMP, the Applicant=s application for license renewal, I wasn=t thrilled about the extent of that program. Subsequently, I saw that the Applicant submitted a letter that included 14 enhancements to that program.

Is the NRC now satisfied with that program?

MR. HOLMBERG: I think I=m going to turn that to Lindsay. Is this something that was an RAI?

CONSULTANT BARTON: I didn=t mean to catch you off guard.

MR. HOLMBERG: I=m sorry. Was this in response to our inspection?

CONSULTANT BARTON: No, this was the application. I read the aging management program on that system. All right. And I was not too happy that that was an adequate program that was presented. And then I found in further review of the documents produced by NRC that you received a letter on August 2014 that the Applicant had described 14 enhancements to that program. So I guess my question is --

MS. ROBINSON: Mr. Barton, we actually have Bill Holston who can answer.

CONSULTANT BARTON: Are you now satisfied with that AMP?

MR. HOLSTON: Yes. My name is Bill Holston. I=m a Reviewer in the Division of License Renewal. And the aging management program originally submitted was reasonably typical of the plants prior to the issuance of ISG-2012-02. With the issuance of ISG-2012-02, that raised the necessity for a lot of extra enhancements.

Basically what we did was we went into NFPA-25 which is the inspection standard for fire water systems, selected about 16 inspections and tests that we felt were representative of tests and inspections that were revealed, issues of loss material flow blockage. So that=s why the extra enhancements. And we are, yes, at this time satisfied with the enhancements they=ve put in that program.

CONSULTANT BARTON: Thank you.

MEMBER STETKAR: Let me ask. I was going to wait, but since you mentioned an ISG. This is sort of a general question. Anybody up there can field it. I guess I was surprised at the number of RAIs that were issued as a result of the audits and inspections on these units given the time we are into the license renewal process.

This is more recent ones that we=ve seen that have been fairly minor in terms of audit inspection -- I don=t want to call them findings -- RAIs resulting from those activities. And I know this was done under GALL Rev 2, but GALL Rev 2 has been out since 2010 and people knew what was coming well before that. So it can=t be GALL Rev 2.

Is it primarily due to the additional clarifications from interim staff guidance that was issued since GALL Rev 2 in the 2011-2012 time frame? Or do you have any sense of that?

MS. ROBINSON: Sir, I=d just like to get a little more clarification on your question that you=re trying to ask.

MEMBER STETKAR: Okay. What I=m trying to ask is if I look at these audits and inspections compared to other audits and inspections that we=ve seen over the last two or three years for license renewals those other audits and inspections typically identify some issues that are raised in the SER to the level of RAIs, but only a relatively small number. Byron and Braidwood in comparison has quite a large number of them.

And I=m curious why. Is it because the Applicant -- Is it something that the Applicant wasn=t doing or is it something that they didn=t understand in terms of evolving staff guidance?

MS. ROBINSON: So I can actually discuss the portion of actual RAIs following audits and inspections. I can tell you that based on the RAIs --and the Applicant has discussed those issues that came out of the inspection -- I would say yes. That=s not as typical as what we=ve seen in other applications.

I would actually though say that the number of RAIs that came out of the audits -- and we had to do that both at Bryon and at Braidwood -- in terms of that reference we are looking at the two different geographical locations. And to some degree that=s another reason why maybe you might have seen there are more RAIs.

But if we look at it from the perspective of we had to do two audits, one at Byron and one at Braidwood, then we had to do two inspections. And then -- I am acknowledging that, yes, the number of the RAIs in the inspection is not as common.

But I actually was looking at other applications. And the fact that we had four units I actually saw that we were on par, if not slightly less, than some other applications.

MEMBER STETKAR: Okay.

CONSULTANT BARTON: RAIs per unit.

MEMBER STETKAR: RAIs per unit. What was your sense, John?

CONSULTANT BARTON: There=s a lot of them.

MEMBER STETKAR: There are a lot of them and a lot of them were issued -- But a lot of them there was a single RAI that was issued for all units. So if I count RAIs per unit, that=s four.

MS. ROBINSON: I=m not looking at an RAI

per unit perspective because I do agree that the majority of the RAIs that were issued were applicable to all four units. I=m looking at it from the perspective of other audits that have, you know, the AMP audits that occur typically you come out of those AMP audits with 100, slightly more than 100, RAIs.

You look at the number of RAIs that came out of us following the Byron audit which was the first AMP audit that we conducted and we did not have close to 100 RAIs.

MEMBER STETKAR: Well, when you say typically, yes. When I joined the Committee seven years ago, there were a lot issued. But I=m talking about the more recent experience over the past two or three years as things have stabilized quite a bit and as people have become more familiar with the guidance in GALL Rev 2. A lot of the early ones was the guidance, GALL was in the state of transition. So the staff was asking RAIs about kind of looking forward to where Rev 1 was transitioning into Rev 2.

So I used to see a lot related to those types of issues. But GALL has not been stable.

MS. ROBINSON: Right. And I think a lot of the RAIs that we had coming out of the AMP audit were to a large degree clarification RAIs, you know, basing information that was in the LRA.

MEMBER STETKAR: Well, you haven=t answered my question. But thanks.

MS. ROBINSON: Okay.

MEMBER STETKAR: We should go on in terms of getting into the more technical things.

CONSULTANT BARTON: But you=re right. The interim staff guidance has got a bunch of --

MEMBER STETKAR: The interim staff guidance, what I=m trying to push at is are we now in an evolving second range. Five years ago we used to see a lot of RAIs that were kind of hunting for the transition between GALL Rev 1 and GALL Rev 2.

CONSULTANT BARTON: Two, right.

MEMBER STETKAR: My sense quite honestly is now we=re in a range where the licensees are hunting for the transition between GALL Rev 2 and GALL Rev 3 as embodied by evolving interim staff guidance. And I=m trying to get a sense of where the staff is on that.

MS. DIAZ: Yoira Diaz. What is meant by the difference between ISGs and in these is we had several ISGs that evolved from the GALL Rev 2 and were each in between these plans that you=ve seen in the latest. And some of these ISGs that were in the draft form they were finalized by the time that Byron and Braidwood was issued, the LRA was issued. So some of these IRAs could have come from the amount of ISGs that we had as we evolve from Rev 2 and the subsequent guidance that the staff has issued.

MEMBER STETKAR: Thank you. That helps. That at least gets it on the record.

MR. HOLMBERG: Okay. I=m basically almost done with my part. I was in the middle of the second bullet there. We were just finishing up application changes.

CONSULTANT BARTON: All right. Sorry we messed you up.

MR. HOLMBERG: Applicant changes to some of the AMPs that were prompted by inspection. Those have been addressed. The Applicant has submitted changes to the LRA for those.

I=m going to turn it over next to Nestor who will be discussing additional inspection concerns that prompted further staff reviews.

MR. FELIZ-ADORNO: Thank you, Mel. The team identified three issues requiring further NRR review. With the respect to the first item, the team found that the CRDM seismic supports were not included in the scope of the AMP. The Applicant subsequently revised the LRA to include the CRDM seismic support assemblies in scope and included the CRDM support components in the aging management review table 3.5.2 tab 3.

However, during the Headquarters= review, the staff identified concerns with the bolts which Lindsay will discuss later in this presentation. And this issue applies to both Byron and Braidwood.

The second bullet refers to additional inspections of areas of concrete deterioration. Specifically, during the Byron inspection and confirmed during the Braidwood inspection, the inspectors noted the Applicant planned to inspect for concrete deterioration at a distance with the use of a telescope.

The inspection team expressed concern regarding the Applicant=s visual resolution capability to be used during the period of extended operation to quantify degradation based on the quantitative acceptance criteria described in Chapter V of ACI 349.3R. This issue applies to all four units at Braidwood and Byron.

The last bullet pertains to the flux

thimble inspection. During the inspection at Braidwood, the team identified the Braidwood Applicant had not completed the eddy current examinations on any of the 58 tube loops at Braidwood Unit 1 during the September 2013 outage and only complete seven of the 58 flux thimble tubes at Braidwood Unit 2 during the May 2014 outage.

The staff was not aware of the extent of the Applicant=s deficiencies during the review of this AMP. We communicated this to NRR and currently the Applicant=s actions to address this issue are being assessed by the staff. This issue pertains only to the Braidwood Station.

The three examples demonstrate the benefit of the 71002 inspection to verify the programs described by the Applicant in their application recommendation which are consistent with the existing plant programs. It also emphasizes the strong and important coordination between Headquarters and the region in this review process. Next slide please.

In summary, both teams concluded the Applicant performed the scoping and screening in accordance with the rule. Inspectors also found information was easily retrievable and verified the programs were generally effective in managing aging effects.

The teams also verified that Applicant has the tools to track the completion of enhancements and the development of new programs. Lastly, based on the results of these inspections, the inspectors have reasonable assurance that the programs will manage the aging effects and ensure the intended safety functions of SSCs within the rule will be maintained if it is determined that as described in the application with the proposed enhancements and supplemented through the Applicant=s responses to request for additional information and inspection or observations.

Thank you. Now I=ll turn the presentation back to Lindsay.

CHAIRMAN SKILLMAN: Nestor, let me ask you a question please. I=m reading above ground metallic tank program B.2.17 and I find that the Byron and the Braidwood 71002 inspection report-out have identical text. And I=m curious. Is that because this is a new program for each site or is this an administrative cleverness on the part of the inspection team?

MR. FELIZ-ADORNO: It=s a new program. There=s no unique differences between the two sites.

It was inspected by the same inspector. So naturally he will have the same input.

CHAIRMAN SKILLMAN: Identical same input.

MR. FELIZ-ADORNO: Yes.

CHAIRMAN SKILLMAN: Okay. Thank you.

Lindsay.

MS. ROBINSON: All right. We=re on slide 8. Thank you, Mel and Nestor. We will now discuss each of the issues identified during the 71002 inspection.

As previously stated, the Applicant subsequently revised the LRA to include the CRDM seismic support assemblies and scope and included the CRDM support components and AMR table 3.5.2-3. The staff noted that the Applicant=s LRA revision did not state what type of bolts were used for the CRDM seismic supports.

In a letter dated October 9, 2014, the staff issued RAI B.2.1.31 Tab 4, requested information to whether or not high strength bolts in sizes greater than one inch were used in CRDM supports. And, if so, the staff requested the Applicant provide additional information on the type and grade of the material to determine whether the bolts will be managed for cracking due to stress corrosion cracking.

In a letter dated October 16, 2014, the Applicant responded to the staff=s request by stating that there were no high strength bolts in sizes greater than one inch used in the CRDM seismic supports which addressed the staff=s concern. This issue and its closure will be addressed in the final SER and discussed during the full Committee meeting. Next slide.

This next issue involves the Applicant=s procedure to conduct visual inspections of areas of concrete deterioration remotely with the use of an optical aid. The inspection team expressed concern regarding the Applicant=s visual resolution capability to be used during the period of extended operation to quantify degradation based on quantitative acceptance criteria described in Chapter 5 of ACI 349.3R. This issue applies to both Byron and Braidwood Stations, Units 1 and 2.

By letter dated November 6, 2014, the staff issued RAI 3.2.1.30-6 requesting that the Applicant provided information to verify that sufficient visual resolution capability will be used during visual examinations of concrete surfaces of containment structures to detect and quantify forms of degradation for comparison against quantitative acceptance criteria based on Chapter 5 of ACI349.3R.

By letter dated November 21, 2014, the Applicant provided its response to the RAI. The response is currently under staff review. This issue and its closure will be addressed in the final SER and discussed during the full Committee meeting. Next slide.

By letter dated May 19, 2014, the staff issued RAI E.2.1.24-1 requesting additional information regarding higher than expected wear rates in flux thimble tubes at Braidwood Units 1 and 2. In addition, the staff also questioned the adequacy of the program because it was not able to perform examinations on a few of the tubes.

By letter dated June 9, 2014, the Applicant provided a response to the staff=s RAI. In response, the Applicant discussed high wear rate issues and its failure to obtain data on a few tubes based on outage inspections from 2007 to 2012 for both Braidwood Unit 1 and Unit 2. The Applicant also stated that several corrective actions were being implemented to address the issues related to completing eddy current examinations.

One corrective action was to increase the inspection frequency to perform examinations every outage. The staff closed the issue based on the Applicant=s response.

During the NRC 71002 inspection at Braidwood, the staff discovered that the Applicant was not able to complete planned eddy current examinations on any of the 58 tubes at Braidwood Unit 1 during the September 2013 outage and only partially completed seven of 58 flux thimble tubes at Braidwood Unit 2 during the May 2014 inspection.

The GALL AMP for flux thimble tube inspection implements the recommendations of NRC Bulletin 88-09 which established a program to monitor thimble tubes through periodic inspections. The staff was concerned that the program may not be adequate if tube wear examinations are not performed as scheduled and therefore issued an RAI on October 10, 2014.

By letter dated October 31, 2014, the Applicant responded to the staff=s RAI, but did not identify the causes of the problem or provide corrective actions sufficient to address the problem. By letter dated November 22, 2014, the Applicant supplemented its response further by providing additional information and license renewal commitments.

The staff is currently reviewing the Applicant=s supplemental response and the adequacy of the Applicant=s aging management program. This issue will remain open until it=s adequately resolved. This issue and its closure will be addressed in the final SER and discussed at the full Committee meeting. Next slide.

We now shift our focus to the SER. SER Section 2 describes the scoping and screening of structures and components subject to aging management review. The staff reviewed the Applicant=s scoping and screening methodology, procedures, quality controls of the LRA development and training of its project personnel. The staff also reviewed the various summaries of the safety-related systems, structures and components, non-safety systems, structures and components affecting the safety-related components and systems, structures and components relied upon to perform functions in compliance with the Commission=s regulations for fire protection, environmental qualification, station blackout, pressurized thermal shock and anticipated transients without scram.

Based on the review, the results from the scoping and screening audit and additional information provided by the Applicant, the staff concludes that the Applicant=s scoping and screening methodology was consistent with the standard review plan and the requirements of 10 CFR Part 54. Next slide.

SER Section 3 covers the staff=s review of the Applicant=s aging management programs. For a given aging management review, the staff reviewed the item to determine whether it is consistent with the GALL report. Section 3.1 through 3.6 include the aging management review items in each of the general system areas within the scope of license renewal.

If the aging management review was not consistent with the GALL, then the staff conducted a technical review to ensure adequacy. Next slide.

The Applicant submitted 45 aging management programs in the application. What I have before you is actually a table. And what it identifies how it was dispositioned in the LRA. And then the other side actually dispositions how the review identified it in the SER with open items. Next slide.

SER Section 3 contained one open item. Open Item 3.0.3.1.3-1 pertains to wear in the Applicant=s CRDM penetration nozzles. During the AMP audit, the staff noted operating experience which indicated that the Applicant=s CRDM penetration nozzles have wear near the J-groove valve due to interactions with CRDM thermal sleeves centering tabs.

The Applicant has not proposed any examinations to monitor the wear during the period of extended operation but determine continued acceptability of the defect. In response to the staff=s RAIs, the Applicant stated that it is participating in the Westinghouse owner group project which is expected to provide a detailed analysis confirming that the nozzles will continue to perform their intended pressure boundary functions through the end of the renewed license despite the wear.

The Applicant indicated that if the analytical results do not justify continued operation of the nozzles during the period of extended operation or if the staff finds the analysis unacceptable, then the Applicant will provide a commitment to repair or replace the CRDM nozzles that are affected.

MEMBER STETKAR: Lindsay, has that analysis been submitted? It has?

MS. ROBINSON: I=m actually going to cover that right now.

MEMBER STETKAR: Sorry.

MS. ROBINSON: Not a problem. The Applicant provided a brief summary of the results of that analysis on November 24, 2014. The Applicant=s response states that it needs to perform further evaluations to determine if the LRA needs to be revised as a result of the analysis. The staff is currently reviewing the Applicant=s response and also review any additional information which the Applicant provides as a result of the continued evaluation.

In terms of the analysis itself, we have not received the complete analysis from the Applicant. But the Applicant did say that they would be providing that to us.

MEMBER STETKAR: Okay.

MEMBER BALLINGER: But we had a presentation a little while ago that basically discussed the analysis. Am I right?

MEMBER STETKAR: No. Not the analysis.

CHAIRMAN SKILLMAN: Not the analysis. We had presentations discussing what they=re going to do.

MEMBER RICCARDELLA: They said there was a full section to the analysis that justified integrity of the pressure boundary with this wear.

CHAIRMAN SKILLMAN: Yes, Ron=s question or Ron made the statement that we had a presentation on the analysis. We had a presentation on the wear and a discussion of what they are going to do.

MEMBER STETKAR: But there=s some stuff saying preliminary information from the analysis. That could lead you to the conclusion that they presented.

MEMBER BALLINGER: My words were not sufficiently accurate.

CHAIRMAN SKILLMAN: I understood what you meant.

MEMBER RICCARDELLA: My impression is the analysis has been done. It just hasn=t been submitted. That=s my understanding.

MEMBER STETKAR: Lindsay.

MS. ROBINSON: We can actually have the reviewer who is handling this one. We did get the response and again the response was dated November 24, 2014. So the staff is currently evaluating the response that was provided. But Roger here can provide maybe a little more insight.

MR. KALIKIAN: Yes. Hi. I=m Roger Kalikian and I=m the reviewer for the exam. They did provide a summary of the analysis. They did say they completed the analysis. And they also mentioned that they are continuing to evaluate to see how the analysis will impact the LRA. And they would submit that information to us when it=s completed. But we just got a brief summary and nothing else.

CHAIRMAN SKILLMAN: Please continue, Lindsay. Thank you.

MS. ROBINSON: The results of the staff=s review will be documented in the final SER and discussed during the full Committee meeting. Next slide.

SER Section 4 identifies Time Limited Aging Analysis or TLAAs. Section 4.1 documents the staff=s evaluation of the Applicant=s identification of applicable TLAAs. The staff evaluated the Applicant=s basis for identifying those plant-specific or generic analysis that needed to be identified as TLAAs and determined that the Applicant has provided an accurate list of TLAAs as required by 10 CFR 54.21(c)(1).

Sections 4.2 through 4.7 document the staff=s review of the applicable Byron and Braidwood TLAAs as shown. Based on its review of the information provided by the Applicant and pending the resolution of one open item, the staff concludes that the TLAAs were either (a) remain valid for the period of extended operation; (b) have been projected to the end of the period of extended operation; or (c) the effects of aging on those intended functions will be adequately managed for the period of extended operation as required by 10 CFR 54.21(c)(1)(I), (ii) or (iii) respectively. Next slide.

CHAIRMAN SKILLMAN: Let=s just hold on for a second here.

MS. ROBINSON: Yes.

CHAIRMAN SKILLMAN: Ron, did you want to ask a question about 4.5 on that slide.

MEMBER BALLINGER: This is the tendon pre-stress analysis. I was concerned about what happened at North Anna where you ended up with a tendon getting blown up basically by hydrogen embrittlement and releasing a tension. And it=s because the grease that=s in that conduit in the tendon is a high pH grease that=s designed to absorb moisture to maintain the pH high enough.

There=s a replacement. You=re supposed to inspect and replace that grease. So I was concerned and just wondering if there=s a program in place to do that inspection and replace that grease. A lot of times folks don=t do it. It=s pretty onerous and ugly and difficult and dirty and everything else.

But you=re required to have X number of those tendons in place for containment pressure maintaining. And if all of a sudden one of those tendons goes, the shock to the system, I=m wondering whether or not there=s a danger. We=ve seen these separations of concrete, the layers of concrete, around the rebar. I=m just curious as to how that=s being handled.

MS. ROBINSON: Is anybody from Exelon able to address that?

MR. GALLAGHER: Yes, we can answer that question. Jim Annett.

MR. ANNETT: My name is Jim Annett. I=m on the License Renewal Team. I think you had a couple questions in there. I=ll first talk about the grease in the tendons. The grease used at Byron and Braidwood is like the P-4 version of the grease versus like the P-0. And that starts with a higher alkalinity level.

So our acceptance criteria is a higher alkalinity level at Byron and Braidwood. So the grease level is always maintained at a higher alkalinity level at Byron and Braidwood. And when they do the sampling, it=s supposed to -- They have done grease replacements at Byron and Braidwood also. But they=ve never gotten to essentially like a zero level.

MEMBER BALLINGER: Okay. So it=s part of the aging management program to maintain that high pH.

MR. ANNETT: Yes, it is.

MEMBER BALLINGER: Okay.

CHAIRMAN SKILLMAN: Dr. Ballinger, you=re good.

MEMBER BALLINGER: Yes. Good.

CHAIRMAN SKILLMAN: Okay. Lindsay, go ahead. Thank you.

MS. ROBINSON: Thank you. Next slide. We=re on slide 16. Section 4 contains one open item. Open Item 4.3-1 is related to environmentally assisted fatigue locations for reactor coolant pressure boundary components. The Applicant performed a review of all four units of all applicable reactor coolant pressure boundary components with a Class 1 fatigue analysis to determine the plant-specific leading locations to be monitored by the fatigue monitoring program for EAF. However, the Applicant did not demonstrate that its methodology for selecting those locations provided assurance to the location that the locations were bounding.

In the Applicant=s methodology, the staff identified the following issues: (a) the Applicant=s justification for selecting one material to bound other materials and (b) the Applicant=s basis for screening out a component with a higher environmentally assisted cumulative usage factor value than the leading location.

By a letter dated October 28, 2014, the staff issued a follow-up RAI for the Applicant to demonstrate the specific components would not need to be monitored for EAF in the period of extended operation.

By letter dated November 25, 2014, the Applicant provided its response to the RAI. The response is currently under staff review. The staff=s conclusion will be documented in the final SER and discussed in the full Committee meeting. Next slide.

The staff=s conclusion will be provided in the final SER. Pending a satisfactory resolution of the open items and inspection issues, the staff will determine whether the requirements of 10 CFR 54.29(a) have been met for the renewal of Byron Station Units 1 and 2 and Braidwood Station Units 1 and 2.

This concludes our staff presentation. And we will now be available for any further questions.

CHAIRMAN SKILLMAN: Thank you, Lindsay.

Colleagues, may I ask if you have questions for the NRC staff please?

MEMBER STETKAR: Yes. I have a couple. One is back to the condensate storage tanks. We heard from the Licensee that they plan to inspect the total of 25 locations distributed between the two CSTs at each unit; whereas, the guidance now, interim staff guidance, specifically says for each outdoor insulated tank. And I=m curious why the staff accepted this notion of AWell, I can look at 12 on one of them and 13 on the other and 25 between the two them is good enough. Or if I have maybe 15 tanks, perhaps I could look at one on each one of them or a couple on each one of them and somehow count up to 25 that way.@ I=m curious why you accept this sort of notion of distributed inspections when you know we=ve pretty already established that the tanks are not identical in terms of their life history.

MS. ROBINSON: We can have the reviewer, Mr. Holston, come in and respond to your question.

MR. HOLSTON: Yes, this is Bill Holston,

Technical Reviewer for the Division of License Renewal. We accepted the 25 total per site. Because when we were writing the interim staff guidance, a typical plant has six outdoor tanks, usually two fuel tanks, maybe even more than that, two fire water tanks, two condensate storage tanks.

In the case of both Byron and Braidwood, they only had two outdoor tanks. They don=t have fire water storage tanks. The diesel storage tanks are inside. So a sample population of 25 is adequate.

The sample population of 25 is consistent with other aging management programs such as the internal surfaces program, the one-time inspection program and selective leeching program. A total population of 25 establishes reasonable assurance. All four of the tanks, the final point is that all four of the tanks were susceptible to water underneath the lagging in the license renewal application operating experience examples for all four of them. So we considered that the environmental conditions between the insulation and the tank sides were representative amongst the four tanks.

MEMBER STETKAR: I guess I still don=t understand your rationale. For the record I=ll read into Section (e)(iii)(c) of the License Renewal ISG-2012-02. It states AFor each outdoor insulated tank and indoor insulated tanks exposed to condensation because the in-scope component is being operated below the dew point, GALL report AMP XI.M-29 was revised to recommend removal of insulation from either 25 one square foot sections or 20 percent of the surface area and inspecting the exterior surface of the tank.@ That doesn=t say we sort of sample 25 somewhere around the total portion of the site. It says I look at each tank.

MR. HOLSTON: That=s correct. And I was actually the author of that interim staff guidance.

MEMBER STETKAR: Good.

MR. HOLSTON: And an interim staff guidance just like the GALL report is a set of recommendations. It=s not a set of requirements. The applicant can take exception to that and in this case the applicant stated that they wanted to do 25 total inspections at the site. And we found that 25 given the reasons I just explained at the beginning of the response was adequate in this situation.

Where you used an example of what is the plant had 16 tanks. Well, we would have come to a different conclusion if the plant had 16 tanks. In fact, this plant has two outdoor tanks.

MEMBER STETKAR: Okay. Thank you.

The only other one that I had and I=ll ask the staff about this. I=m going to ask the licensee, but we=re good on time. In their program for monitoring neutron-absorbing material in the fuel pool, the report noted that the -- I=ll probably get the terminology wrong. So just bear with me here -- placement of the coupons, the coupons are supposed to be placed in the middle of the most recently renewed fuel. So they would get the highest irradiation. And yet the experience has been that they haven=t always done that or I don=t know whether it=s haven=t always or perhaps never.

And now they=ve committed -- It says, AThe Applicant stated that prior to the period of extended operation an enhancement will be implemented to maintain the coupon exposure such as bounding for the raw material and spent fuel rods.@ In other words, sometime before 2026, they=re actually going to make sure they do this right.

Have they started to do it right now? I mean, how do we know that the coupons provide a bounding assessment of that material for the next 15 years?

MS. ROBINSON: I believe we have a reviewer who is on the line.

MEMBER STETKAR: Good.

MS. ROBINSON: Who may be able to address that. Is it still on listening mode?

PARTICIPANT: It=s open.

MS. ROBINSON: It is. Aloysius.

MR. OBODOAKO: Yes, this is Aloysius Obodoako in the Division of Engineering. I reviewed this program. Well, I supported the review of this program during the audit and also the aging management program. I=m currently looking for the response to that through my documents. It looks like I=ll have to get back to you about that response.

MEMBER STETKAR: Okay. I=m not sure. I=m more concerned about how are they monitoring it currently which is really more an issue of a current licensing rather than with the period of extended operation.

MS. ROBINSON: I think Exelon actually -- There=s somebody that can address that.

MR. GALLAGHER: Yes, Dylan Cimock can answer that question.

MR. CIMOCK: Dylan Cimock, License Renewal Team for Exelon. Just to clarify, Byron and Braidwood did implement an accelerated irradiation schedule at the beginning of the installation of the racks which includes surrounding the coupon tree on all sides with freshly discharged fuel for the first five cycles. So that was an importance of the manufacturer=s recommendations and both stations did satisfy that initial requirement.

We received an additional RAI asking how we will ensure that going forward. So we enhanced our program to state that we will maintain those coupons in that configuration going forward prior to testing.

MEMBER STETKAR: You said during the first -- When did you rerack the pools?

MR. CIMOCK: Byron and Braidwood, it was approximately 2000-2001.

MEMBER STETKAR: Okay. So you had the accelerated irradiation through let=s say 2005-2006-2007 time period, right?

MR. CIMOCK: Yes.

MEMBER STETKAR: The first five years roughly. But since then they=ve not been in that configuration. Is that correct?

MR. CIMOCK: That is correct.

MEMBER STETKAR: Okay. But going forward

from now or going forward from 2026, you=re going to ensure that they=re in an accelerated irradiation. In other words, that they received the highest performance.

MR. CIMOCK: The manufacturer=s recommendation was for the initial five cycles which would ensure that they were bounding for the duration of the racks which we assume for the existing license they would remain bounding.

MEMBER STETKAR: Okay.

MR. CIMOCK: Now going forward they are currently in a bounding condition. We are committing to maintaining those in a bounding condition through the PEO.

MEMBER STETKAR: Thank you. That clarified. Thanks. That helps.

CHAIRMAN SKILLMAN: Colleagues, any additional questions for the NRC staff please?

Hearing none, are there individuals in the audience that would like to ask a question or make a statement please?

Hearing none on the telephone line that is now open, are there any members of the public or others that would like to make a statement or ask a question please?

If you=re out there, would you please acknowledge your presence?

(No response.)

Thank you. Hearing no comments, would you please close the line?

SUBCOMMITTEE DISCUSSION

CHAIRMAN SKILLMAN: As a final activity here from my colleagues around the table, do you have any questions either for the staff or for the Applicant for these four units at two sites?

MEMBER RICCARDELLA: I don=t have any further questions. Thank you.

MEMBER RAY: No.

MEMBER POWERS: No.

MEMBER BALLINGER: No.

MEMBER STETKAR: Mr. Chairman, I just want to congratulate the staff. I think you guys did really well actually on the audits and inspections. It=s pretty onerous to try to get four units, your hands around four units, with differences and similarities. I was actually really impressed with the review effort. I just wanted to make that statement.

MEMBER POWERS: I think the Applicant did good because the project leader here is a graduate of my course.

MS. ROBINSON: Yes, that is absolutely correct.

MEMBER POWERS: That=s what led to --

MEMBER STETKAR: Yet again in your debt, Dr. Powers.

(Laughter.)

CONSULTANT BARTON: I think the Applicant did a terrific job of putting this whole thing together. It was a real good presentation.

CHAIRMAN SKILLMAN: I want to echo that. I want to thank the Exelon team, the Byron team, the Braidwood team. This has been an enormous amount of work and we understand that it has been. And it=s been an enormous amount of work for the staff, for the region and for the team here in Rockville. Thank you.

MEMBER POWERS: I would say let=s encourage them not to do this again. There are too many points at one time.

CHAIRMAN SKILLMAN: Those of us who did the reviews were juggling four units, two sites, permutations and combinations, what are the AMPs, where do they overlap, where are they separate, why are they separate. And you=ve done a great job in clarifying those distinctions and differences. So I thank you very much.

With that, I=m going to wish all safe travels and I=m going to stop this meeting. We are adjourned. Thank you.

(Whereupon, at 11:25 a.m., the above-entitled matter was concluded.)

Byron

Byron Station, Units 1 and 2

Braidwood

Braidwood Station, Units 1 and 2

License Renewal Application

ACRS Subcommittee Presentation
December 03, 2014

Exelon.

Introductions

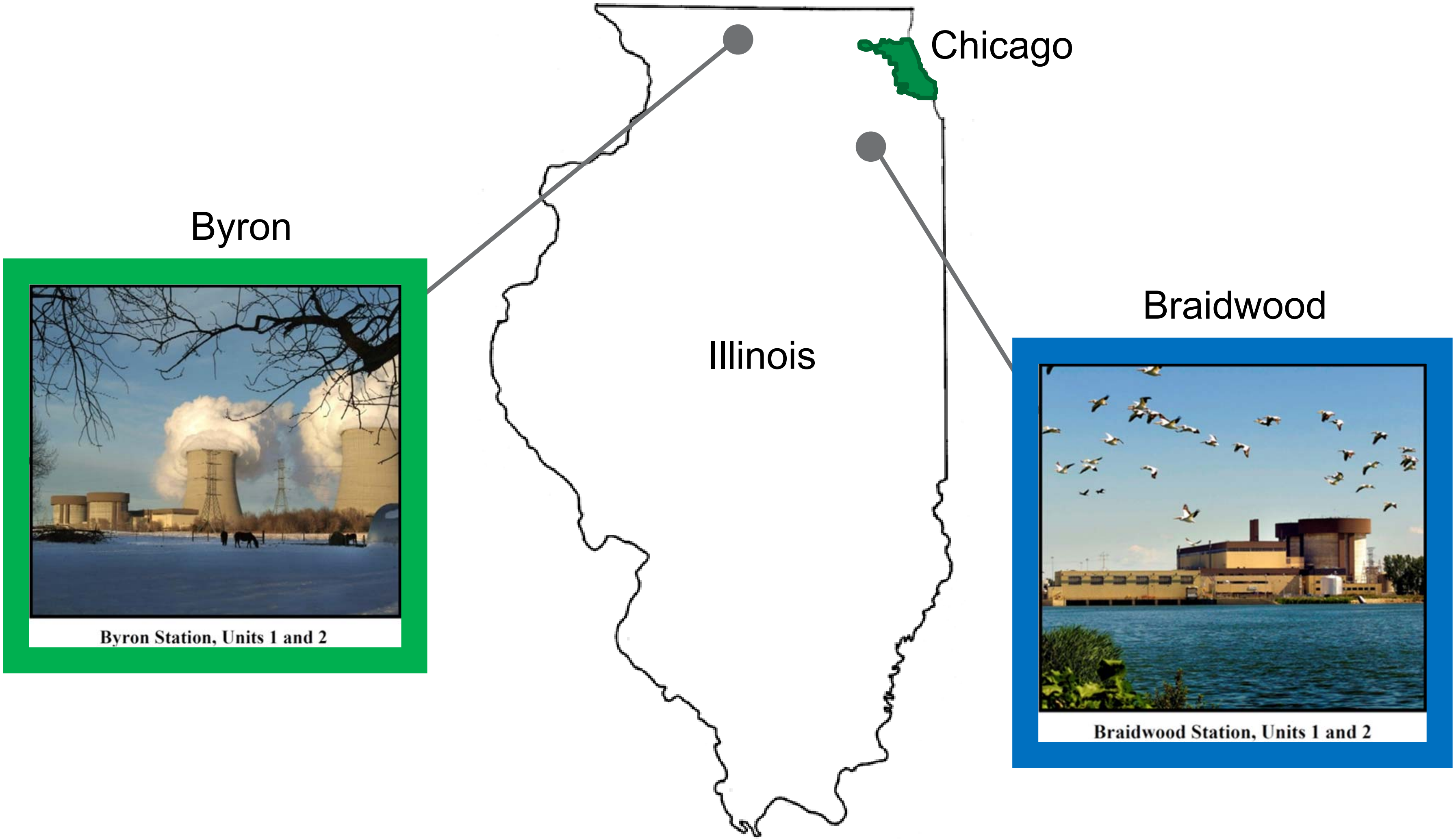
• Mike Gallagher	VP, Exelon License Renewal
• John Bashor	Braidwood Engineering Director
• Albert Piha	LR Mechanical Manager
• Ed Blondin	Byron Sr. Mgr. Design Engineering
• John Hufnagel	Project Licensing Engineer

Agenda

• Introductions	Mike Gallagher
• Station Descriptions and Overview	John Bashor
• GALL Consistency and Commitments	Albert Piha
• Open Items	
– EAF Screening Methodology	Albert Piha
– CRDM Housing Wear	Ed Blondin
• Items of Interest from Region III Inspections	
– Visual Examination of Concrete Containment	Albert Piha
– CRDM Seismic Support Assembly	Albert Piha
– Flux Thimble	John Bashor
• Closing Remarks	Mike Gallagher

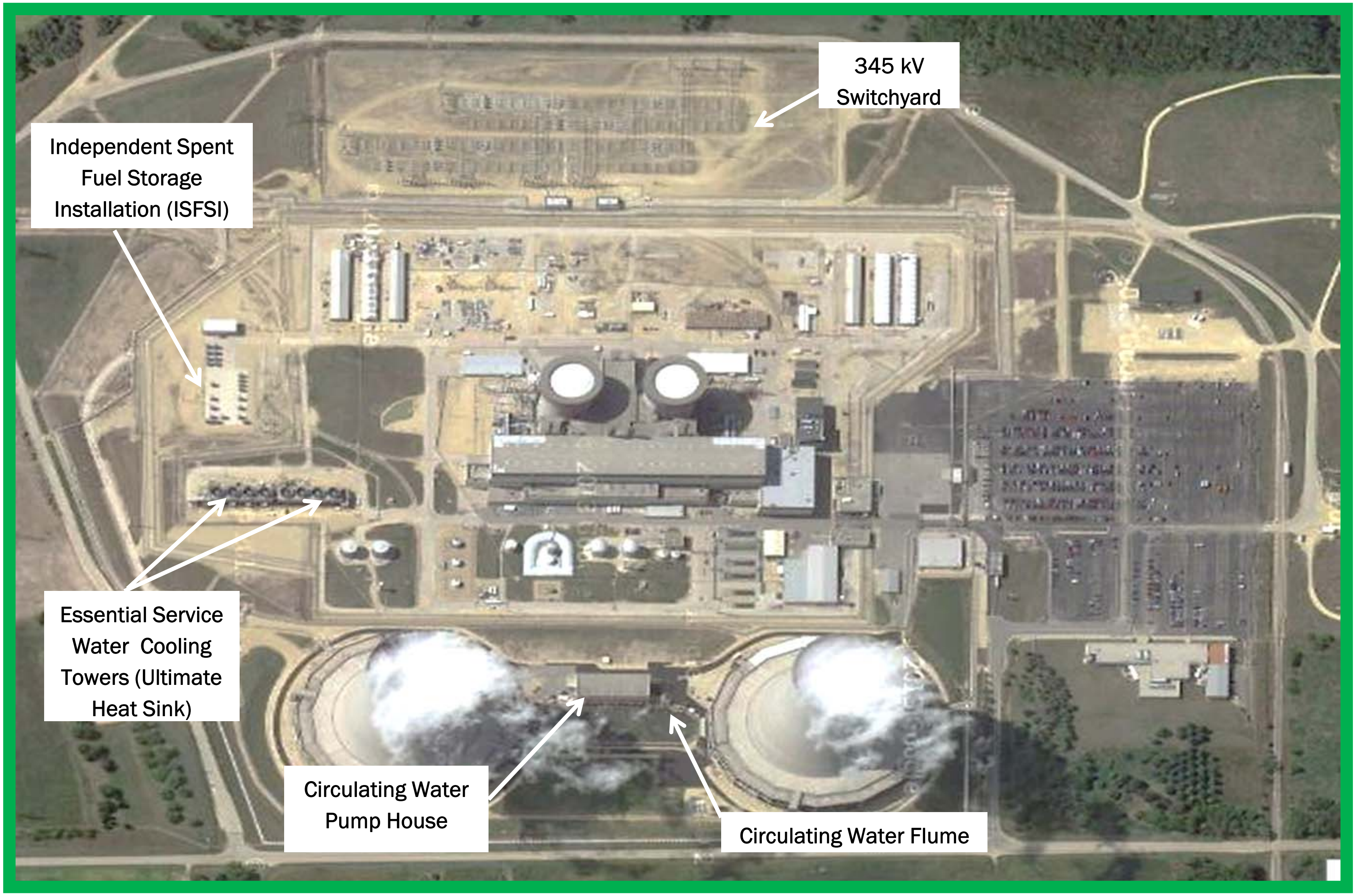
Exelon.

Byron and Braidwood Station Locations



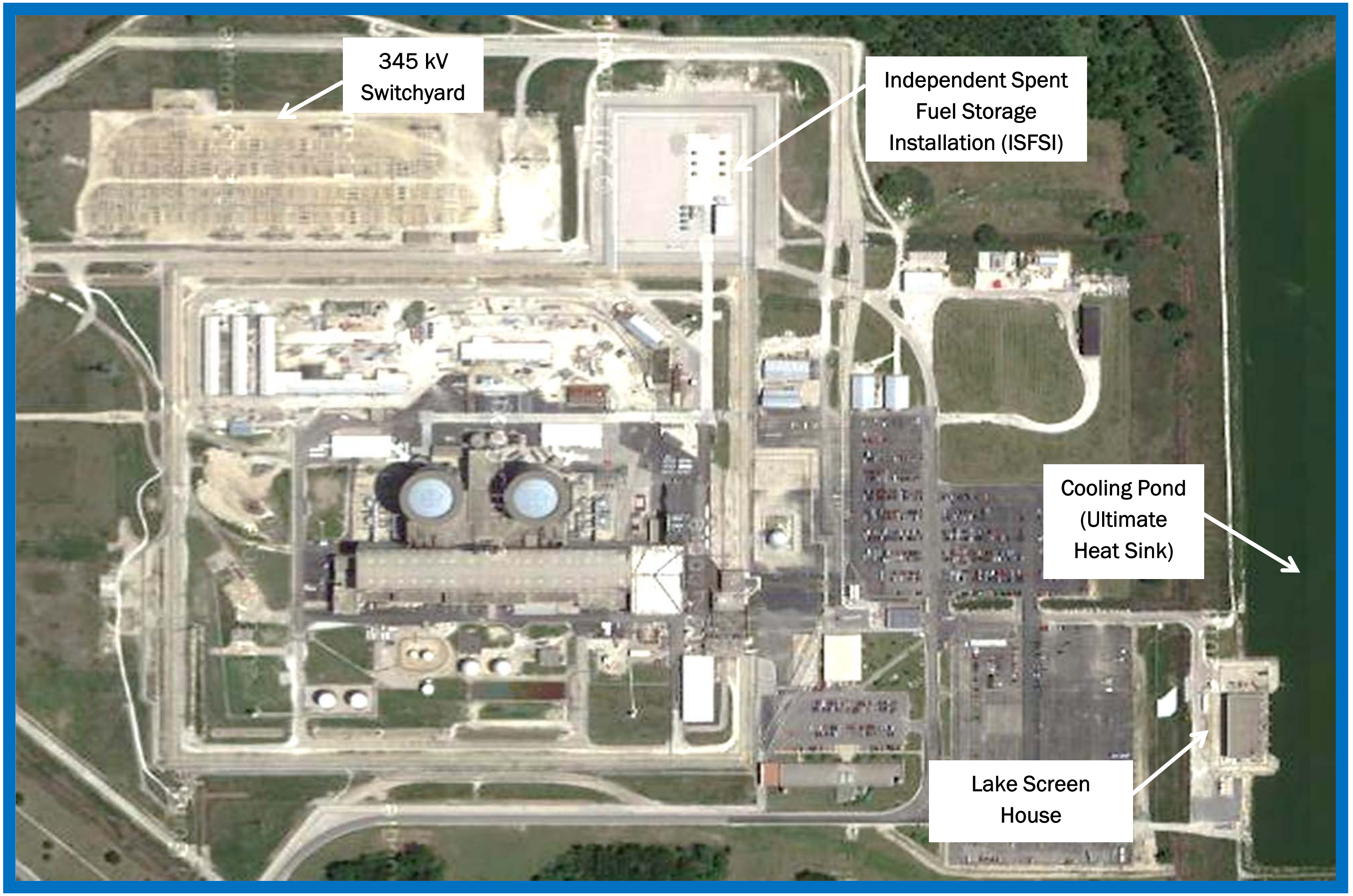
Exelon.

Byron Station



Exelon

Braidwood Station



Station Overview

	Byron		Braidwood	
	Unit 1	Unit 2	Unit 1	Unit 2
Initial License Date	10/31/84	11/06/86	10/17/86	12/18/87
5% Power Uprate to 3586.6 MW_t	2001	2001	2001	2001
1.63% Measurement Uncertainty Recapture (MUR) 3645 MW_t	2014	2014	2014	2014
Steam Generator Replacement	1998	-	1998	-
ECCS Recirculation Sump Screens	2006	2007	2007	2006
Spent Fuel Rack Replacements	2000		2001	
Independent Spent Fuel Storage Installation (ISFSI)	2009		2011	
Current License Expiration Date	10/31/24	11/06/26	10/17/26	12/18/27

Exelon.

GALL Revision 2 Consistency
and
License Renewal Commitments

Byron Station, Units 1 and 2

Braidwood Station, Units 1 and 2

GALL Consistency and Commitments

- Submittal based on GALL, Revision 2
- 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"

	Byron	Braidwood
Total AMPs	45	44
AMPs Consistent with GALL	38	37
AMPs with Exception to GALL	7	7
Commitments	47	46

Exelon.

Open Items

Byron Station, Units 1 and 2

Braidwood Station, Units 1 and 2

Open Item

OI 4.3-1: Environmentally Assisted Fatigue (EAF)

NRC Staff requested clarity on screening methodology

- Exelon/Westinghouse used a screening methodology to determine leading locations for EAF. These include NUREG/CR-6260 locations and those locations determined to be more limiting than the 6260 locations.
- Addressed open Staff questions on methodology:
  - Provided additional justification that the leading material locations will continue to bound eliminated material locations after refined analysis
  - Provided justification why a steam generator component was removed from consideration as a leading component when its screening CUF_{en} was higher than the selected leading location
  - Provided additional instances and justification for component locations removed from consideration as a leading component when its screening CUF_{en} was higher than the selected leading location
- Exelon has provided the information to the staff to address this issue in response to RAI 4.3.4-3b dated 11/25/2014

Open Item

OI 3.0.3.1.3-1: ASME Section XI, Subsections IWB/IWC/IWD

Control Rod Drive Mechanism (CRDM) Housing Wear

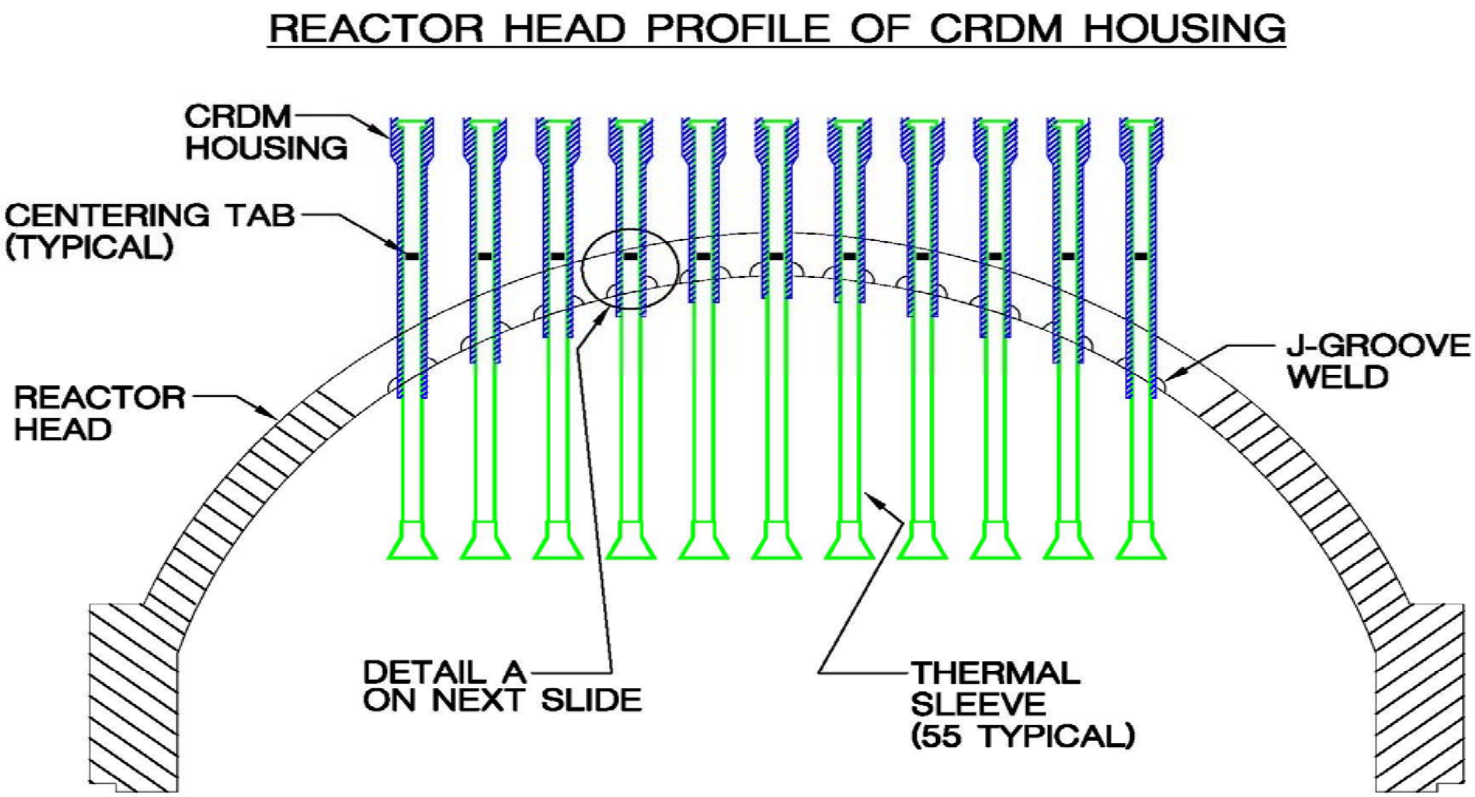
- The Staff needed additional information regarding aging management of CRDM Housing wear in the following areas:
  - Results of CRDM Housing wear analysis
  - CRDM Housing wear acceptance criteria

- Exelon has provided information to the Staff to address this issue in an updated response to RAI B.2.1.5-1a dated 11/24/2014

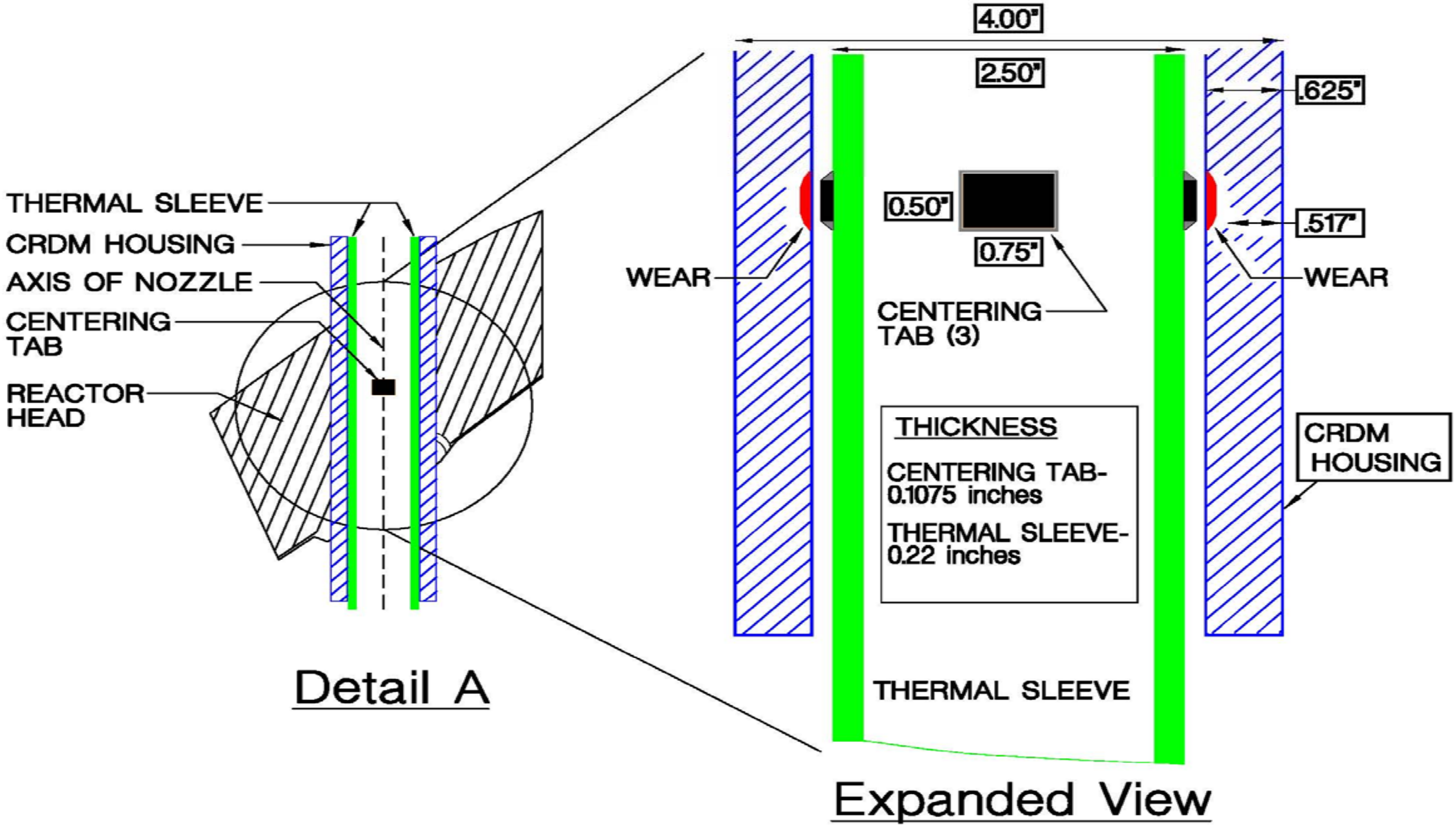
Exelon.

Overview of CRDM Housing Wear

Thermal sleeve rotation causes wear of the centering tabs and CRDM housings. The rotation is due to cooling flow through the reactor vessel head region.



CRDM Housing Wear Details



Exelon.

CRDM Housing Wear Analysis

- Finite element analysis and stress calculations were performed
  - Performed in conformance with applicable ASME Code requirements
    - ASME Code Section III, Subsections NB-3221 through NB-3226
    - Evaluated for required ASME Code conditions (Design, Normal, Upset, Emergency, Faulted, Test)
  - UFSAR requirements (Transients, Loading, Allowable Stresses)

Summary and Conclusions

- CRDM housing is acceptable considering applicable ASME Code requirements for Class 1 components
- PWROG analysis concluded CRDM housings are acceptable with maximum wear through the period of extended operation
- Based on the CRDM housing analysis, no additional aging management activities are required to manage the wear on the CRDM housing

Items of Interest from Region III Inspections

Byron Station, Units 1 and 2

Braidwood Station, Units 1 and 2

Item of Interest –
Visual Examination of Concrete Containment Structures

Issue:

Staff requested information to verify that sufficient visual resolution capability will be used during visual examinations of concrete surfaces of containment structures.

- Exelon has provided the following information to the staff in response to RAI B.2.1.30-6 dated 11/21/2014:
  - Enhancement 4 of the ASME Section XI, Subsection IWL (B.2.1.30) aging management program has been revised to update IWL implementing procedures as follows:
    - Visual resolution capability for direct and remote examinations will be sufficient to detect concrete degradation at the levels described in Chapter 5 of ACI 349.3R.

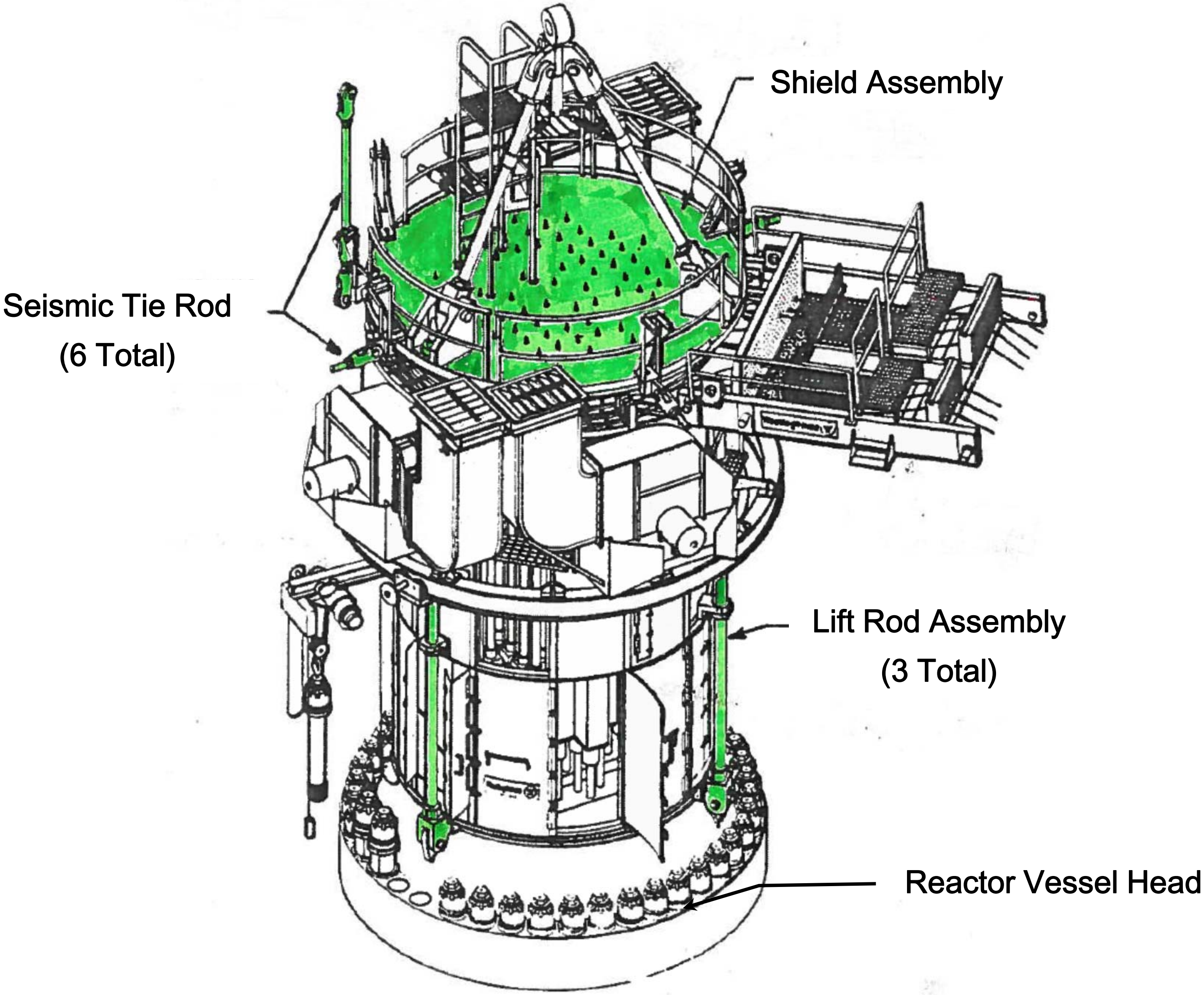
Exelon.

Item of Interest –
CRDM Seismic Support Assembly Aging Management

Issue:

CRDM seismic support assembly not in scope of the Section XI IWF Aging Management Program

CRDM Seismic Support Assembly Aging Management



Exelon.

CRDM Seismic Support Assembly Aging Management

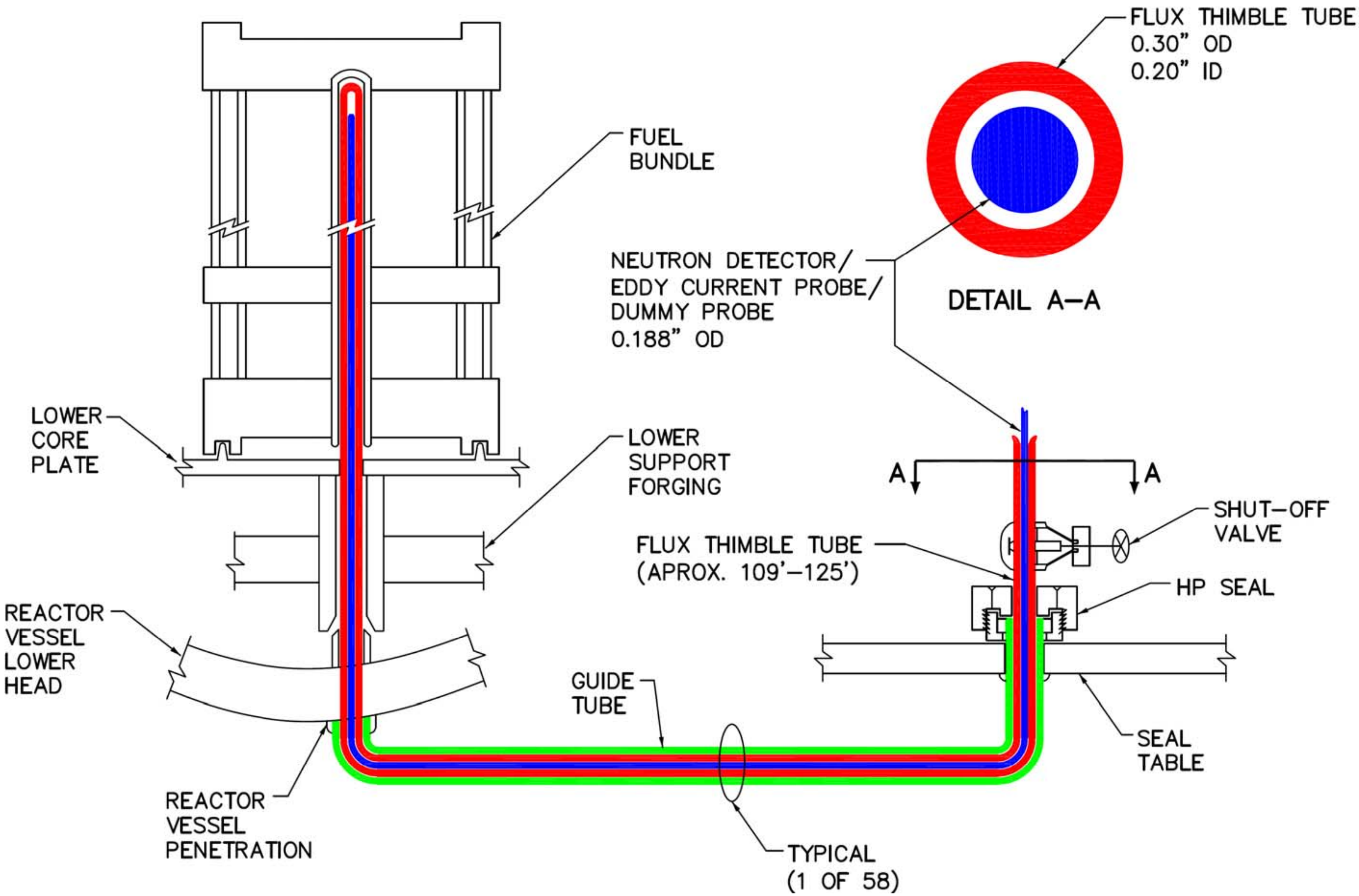
- Component of Interest
  - CRDM Seismic Support Assembly (SSA) is a sub-element of the Integral reactor vessel head assembly (IHA)
- Original treatment within LRA
  - External Surfaces Monitoring and Boric Acid Corrosion AMPs credited for aging management of all elements of the IHA
- Aging management approach challenged during IP-71002
  - CRDM SSA was not included within the scope of the ASME Section XI, Subsection IWF program
  - Exelon letter of August 29, 2014 added CRDM SSA to scope of IWF program for license renewal aging management
- Follow-up RAI B.2.1.31-4 on use of high strength bolting
  - Exelon letter of October 16, 2014 confirmed high strength bolting is not used in CRDM SSA

Item of Interest –
Braidwood Flux Thimble Tube Inspection Program

Issue:

During recent refueling outages, eddy current data has not been obtained as planned in support of the Flux Thimble Tube Inspection Program

In-Core Flux Monitoring System



Corrective Actions

- Determine Cause of Issue
  - Evaluate if Flux Thimble Tube Cleaning is Effective/Necessary
  - Perform Mock-Up Testing Using Spare Flux Thimble Tube
  - Extract and Analyze Restricted Flux Thimble Tube

- Improved Eddy Current Testing Equipment
  - More Rigid Drive Cable
  - Smaller Eddy Current Probe

- Flux Thimble Tube Replacement
  - Larger Inside Diameter Flux Thimble Tube

Basis for Adequacy of Current Program

- Program relies on periodic eddy current testing and conservative projections in accordance with:
  - NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors”
  - WCAP-12866, “Bottom Mounted Instrumentation Flux Thimble Wear”

- Eddy current testing frequency or need for replacement are based on conservative wear projections

- Commitment added to replace flux thimble tubes if required data is not obtained

	Spring 2014	Spring 2015	Fall 2015	Fall 2016	Spring 2017	Ongoing
Unit 1		17		41		Every 3 Refuel Outages
Unit 2	7 Completed		29		22	

Exelon.

Conclusion

- Current flux thimble tube inspection program complies with NRC Bulletin 88-09 and all in-service flux thimble tubes were evaluated as being acceptable
- Commitment added to replace flux thimble tubes if required data is not obtained
- Appropriate corrective actions are in progress to ensure eddy current data is obtained as planned
- Additional information submitted to NRC

Closing

Questions ???

Byron

Byron Station, Units 1 and 2

Braidwood

Braidwood Station, Units 1 and 2

License Renewal Application

ACRS Subcommittee Presentation

December 03, 2014

Exelon.

Advisory Committee on Reactor Safeguards License Renewal Subcommittee

Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2 (BBS) Safety Evaluation Report (SER) with Open Items

Lindsay Robinson, Project Manager
Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of BBS license renewal review
- Region III License Renewal Onsite Inspection
- 71002 Inspection Issues
- SER Section 2, Scoping and Screening Review
- SER Section 3, Aging Management Review
- SER Section 4, Time-Limited Aging Analyses

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Protecting People and the Environment

License Renewal Review
(Audits and Inspections)

- **Scoping and Screening Methodology Audit**
  - Byron: July 29 - August 2, 2013
  - Braidwood: December 2-4, 2013
- **Aging Management Program (AMP) Audit**
  - Byron: August 19-30, 2013
  - Braidwood: October 30-31, 2013, and Dec 2-6, 2013
- **Environmental Audit**
  - Byron: September 17-19, 2013
  - Braidwood: November 18-20, 2013
- **Region III 71002 Inspection (Scoping and Screening & AMPs)**
  - Byron: August 4-8, 2014, and August 18-22, 2014
  - Braidwood: Sept 15-26, 2014

SER Overview

- **SER with Open Items (OIs) was issued October 30, 2014**

- **BBS SER contains 2 OIs:**
  - OI 3.0.3.1.3-1 CRDM Nozzle Wear
  - OI 4.3-1 Environmentally Assisted Fatigue (EAF) in Class 1 Components

- **The final SER is scheduled for publication April 2015**

71002 Inspections

- **Scope**
  - Regulated Events
  - Non-Safety Systems affecting Safety Systems
  - Aging Management Programs
- **Byron Inspection**
  - Aug. 2014: Team Inspection (6 inspectors) on-site for 2 weeks
- **Braidwood Inspection**
  - Sept. 2014: Team Inspection (5 inspectors) on-site for 2 weeks

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71002 Inspections

Overall Inspection Results

- Material condition of SSCs – Good
- Application changes to some AMPs
- Identified issues for further review:
  - XI.S3 ASME Section XI, Subsection IWF
  - XI.S2 ASME Section XI, Subsection IWL
  - XI.M37 Flux Thimble Tube Inspection

71002 Inspections

- **Conclusions:**
  - Scoping and screening performed in accordance with 10 CFR 54
  - Information used to prepare the license renewal application was retrievable, auditable, and consistent with 10 CFR 54
  - Existing programs are generally effective in managing aging effects
  - Actions to address enhancements and new programs are being tracked for completion
  - Reasonable assurance that aging effects will be managed and intended functions maintained, subject to satisfactory resolution of open issues

71002 Inspection Issue

CRDM Seismic Support Assembly Bolting

- **Issue:** LRA revised to include CRDM Seismic Support Assemblies but did not specify whether the assemblies included high-strength bolting greater than 1” diameter
- **Concern:** Aging management of high-strength bolting
  - Applicant responded that there is no high-strength bolting used in CRDM seismic supports
  - This issue is resolved

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71002 Inspection Issue

IWL Visual Examinations

- **Issue:** Currently, visual inspections of some areas of concrete deterioration are conducted remotely with the use of an optical aid.
- **Concern:** Visual resolution capability of optical aids to detect and quantify degradation for comparison against quantitative acceptance criteria described in ACI 349.3R.

71002 Inspection Issue

Flux Thimble Tube Inspection

- **<u>Issue</u>:** The applicant failed to complete inspections at Braidwood Units 1 and 2 during the most recent outages.

- **<u>Concern</u>:** AMP may be inadequate

SER Section 2 Summary

- **Structures and Components Subject to Aging Management Review**
  - Section 2.1, Scoping and Screening Methodology
  - Section 2.2, Plant-Level Scoping Results
  - Sections 2.3, 2.4, 2.5 Scoping and Screening Results

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SER Section 3: Aging Management Review

- **Section 3.0 – Aging Management Programs**
- **Section 3.1 – Reactor Vessel, Internals, and Reactor Coolant Systems**
- **Section 3.2 – Engineered Safety Features Systems**
- **Section 3.3 – Auxiliary Systems**
- **Section 3.4 – Steam and Power Conversion Systems**
- **Section 3.5 – Containments, Structures, and Component Supports**
- **Section 3.6 – Electrical and Instrumentation and Controls Systems**

SER Section 3

3.0.3 – Aging Management Programs

LRA identified:	Staff's review identified:
• 13 new programs − 11 consistent − 2 consistent w/ exceptions • 32 existing programs − 9 consistent − 18 consistent w/ enhancements − 5 consistent w/ enhancements and exceptions	• 13 new programs − 11 consistent − 2 consistent w/ exceptions • 32 existing programs − 6 consistent − 21 consistent w/ enhancements − 5 consistent w/ enhancements and exceptions

SER Section 3 Open Item

OI 3.0.3.1.3-1 CRDM Nozzle Wear:

- **<u>Issue</u>**: CRDM penetration nozzle wear not managed.
- **<u>Open Item</u>**: Applicant to confirm CRDM penetration nozzle wear will be adequately managed.

SER Section 4: TLAA

- 4.1 Identification of TLAAs
- 4.2 Reactor Vessel Neutron Embrittlement Analysis
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electric Equipment
- 4.5 Concrete Containment Tendon Prestress Analyses
- 4.6 Containment Liner Plate, Metal Containments, and Penetration Fatigue Analyses
- 4.7 Other Plant-Specific TLAAs

SER Section 4 Open Item

OI 4.3-1 Environmentally Assisted Fatigue in Class 1 Components:

- **<u>Issue</u>:** Insufficient justification for selecting leading locations
  - how one material bounds other materials
  - basis for comparison of CUF_{en} values
- **<u>Open Item</u>**: Applicant did not demonstrate why specific components would not need to be monitored for EAF

Conclusion

Pending satisfactory resolution of the open items and inspection issues, the staff will determine whether the requirements of 10 CFR 54.29(a) have been met for the license renewal of Byron Station, Unit 1 and Unit 2, and Braidwood Station, Unit 1 and Unit 2.