UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

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WEDNESDAY, APRIL 1, 2009

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ROCKVILLE, MD

The Subcommittee convened in Room T2B3 in the Headquarters of the Nuclear Regulatory Commission, Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Dr John Stetkar, Chair, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

JOHN W. STETKAR, Chair

JOHN D. SIEBER

SAM ARMIJO

WILLIAM J. SHACK

MARIO V. BONACA

SAID ABDEL-KHALIK

CHARLES H. BROWN, JR.

HAROLD B. RAY

MICHAEL T. RYAN

CONSULTANT TO THE SUBCOMMITTEE PRESENT:

JOHN J. BARTON

NRC STAFF PRESENT:

BRIAN HOLIAN

JAY ROBINSON

EVELYN GETTYS

SAM LEE

GLENN MEYER

ROBERT SUN

XUHAN XI

MATT YODER

DUC NGUYEN

ALSO PRESENT:

MICHAEL GALLAGHER

STEVE QUEEN

FRED POLASKI

MARK MILLER

GENE NAVARTIL

DEBORA SPAMER

STU GETZ

MARJORIE AAMODT

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

1:29 p.m.

CHAIR STETKAR: The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I'm John Stetkar, Chairman of the Three Mile Island Plant License Renewal Subcommittee.

ACRS members in attendance are Jack Sieber, Sam Armijo, Bill Shack, Mario Bonaca, Said Abdel-Khalik, who made me too nervous, Mike Ryan. Who else is here? Charlie Brown and Harold Ray.

Christopher Brown of the ACRS staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the license renewal application for the Three Mile Island Nuclear Station, the draft Safety Evaluation Report and associated documents. We will hear presentations from representatives of the Office of Nuclear Reactor Regulation and the applicant, Exelon Generation Corporation.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full Committee.

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the *Federal Register* on March 16, 2009.

We have received a request from one member of the public who wishes to make an oral statement over the phone. Ms. Marjorie Aamodt of the Committee on Health Aspects and Management of Nuclear Power requested ten minutes to make a statement regarding today's meeting. We've opened a bridge line of Ms. Aamodt.

Are you there?

MS. AAMODT: Yes, I'm here.

CHAIR STETKAR: Okay. Excellent.

MS. AAMODT: And I want to thank you, Chairman.

CHAIR STETKAR: Thank you.

What we'll do is we'll put the bridge line on mute so that you can listen in to the full proceedings of the meeting and then open the bridge line at the end of the meeting so that you can participate and make your statement.

MS. AAMODT: Well, I will be able to listen, though, all day, right?

CHAIR STETKAR: Oh, yes. Definitely.

Absolutely. You'll be able to listen to everything that's said.

And with that, if you can -- thank you.

A transcript of the meeting is being kept and will be made available as stated in the *Federal Register* notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee.

Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

We'll now proceed with the meeting and I call upon Brian Holian, of the Office of Nuclear Reactor Regulation to introduce the presents. Brian?

MR. HOLIAN: Thank you. Good afternoon. My name is Brian Holian. I'm the Director of the Division of License Renewal.

As the agenda states, I'll just make brief staff introductions and turn it over to the licensee, and then the staff presentation will follow.

To my left is Mr. David Pelton, the Branch Chief that includes the Three Mile Island application and review.

To his left is Mr. Jay Robinson, the

Senior Project Manager responsible for the TMI review.

And to his left is Mr. Glenn Meyer, the Senior Reactor Inspector from Region I.

In general, you know following up on this morning's issue, Three Mile Island is similar to the Susquehanna as relatively clean from the number of open items or confirmatory items that the Subcommittee received. We do have one item that the staff will discuss during our presentation, which was similar to this morning, on dissolved oxygen. One confirmatory item where the staff in its peer reviews wants to confirm some of the information from TMI on that review. So you'll be hearing about that.

With that, I'll turn it over to Mr. Mike Gallagher, Vice President for License Renewal Projects for Exelon.

MR. GALLAGHER: Thanks, Brian.

Okay. Good afternoon. My name is Mike Gallagher and I'm the Vice President of License Renewal Projects at Exelon.

You can go to slide 2.

Before we get into today's presentation, I would like to introduce the presenters.

Steve Queen was the TMI Engineering Director during our license renewal application

preparation and is currently the Operations Director at TMI. Steve has over 25 years experience at Three Mile Island.

On our slide here we have Al Fulvio. Al, unfortunately, became ill yesterday and cannot present today. So presenting for Al will be Fred Polaski. And Fred is our Corporate License Renewal Manager. Fred has over 35 years of nuclear power plant experience including over 10 years in license renewal. Fred is an industry leader in the license renewal field.

Next we have Pat Bennett. Pat is our Mechanical Engineering Design Manager at TMI and has over 25 years experience at TMI.

And to my left is Chris Wilson, our Project Licensing Lead. Chris also has over 25 years experience in nuclear power plants.

In addition to our technical support personnel we have here today, we have Bill Noll. Bill is our site Vice President at Three Mile Island.

And we have Amir Shahkarami. Amir is our Senior VP of technical support and engineering at Exelon.

Slide 3 shows our agenda for the presentation. First, we will present to you the

highlights of the license renewal application.

Then we will present to you the one confirmatory item that was in the draft SER.

And then we'll present to you some topics of interest in aging management at TMI.

We believe we've developed a robust, high quality license renewal application. We also developed an overall effective aging management program to ensure continued safe operation at TMI.

We appreciate this opportunity to make this presentation and look forward to answering any questions you may have.

If we go to slide 5, I'll now give a brief overview of the TMI site. And I'll do this in the next slide, slide 6 looking at the site aerial view.

So Three Mile Island is an island that's in the Susquehanna River. It's in Londonderry Township and it's about ten miles southeast of Harrisburg, Pennsylvania.

In this photo the river flows north to south, which is left to right in this photo.

On the island, this is the Unit 1 cooling towers, the Unit 1 turbine building and the Unit 1 containment.

Unit 1 is a Babcock and Wilcox pressurized

water reactor.

Also located on the island is Unit 2. And here are the Unit 2 cooling towers, turbine building and containment.

And Unit 2 is owned by First Energy. Unit 2 has been shutdown since the March 28, 1979 accident and is currently in safe storage mode called Post Defueling Monitored Storage.

Unit 1 and Unit 2 are contained in a common security protected area and is controlled by Exelon. Exelon has access and use to all equipment and facilities needed for the safe operation of Unit 1.

For license renewal there were two structures that are owned by First Energy that are in scope. They are the Unit 2 fuel handling building, this structure right here, since it is a common building with the Unit 1 fuel handling building. And the Unit 2 diesel building, which is this structure right here, since it contains the Unit 1 station blackout diesel. These structures are all included in the Unit 1 aging management programs.

On this photo you can also see the switchyard, which is located on the island, and the intake structure/pumphouse.

If there's no questions, I'd like to then turn it over to Steve Queen who will go over the plant operating history.

MR. QUEEN: Good afternoon. My name is Steve Queen and I'm the Operations Director at Three Mile Island.

I'm going to give just a brief discussion of the operating history of the plant.

The unit started commercial operation in 1974 and we operated on one year cycles at that time until the TMI-2 accident in '79. At that point the unit was shutdown for five to six years to do the NUREG-0737 modifications.

On the restart, we went up in '88 by 1.3 percent power to 2568 and then went to two year operating cycles.

In 1999 the unit was sold to Pico and British Energy into a unity called AmerGen. And then we replaced the turbine rotors, the main transformers, our auxiliary transformers and a new reactor head.

We presented our license renewal application in 2008. And then we transferred our license in a name change only from AmerGen to Exelon.

The steam generators are scheduled for fall of 2009. We'll replace those.

And our operating history since 2001 has been two consecutive breaker to breaker runs. And we just recently started up in 2007 out of our outage and we've been continuously running since then until our 2009 outage, when again we'll replace our steam generators.

Unit capability factor has been about 95 percent during that time frame. And our current license expires in 2014.

With that, if there's no questions on the operating history.

MR. GALLAGHER: Okay. We'll turn it over to Fred Polaski.

MR. POLASKI: Good afternoon. I'm Fred Polaski with Exelon.

I would like to talk about and discuss the consistency of the TMI license renewal application as it compares to NUREG-1801, the NRC's GALL report and also briefly discuss how TMI will implement the commitments we've made as part of license renewal and then address the one confirmatory item that we have in the draft SER.

TMI and as part of the license renewal application identified 38 aging management programs. Twenty-four of these were consistent with the GALL

report and 14 are consistent with exceptions. The exceptions that we took in the TMI license renewal application were the same exceptions that have been taken on other license renewal applications and have been accepted by the NRC.

When we prepared our application and prepared our aging management programs and then compared them to the descriptions of the programs in the GALL report, any differences we identified we considered to be exceptions to the GALL report and presented them as such in the application.

Now just some examples of that. There are two exceptions where we credit EPRI reports. Since the GALL document was published in 2005 EPRI has updated those documents to later revisions. TMI implements the later revision, so we considered those as part of our exceptions because of the difference in the revision of the document.

Five of the exceptions are due to aging management programs that we expanded to include materials, environments and aging effects, more than what are those listed in the GALL report.

And as a final example there are two exceptions because the GALL report references NRC guidance documents which have been updated by the NRC.

But the latest revision to the GALL hasn't yet been updated to reflect those revisions. So we used the latest revision at the plant.

So by way of example, the point is here these revisions are minor in nature, they're not major technical issues, a lot of them dealing with revisions of existing documents.

On to slide 10. Oh, no, on the same one.

On commitments, all of our license renewal commitments are managed through Exelon's fleet wide commitment tracking program. This program implements the guidance provided in NEI 99-04, which is the Nuclear Energy Institute's guideline for managing NRC commitment changes.

We have made 43 commitments for the TMI license renewal application. Thirty-eight of these are the aging management programs that we described in the application that we'll be crediting for managing aging during the period of extended operation. And then there was five additional commitments that we made.

One is that we have committed to implement the pressurized water reactor vessel internals program once it has been approved. It is currently under development in the industry. TMI will submit our

inspection plans to the NRC once they're completed for their review and approval and we'll do that at least 24 months prior to entering the period of extended operation.

Second, TMI is committed to installing these new steam generators prior to entering the period of extended operation. Our commitment is to have them installed before 2014. As Steve mentioned, the plan is to do that in 2009.

We also will be submitting new reactor vessel pressure-temperature limit curves prior to entering the period of extended operation. The commitment also includes a commitment to submit those prior to reaching 29 effective full power years. The current pressure-temperature curves for TMI are only good for 29 EFPY. But TMI will reach 29 EFPY at about the end of the current license term. With real good operation it will be before, if there would be some problems it may be after. So the commitment covers it either way.

The fourth one is we've also committed to perform weld repairs throughout the building liner to correct some corrosion problems there. We've committed to do that prior to entering the period of extended operation.

And the last commitment is that we will continue to perform surveillance of the Boral test coupons for the spent fuel storage racks.

MR. BARTON: What are the extended corrosion of the liner?

MR. POLASKI: We've got an item we're going to discuss that in detail later, if you wouldn't mind holding off.

MR. BARTON: No problem.

MR. POLASKI: Okay.

CHAIR STETKAR: Fred, I had one question and I don't think you're going to -- on one specific exception that I kind of stumbled over and I wanted to understand it a little bit.

On fuel oil testing --

MR. POLASKI: Yes.

CHAIR STETKAR: -- you took an exception to testing the fuel oil in the 50,000 gallon fuel oil storage tank. And not having had the ability to figure out what fuel oil storage tank that 50,000 gallon storage tank: The first question is what does the 50,000 gallon tank supply because there seemed to be several fuel oil storage tanks?

MR. QUEEN: I'm Steve Queen, Operations Director.

The 50,000 gallon tank supplies actually a second tank, which is a 30,000 gallon tank. And that is the main supply tank to our emergency diesel generators.

CHAIR STETKAR: Okay.

MR. QUEEN: That 50,000 tank has the capability of supplying other things other than the emergency diesel generator storage tank, but that's its purpose.

CHAIR STETKAR: I'm just trying to sort it out in my head.

You said that the place that you sample is somewhere near the bottom of the tank. You said the draw off line, I think the words are "toward the bottom of the tank." And I believe that the discussion says something to the effect while you recirc the tank and you mix it up and then you sample it, which is conservative. And I'm not sure how that's conservative because you're sort of diluting the contaminants in the main volume of the tank. So I wasn't quite sure how that was conservative.

But I came across another commitment or part of another program that says "activities to periodically drain water and sediment from tank bottoms for the 50,000 gallon fuel oil storage tank,

the 30,000 gallon diesel fuel oil storage tank and the diesel fire pump 350 gallon tank," that's one of the enhancements to one of your programs. So I was curious if you can drain water from the bottom of the tank, why can't you sample from the bottom of the tank, or am I misinterpreting something here?

MR. POLASKI: We'd like to ask Mark Miller from Exelon to address that question.

MR. MILLER: Mark Miller from Exelon.

Yes. For the 50,000 gallon storage tank we do sample because its sampled weekly because it is the supply to the emergency diesel tanks, its sampled as part of the recirculation loop. And in that way because it's drawing off the normal pump suction for that tank, it's lower towards the bottom of the tank, we feel it does provide a representative sample of the oil. The other option that the program requires is a multilevel sample, which is lowering a sample container down through the top of the tank, popping the cork and pulling it up at a certain rate to get a multilevel representative sample. Because this is sampled weekly, that's not a practical thing to do from a safety standpoint and climbing ladders and things like that. So we took the exception to use this recirculation mode and grab a sample off that

line and use that as our equivalent sample to a multilevel sample.

CHAIR STETKAR: But does that mean -- I was trying to understand that in combination with what's called -- in the SER it's called enhancement 7. It's probably not numbered that way in your program.

MR. MILLER: You're referring to the draining, periodically draining water and sediment? Yes, that's another --

CHAIR STETKAR: Yes. It says "from the bottom of the tank."

MR. MILLER: Right. That's another requirement for the fuel oil program.

CHAIR STETKAR: It's a requirement?

MR. MILLER: Right.

CHAIR STETKAR: But can you physically do that from this tank?

MR. MILLER: Yes. Yes, there's drains. Those will be done from the drains.

CHAIR STETKAR: Why can't you sample from that drain then to see whether there's -- for the status of the oil in the bottom of the --

MR. MILLER: Well, I believe they are when they -- in some of the tanks at least, they do provide a sampling. And they do a visual for the presence of

water under draining water and sediment if there is any water and sediment.

MR. GALLAGHER: I think the question is--

CHAIR STETKAR: The question is if you can drain things from the bottom of the tank, why did you have to take the exception that you couldn't sample the oil at the bottom of the tank?

MR. MILLER: Well, it would be an exception to take a sample from the bottom since the requirement is a multilevel sample. A bottom sample wouldn't be considered multilevel.

CHAIR STETKAR: Oh, I understand. The exception is multilevel and not --

MR. MILLER: Right. Right. Not -- yes.

CHAIR STETKAR: Understand. Thank you. Thank you.

MEMBER BONACA: I have a question, too, regarding tanks. There's problem on one time inspections as inspections of the water chemistry, fuel oil chemistry, lube oil chemistry, air, gas whether the environment and here the concern -- one of the concern is loss of material. And, you know, one time exception typically has to do with a situation where you do not except to have a phenomenon so you do once to verify the case. But reading the operating

experience for these tanks you had a number of examples of loss of material. Could you expand on that? I mean why would you have just one time inspection rather than a program?

MR. QUEEN: The loss of material on tanks.

MEMBER BONACA: Fuel oil.

MR. QUEEN: Yes. And, Mark, why don't you --

MEMBER BONACA: Fuel oil, lube oil; it's only one time inspections you have under B.2.1.1.8.

MR. GALLAGHER: Right. So the question is why is the one time inspection sufficient?

MEMBER BONACA: Given that you had other history of some leaks here or there, why would you consider one time inspection rather than having a program to periodically inspect for loss of material?

MR. MILLER: Well, the reason there's a one time inspection program is -- it's basically to validate your chemistry programs and its specifically targeted for stagnant or low flow areas where there's no replenishment so you could maybe not have an effective chemistry program in those spots. So that's what the one time inspection program does, it looks at -- in the case of fuel oil it'll look at fuel oil piping and it'll find drain lines and vent lines and

things where chemistry will not be effective, or may potentially not be effective in managing the aging effects.

MEMBER BONACA: But you don't expect to find a problem?

MR. MILLER: Right. Right. You know, whereas the issues with the tanks are contaminates and things like that tend to settle in the fuel oil tanks and the fuel oil program is intended to prevent the accumulation of those kind of things and to verify by doing tank sampling and inspections that it's not occurring within the tanks itself. And then that's applied to the piping with verification to the one time inspection program.

MEMBER BONACA: Okay. So it really is not to the tanks itself, but the piping and the areas where you do not have significant flow --

MR. MILLER: Right.

MEMBER BONACA: -- to have -- which is consistent with your chemistry program? Okay.

Thank you.

CHAIR STETKAR: As long as we have you here, what tank is FOT-1?

MR. MILLER: Geez.

MR. QUEEN: This is our main fuel oil tank

for --

MR. MILLER: Is that the 50,000 gallon?

MR. QUEEN: 50,000 gallon tank.

CHAIR STETKAR: That is the 50,000 gallon tank? That's the one --

MR. QUEEN: Because FOT-2 -- FOT-1 is the main tank where we deliver fuel oil.

MR. MILLER: That's the 30,000 gallon tank?

MR. QUEEN: No. The 30,000 gallon tank--

MR. MILLER: Is FOT-8, I think.

MR. QUEEN: The 50,000 gallon tank and, David, FOT-1 is which -- 200,000 gallon. It's the main delivery tank. It's the main delivery tank for fuel oil.

MR. MILLER: And that's not in scope and it's not managed within the program, the 200,000 gallon tank. The 50,000 gallon tank is.

CHAIR STETKAR: Sorry.

MR. MILLER: No, that's okay. There's a whole string of tanks that all connect --

CHAIR STETKAR: No. I mean, that was the only one that was referred to by number. Everything else is by gallons.

MR. MILLER: Right.

CHAIR STETKAR: And I couldn't find anything in the FSAR that kind of correlated everything.

So continue. Thank you.

MR. GALLAGHER: Okay. Fred, I think you still have it.

MR. POLASKI: Yes, I still have it. Slide 10.

We had one confirmatory item from the NRC in the draft SER. The NRC requested information to confirm that the dissolved oxygen level in the reactor coolant during operation was less than 0.05 parts per million. The reason for this is the dissolved oxygen levels at input for the environmentally assisted fatigue calculation. Now we have provided this information to the NRC confirming that the dissolved oxygen level during power operation is less than 0.050 ppm. And we understand that the staff is ready to close this item, but they'll discuss that later today during their presentation.

MEMBER SHACK: Now have you got a decimal point in the wrong place here: 0.50 or 0.00?

MR. POLASKI: What was used in the calculation for why it was less than .05, in reality the dissolved oxygen is less than .005 or even less

than .0 -- it's not detectable because of the design of the system with hydrogen in the system. So --

MEMBER SHACK: In your fatigue analyses you relied very heavily on the number of design cycles and you've used those as the basis and then extrapolate those out. And typically that's very conservative. But have you actually done a history review to make sure that that's a conservative way to do it?

MR. POLASKI: Yes, we've reviewed the history. In the analysis we did, we did it initially using the design numbers of cycles and actually did it times one and a half to count 40 to 60 years. And for some locations multiplying by one and a half and doing the fatigue analysis you came out less than one. If it didn't but we could show we were less than one at the design numbers of cycles and we looked at the history, we don't expect to come anywhere close to the design numbers of cycles. And there was two locations in considering environmental effects where we couldn't stay less than one with the design number, so we used a history.

The history was projected from when the plant restarted after the six year shutdown going forward and then conservatively assumed more cycles

than that to show that we would be less than one for the environmentally assisted fatigue. We only needed to do that on two locations only for environmental effects.

MR. GALLAGHER: And, Dr. Shack, was your question more about the severity of the individual cycles? Because we also verified that.

MEMBER SHACK: Yes, that was --

MR. POLASKI: Right.

MR. GALLAGHER: We verified that the--

MEMBER SHACK: They truly were bounded?

MR. GALLAGHER: Yes, and it's something that's routinely monitored, you know, in the fatigue program. So that we not only did the numbers, but the severity.

MR. POLASKI: And we used all of the design cycles. We did not do any stress-based analysis.

CHAIR STETKAR: I had a question. Bill, are you --

MEMBER SHACK: Yes.

CHAIR STETKAR: Okay. The analyses that were done to project the number of cycles for those locations they're characterized as administrative limits right now. So they're somewhere between the

current 40 year design limit or/and the number of cycles that you would project given one and a half times 40. Is that correct? I mean, that's --

MR. POLASKI: No. Where we put the administrative limits on where those locations that on the original design number of cycles when we did the environmental assisted fatigue calculation would have been greater than one. We have imposed an administrative limit in our -- accounting program that is a number lower than the design number of cycles.

So, for example, and I don't know if this exact. For a particular cycle if the original design number was 200 and we'd found out that at 200 cycles we would have exceeded one in the CUF, but at 100 cycles we would have been less than one and we only projected based on our operating history we have 60 cycles at the end of plant life, we would put an administrative limit on less than a 100. Now don't go looking those numbers up in the --

CHAIR STETKAR: The numbers, no.

MR. POLASKI: I just used them for an example.

CHAIR STETKAR: I just wanted to know your general thought process because I was trying to work through --

MR. POLASKI: Yes.

CHAIR STETKAR: Okay.

MR. POLASKI: And the reason this works for TMI is that operating history has been so good, you know. Steve mentioned they go breaker to break one so you get one transient every cycle, it works out fairly well.

Any other questions on the confirmatory item? Okay.

Going on to slide 11.

I'd like to discuss two industry issues and how we handled those in the TMI license renewal application.

Slide 12.

The first of these deals with the calculation of environmentally-assisted fatigue. In preparing the TMI license renewal application we completed all of the TLAA calculations for environmentally-assisted fatigue to show we were less than one. And we just talked about that.

The other thing is the important point from an industry viewpoint is we used no simplified analysis methods in the calculations. We used a full set of stress-based information from the current licensing basis and did the complete calculations.

The second issue deals with the scoping for station blackout recovery path. In our application we included the high voltage circuit breaks in the TMI switchyard within the scope of the station blackout equipment in the application. And this meets the NRC expectations in the interim staff guidance on station blackout scoping.

Slide 13. This is a single line diagram of the TMI switchyard. The green depicts all of the equipment that's in scope of license renewal and includes the high voltage circuit breakers. The circuit breakers are the boxes. For example, in the lower left hand corner GB1-02 is one of those circuit breakers. So all of the ones in green are included in scope for the recovery path.

Any questions on that?

All right. Well, I'd like to now introduce Pat Bennett who is going to discuss the topic of corrosion on the reactor building liner.

MR. BENNETT: Good afternoon. My name is Pat Bennett and I'm the Mechanical Engineering Manager at TMI.

My topic is the reactor building liner and a corrosion issue that we first identified in the 1990s with our ASME Section 11 IWE program.

We monitored this condition through the IWE program and took corrective actions when we discovered corrosion by cleaning and recoating the effected liner areas. This presentation will describe how we're addressing the corrosion issue.

Next slide, please.

The issue is past borated water leakage and a degraded moisture barrier that resulted in corrosion behind and just above the moisture barrier. And we have fixed this.

The diagram to the left shows the bottom floor of the reactor building where it nears the wall liner. The area of interest is Detail A, which you can see to the right. You can see the carbon steel liner with the moisture barrier taking up the gap to the concrete floor slab. The combination of areas of degraded moisture barrier with episodes of borated water leakage were the cause of liner coating degradation and the resulting corrosion.

Next slide is a plan view of areas where we found the corrosion. This is a plan view of the lower level of the reactor building. We removed the moisture barrier during last outage in 2007 360 degrees around the reactor building and inspected above, at and below the moisture barrier. We found no

corrosion below the moisture barrier. The worst corrosion was behind the moisture barrier where we removed it.

Anywhere there was corrosion we measured liner wall thickness and these are the areas that you see on the diagram.

We evaluated the data to show that even the thinnest area was it within design requirements? And on the next slide I'll talk about specific actions we took to prevent recurrence and what we're doing about the corroded area.

Next slide, please.

MEMBER SIEBER: What was the moisture barrier made out of?

MR. BENNETT: The old moisture barrier was an RTDC liner

MEMBER SIEBER: Poured in?

MR. BENNETT: Laid in or poured in, yes.

MEMBER SIEBER: Below that's cork?

MR. BENNETT: The cork was a construction aid when we had the liner laid and we poured the concrete floor, that was there, yes.

MEMBER SIEBER: Water can go through that pretty easily?

MR. BENNETT: Yes. It would run down if it

were poured.

MEMBER SIEBER: Do you think it's unusual for the water to get through the moisture barrier which is supposed to be impervious to water and not go through the cork?

MR. BENNETT: No. What we found when we did the inspection when we pulled it out was that the moisture barrier hadn't fully separated, but had provided a gap where it had come apart from the wall. And the worst areas of corrosion was where we had moisture laying in that gap. And so again --

MEMBER SIEBER: So the barrier wasn't really broken all the way down?

MR. BENNETT: That's correct. And when we pulled it all out, we removed it all, we inspected down below that moisture barrier four to eight inches down in the moisture barrier gap.

MEMBER SIEBER: Okay.

MR. BENNETT: And there was no corrosion in that area.

MEMBER SIEBER: Okay. And so you recoated the liner at that point?

MR. BENNETT: We recoated the liner.

MEMBER SIEBER: After you measured?

MR. BENNETT: That's correct. Recoated

the liner and we also put in a brand new moisture barrier with an improved moisture barrier.

MEMBER SIEBER: Okay. That's also a poured?

MR. BENNETT: It's applied in. I don't know if you could say it's poured.

MEMBER SIEBER: Like a troweling?

MR. BENNETT: Yes, it's troweled in, I understand.

MEMBER SIEBER: Okay.

MR. BENNETT: Next slide. Thank you.

So in summary we identified corrosion in the 1990s and later on and monitored and inspected the liner in accordance with our IWE program.

The cause of the reactor building liner corrosion was borated water leakage and a degraded moisture barrier. And we fixed this.

Specifically the mitigation steps that we took are:

We corrected leakage and established the boric acid corrosion control program;

We inspected the entire moisture barrier liner perimeter in 2007;

We measured the wall thickness of the corroded liner areas in 2007 and ensured that the

existing liner meets design requirements;

We removed the old moisture barrier; cleaned, recoated the liner and installed the new improved moisture barrier in 2007, and;

We will inspect 100 percent of the moisture barrier every refueling outage starting in 2009.

Our liner repair plan is to weld repair any thinned area to establish all areas back to normal thickness prior to the period of extended operations. And that is scheduled in the fall of 2009 along with our plant integrated leak rate test.

MEMBER SIEBER: And how many feet of container or liner wall would that lineal feet would that be?

MR. BENNETT: Yes. What we found was we found 36 areas of corrosion when we went around the wall. The area was approximately 13 percent of the total perimeter --

MEMBER SIEBER: Which is?

MR. GALLAGHER: I think it's about 53 feet.

MR. BENNETT: About 53 feet of total area.

MEMBER SIEBER: Okay.

MR. GALLAGHER: And it's spread out,

spotted over areas.

MR. BENNETT: And again -- right.

MR. GALLAGHER: Not continuous.

MR. BENNETT: Right.

MEMBER SIEBER: Okay. So you have that all marked?

MR. BENNETT: It's all marked.

MEMBER SIEBER: So go in and dig out and do the weld repair?

MR. BENNETT: That's correct. And it's scheduled for this upcoming outage.

MEMBER SIEBER: Okay. How are you going to do the repair? Well, it's pretty close to the surface of the concrete, I take it, within a half an inch? That's so you can get welding rods and proper equipment in there.

MR. BENNETT: That's correct. Well in accordance with code.

MR. BARTON: Do steam generators fit through the existing opening or do you have to do anything with the opening?

MR. BENNETT: We're going to be cutting a hole in the reactor building during the outage to get the steam generators through.

MR. BARTON: So that'll be more welding on

the liner?

MR. BENNETT: That's correct.

MR. BARTON: Okay.

MR. BENNETT: Yes, more opportunities.

MR. GALLAGHER: And that's why we want to do that this outage because of the steam generator job and we're going to do the ingrade and egrade test, which is the post-installation test. And we'll take care of all this at the same time.

MEMBER SIEBER: When you do the weld repair of the liner, what kinds of action process will you do to assure that the weld has been satisfactorily laid in and that you've restored the thickness you want, I guess integrity? You're going to do -- you'll have to do a containment leak test, pressurized containment leak test after cutting a hole in the liner anyway?

MR. BENNETT: That's correct. And this lines with IRLT very well. We've got to schedule IRLT. We've got to do that for the steam generator job, and that lines up with that.

MR. GALLAGHER: To answer Mr. Sieber's question about --

MEMBER SIEBER: About how do you know--

MR. GALLAGHER: Do you want Gene to answer

that question?

MR. BENNETT: Yes. Gene Navratil is our ISI engineer.

MR. NAVRATIL: Gene Navratil, Exelon.

Our plans are to perform the welding with shielded metal arc welding. And after that we will perform a magnetic particle examination and UT examination to verify that we have the --

MEMBER SIEBER: So you have to prepare the surface where the welding has been done?

MR. NAVRATIL: That's correct. We will have to get rid of the rough edges.

MEMBER SIEBER: Well, yes, beads and whatever.

MR. NAVRATIL: Correct. So, yes. The process will be to remove the moisture barrier, any paint, clean up the surface for welding, perform NDE, do welding and then perform more NDE and verify restored thickness.

MEMBER SIEBER: Now the NDE that you do before the welding, what type will that be? You're not going to have a prepared surface, so UT probably is not applicable there. What are going to do for that one?

MR. NAVRATIL: If I understand the

question correctly, after we do the cleaning of the surface --

MEMBER SIEBER: And before the welding?

MR. NAVRATIL: Before the welding we would perform a magnetic particle examination to assure we've got no flaws.

MEMBER SIEBER: So you're looking for cracks?

MR. NAVRATIL: That's correct.

MEMBER SIEBER: Thank you.

MEMBER ABDEL-KHALIK: How is the liner attached to the concrete?

MR. BENNETT: Yes. There's metal embedments that come out from the concrete and the liner is attached to the concrete through that.

MEMBER SIEBER: Right.

MR. QUEEN: The liner was built first and then the concrete was poured behind the liner.

MR. BENNETT: Was poured, right.

MR. QUEEN: And as it was, the embedments were surrounded by the concrete and then encased in the concrete.

MEMBER SIEBER: They used a movable form to support containment?

MR. QUEEN: Yes, right. You build an

annular space essentially between the liner and the concrete, poured the concrete in lifts between there.

MEMBER SIEBER: Built mostly with rebar?

MR. QUEEN: That's correct.

MEMBER SIEBER: Okay.

MEMBER ABDEL-KHALIK: Is that annular gap between the liner and the concrete accessible for inspection?

MR. QUEEN: No, there is no gap. There was an annular gap built and then it was filled with concrete. That's how the frame was --

MR. BENNETT: Well, if you go back to the slide, Chris. That's pretty much it showed -- I guess what you see you'll see the concrete. I'll point to it here. That's pretty much --

MEMBER SIEBER: You got to take the bore to inspect it.

MR. BENNETT: Right. That's correct.

MEMBER ABDEL-KHALIK: But there was no buckling in that liner anywhere that would form a gap between the liner and the concrete.

MR. BENNETT: That is correct.

MEMBER SIEBER: It is not subatmospheric?

MR. BENNETT: That's correct.

MEMBER SIEBER: Every time you do an LRT

you push the liner back out --

MR. BENNETT: That's correct.

MEMBER SIEBER: -- and there's no force to pull it in.

MR. BENNETT: Any other questions?

Thank you.

MR. QUEEN: And next I'm going to talk about our issue on medium voltage cables and our underground vaults that contain those cables.

We have PMI of 8 total cable vaults that are in scope. The cables in those vaults supply power to our screen house, normally are energized to provide power to our river water pumps as well as our circ water pumphouse. So there were two sets of cables through the 8 vaults.

Although we've had no failures of our medium voltage cables we do inspect those cable vaults periodically and have found some of them full of water and have had to drain them.

The next couple of slides I'm going to describe what the vaults look like, how they're constructed, how we believe the water got in there and what our plans are to prevent water from getting in there in the future and to keep the cables dry going forward.

Go to the next slide, Chris.

MEMBER SIEBER: Let me back up to the liner just a moment.

MR. QUEEN: Sure.

MEMBER SIEBER: You had boric acid on the containment floor and other areas where boric acid, I'm sure -- I mean, it had to start from someplace. What other elements of the structure -- have been effected by boric acid leakage that on its way from wherever it leaked from down to the containment floor into the liner? Have you done an inspection to try to figure out where the problems were and what's been affected by it?

MR. BENNETT: Yes. This is Pat Bennett responding.

Yes, we have. The boric acid control program is in place to do just that. So anytime we see borated water in the building, even a drop now, we identify where it came from. We look for the path where it came from. And then we address it in the Corrective Action Program.

MEMBER SIEBER: Yes. My question is though from the boron that you found that caused the corrosion of the liner where did it come from?

MR. BENNETT: Oh. Okay. Yes. To answer

your question it came majorly from one episode of valve leakage that has been repaired and also from a seal plate leakage in the fuel transfer area that has also been repaired and welded. And so it does-- there's no opportunity for leakage.

MEMBER SIEBER: What valve was it that leaked, do you know?

MR. BENNETT: It was a chem-add valve, I believe. It is a --

MEMBER SIEBER: Small bore?

MR. BENNETT: It was a small valve.

MEMBER SIEBER: Okay.

MR. QUEEN: Sampling. Chem sampling valve that got cycled opened and closed each day to take chem samples.

MR. BENNETT: Right.

MR. QUEEN: Small valve, one inch.

MEMBER SIEBER: Standard packing?

MR. QUEEN: Standard packing, yes.

MEMBER SIEBER: Did the packing leak?

MR. QUEEN: It was a packing leak and the valve actually is located a floor above the location where the worst corrosion damage was. And it did run down along the floor, down the wall to the location. And the whole area was inspected and cleaned.

MEMBER SIEBER: Now if the plant is operating and you develop a leak like that one again, how will you know that it's leaking or will it leak until the end of the cycle and somebody goes in and there's all this boric acid all over the place?

MR. BENNETT: Well, certain leaks -- well, you know well we understand if we have leakage with leak rate --

MEMBER SIEBER: They can be pretty small.

MR. BENNETT: Right. Exactly.

MEMBER SIEBER: And once it's pretty small, it's hard to calculate.

MR. BENNETT: We have periodic inspections inside the reactor building and we've identified that.

MR. QUEEN: Right. We go in the reactor building monthly. And these areas are all accessible.

MEMBER SIEBER: In containment?

MR. QUEEN: In containment. These areas are accessible. You can see the liner.

MEMBER SIEBER: Are they on the outside of the shield wall?

MR. QUEEN: It is.

MEMBER SIEBER: Okay.

MR. QUEEN: And also our leak rate calculations would see the size of leak we had and

would flag us to go do additional inspections.

MEMBER SIEBER: Yes.

MR. BENNETT: One additional thing that we've done with the installation of the new moisture barrier is the old moisture barrier is laid flat on the floor.

MEMBER SIEBER: Flat?

MR. BENNETT: The new one is tapered. Starts up on the wall and curves down onto the floor. So it's --

MEMBER SIEBER: The floor is concrete with protective coating on top?

MR. BENNETT: That is correct.

MEMBER SIEBER: Right.

MR. BENNETT: That's correct.

MEMBER SIEBER: Okay. And what kinds of supports are on that -- that floor is flat, right?

MR. BENNETT: That's correct. It does tend to go towards drains, floor drains.

MEMBER SIEBER: Right.

MR. BENNETT: Slip to floor drains.

MEMBER SIEBER: So if you have leak, what kind of supports would the leak contact and do you have a program to look at those supports?

MR. BENNETT: We have a program do

inspections. So those inspections, those visual inspections would include anything in the path; supports, cable trays, anything.

MEMBER SIEBER: And how often do you do that? Every refueling?

MR. BENNETT: The inspections, what did we say, was --

MR. QUEEN: Inspections are performed each refueling outage for the entire containment building. Our boric acid corrosion control program requires that anytime you find a leak of any size that you inspect all the targets of the leak and you seek out and find those targets and inspect them and determine where the impact is.

So during our monthly inspections and walk-throughs of the reactor building if we were to find a leak, and these leaks would all be observable because they're outside the D ring or the shielded area, we would then -- it would kick the boric acid corrosion program into gear and we would then be required to look for targets and then clean the areas to ensure corrosion is stopped.

MEMBER SIEBER: Thank you

MR. QUEEN: Okay. This is Steve Queen, Operators Director.

We had started discussing the medium voltage cable issue. I completed the first slide where we talked about the number of cable vaults we have. We have eight vaults. And we had found that, although we have had no cable failures, we have found cases where we've had vaults full of water. And in the next two slides I'm going to describe how the vaults look and what we're doing to prevent water in the future.

CHAIR STETKAR: Before we flip to the next slide, Steve, the first bullet on this one says that it's repeated occurrence of rainwater accumulation. You're confident that it's rainwater, it's not bound water, not leakage from other sources?

MR. QUEEN: Well we're reasonably confident that it's rainwater. If there's a component of groundwater to it, we have not seen that. But our inspections going forward should identify that. I'll describe to you why that is on the next slide, if you can flip to the next slide.

CHAIR STETKAR: But you feel it's episodic driven rather than --

MR. QUEEN: Yes. This picture here shows a cross section of our vaults, of the typical cable vault. And I'll describe how the water gets in there

and I think that'll answer your question.

These vaults are -- the top of the vault is flush with the ground and the vaults are eight to 15 feet deep depending on the type of vault and the size of the vault.

With respect to groundwater, the water table is 5 to 15 feet below the bottom of the vault. So the bottom of the vault would be where you see the French drain area at the bottom in this picture; 5 to 15 feet below that is the groundwater level. So there would typically be no groundwater to intrude in that area. But what's happened over the years is in the manhole area at the top we've had -- the grading has changed over the years. People really weren't -- we weren't thinking about well where does this water go, what's the impact of that when the grading is changed as well as the gasketing material in the manhole had not been maintained. So that resulted in water coming in through the manhole.

That in combination with on the bottom of the vault area you'll notice a two inch pipe system which actually drains to a French drain. Those drains we found when we found these vaults full of water, we started an inspection program, put together a troubleshooting program. Went to inspect the vaults

and found that these French drains were full of silt and debris. Had not been inspected, there was no inspection program for the drains.

So as a result of that we have created an inspection program and a repair plan to go fix the drains so that the vaults will drain. And then secondly, to fix the manhole covers and the grading so that the water doesn't intrude into the vault.

MEMBER RYAN: Steve, one little question that will clarify for me. Where is the bottom of the vault relative to the water elevation of the river?

MR. QUEEN: The river typically is around 377, or 277 elevation. The bottom of the vault would be around 295, on average.

MEMBER RYAN: Oh, so you have a pretty good gradient from the bottom of the vault --

MR. QUEEN: Yes.

MEMBER RYAN: -- to the river?

MR. QUEEN: That's correct. The bottom of the vault is up here and the river is down here.

MEMBER RYAN: Okay.

MR. GALLAGHER: The river water level is 277, as Steve said.

MR. QUEEN: 277.

MR. GALLAGHER: And then the water table

level is typically 281.

MEMBER RYAN: Okay.

MR. GALLAGHER: And then like he said, 5 to 15 feet above that are the bottom of the vaults.

MEMBER RYAN: And I guess those are probably mean water level and mean table?

MR. QUEEN: Right. The island is -- under worst case flood conditions that we've had in many, many years the water level has gotten up to 299/300 elevation. That's really, really high. That's very atypical.

MEMBER RYAN: I mean, that would be an attention getting event --

MR. QUEEN: That would be.

MEMBER RYAN: -- for lots of reasons other than the manholes. But that's pretty convincing evidence that you really are dealing with the rain coming down rather than anything else coming in or up?

MR. QUEEN: Right. And the water table's well understood at TMI. We have -- because of the focus on tritium now in the industry we have a tremendous number of sampling wells drilled. And we understand the water table. We also understand the flow of groundwater at the island very well.

So probably the biggest indicator that

it's not significant groundwater intrusion is the fact that simply the water table is well below the bottom of the vault.

MEMBER RYAN: One thing I might add for the rest of the Committee, the Subcommittee's benefit is I did visit TMI was with the ACNW. And we did have a presentation from the geohydrologic consultant you had doing the groundwater monitoring for tritium. And I'd concur, you've got a very good team there and a good geohydrologic model of your site.

MR. BENNETT: Is 299 Agnes?

MR. QUEEN: I don't know what Agnes went to.

MR. GALLAGHER: Steve wasn't born then, so --

MR. BENNETT: Well, I'm really showing my age, right. Agnes was like the 100 year flood.

MR. QUEEN: I think Agnes actually came onto the island.

MR. BENNETT: Yes, but the dyke wasn't complete at that time, I think.

MR. QUEEN: And the ground level on the island is 305.

MR. GALLAGHER: Yes. Agnes was before plant operations, like '72/'73.

MR. BENNETT: Yes.

MR. QUEEN: So, any other questions on vault construction?

Okay. So two issues: The grading and the manholes making them leak-tight. And then the second issue is to make sure that the drainage system functions. And that's the plan going forward.

On the next slide this shows in bullet form essentially what I just talked through.

We will, our plan now starts this spring and completes in the summer. And that will be to install new lid gaskets, revise and improve the grading around the manways, and then most importantly get down in the vaults, clean out the French drain systems, test the French drain systems to ensure they work, we'll actually pour water into them to ensure they drain. And then our inspection frequency after that will be six month inspection frequency. We will increase or vary that frequency depending on what we find. If we find water in the vaults after we start these inspections and have completed the repairs, our troubleshooting plan would have us then do additional troubleshooting to determine the cause and repair the cause.

Our goal and our commitment is no

submerged cables.

MEMBER SIEBER: Okay. Now I'm sure you received Generic Letter 2007-01. The title of it is "Inaccessible or Underground Power Cable Failures That Disabled Accident Mitigation Systems or Cause Plant Transients." It's dated February 7th.

MR. QUEEN: Right.

MEMBER SIEBER: Okay. This is a generic issue with most plants.

MR. QUEEN: Right.

MEMBER SIEBER: And so it's not really a license renewal issue, it's an immediate issue. And I presume that you have responded to the Generic Letter?

MR. QUEEN: Yes, we have. We have --

MEMBER SIEBER: Give me an outline of your response.

MR. QUEEN: Would you like to do that, Deb?

MS. SPAMER: Deb Spamer, Exelon Nuclear.

The Exelon response to the Generic Letter identified a cable monitoring program that has a two phased approach. The first approach is to screen for failures. And then based on the types of failures you found, if you found any, to incorporate a testing program of the cables.

At TMI since there's been no failures, we're still in the screening phase of that implementation program. But we are doing megger testing of the cables.

MEMBER SIEBER: So right now you don't have a commitment to do cable testing?

MS. SPAMER: That's correct.

MR. GALLAGHER: Part of license renewal, Mr. Sieber, we're adding that to do commit to do cable testing --

MS. SPAMER: That's correct.

MR. GALLAGHER: -- and every ten years.

MEMBER SIEBER: Could the staff address that when they return?

CHAIR STETKAR: Just out of curiosity, do you have a regular inspection frequency for these manholes and vaults now? And I'm assuming you do, and what is it?

MR. QUEEN: Yes, we do. We inspect them every six months.

CHAIR STETKAR: Six months? Okay.

MR. QUEEN: And when we do, as I said, we found them full of water at times and that's what kicked off our troubleshooting to go find the issues we did and resolve them.

CHAIR STETKAR: But it's regular frequency, it isn't --

MR. QUEEN: It's a regular frequency inspection. And when we look, we'll pump the vaults down. And when we pumped them down, the water level came back; not immediately but over time it would come back. When you'd inspect the next time, the water was back. It didn't fill itself back up, but it came back over time.

CHAIR STETKAR: I mean, you don't have a program that says after, you know, two inches of rainfall you immediately go out and look at it.

MR. QUEEN: No, we do not. We do not.

MEMBER BONACA: Did you find that six months is adequate?

MR. QUEEN: No, not with the drain system fouled and the manways leaking it is not adequate. So that's why this spring we started the program to fix the drainage system as well as repair the manway so that the water does not get into the vault.

If we do inspect these vaults and find water in the future after we've taken these mitigating steps, then we will be taking additional mitigating steps to prevent the cables from being submerged. So it's not just here's what we're going to do and here's

the inspections we're doing. It's we will stop this from happening.

MEMBER BROWN: Your viewgraph states that you will adjust the frequency based on inspection results. And that's a little bit -- is it will it just get more frequent or would you move it from six months to a year or something like that? You just answered counter to that, you said no it's six months, fixed frequency come hell or high water.

MR. QUEEN: Yes, we will adjust the frequency based on what we find. If we find that the vaults are continuing to fill with water, we'll increase the frequency as well as change our mitigation strategies. If we find the vaults remain dry after we've mitigated them, then we would lengthen the frequency.

MEMBER BROWN: Okay. So you'll go both ways?

MR. QUEEN: Right, we'll go both ways.

MEMBER BROWN: I think that's a little bit counter to it's always six months. If you've got a baseline of six months, then you'll adjust based on results.

MR. QUEEN: That's correct.

MEMBER BROWN: Either higher or lower

frequency. Okay.

MR. QUEEN: That's correct.

MEMBER BROWN: And you're already in that program? You're not waiting the way I read part of the -- I think it was the inspection reports? It implied that it would be executed or implemented prior to entering the period for extended operation. But in fact, you're doing this now, is that correct?

MR. QUEEN: Yes. We already have been doing an inspection program and we're starting now in the spring with the mitigation program.

MEMBER BROWN: Okay.

MR. QUEEN: So the inspection program continues, it just becomes a commitment now and then the remediation becomes a commitment with respect to keeping the cables substantially dry.

MEMBER BROWN: Okay. I see.

MR. BARTON: In their Appendix A in commitments for license renewal, I noticed that a lot of the programs are ongoing now and the dates that they've provided for starting them are before license renewal date. And that's different than a lot of plants that say they're going to implement them on the date of license renewal. This plant's already implemented a lot of those programs.

CHAIR STETKAR: Yes. Well we've heard that in some of the other meetings it would be prior to going into a period of extended operation. But for the next five years it'll be where they are, so that's why I asked the question.

MR. QUEEN: Yes.

And the final bullet on here was the testing bullet we referred to, which is we will perform cable testing in accordance with the industry state-of-the-art methods, and then we'll follow those methods. And as they change over the years, we will revise our cable testing program to stay up with the industry.

CHAIR STETKAR: And I think I heard now that the type of testing that you do on the cables is just megger testing, is that correct?

MR. QUEEN: Megger testing, that's correct.

Any other questions on medium voltage cables?

MR. GALLAGHER: Okay. With that, we'll get into the next topic with Fred Polaski.

MR. POLASKI: Thanks, Mike. Fred Polaski. We will talk about a topic of Boral and spent fuel storage racks.

What I'd like to do is describe the phenomena that's of concern and interest right now. Discuss the TMI experience and then provide our analysis of the issue.

Slide 23.

The issue involves the formation of blisters on the Boral neutron absorber material and the potential for the blister to affect the assumptions used in the criticality analysis for the fuel storage racks.

The TMI fuel pool -- this is slide 24 -- there two types of high density fuel storage racks. The Region 1 racks have a water gap between the cells. And this water gap thermalizes neutrons and increases the effectiveness of the Boral absorber panels. Region 1 racks are used for new fuel prior to the fuel being inserted into the core and for temporary storage of once burned fuel when it's removed during outage, and for that fuel that has not yet met the burnup requirements to place it in the Region 2 racks.

The Region 2 racks do not have a water gap and they're not affected by this issue. But they're only used for discharged fuel that meets particular specific burnup requirements. Typically if its been in the reactor for two or three cycles.

There's about 1500 fuel storage locations at TMI. About 13 percent of those are Region 1 type racks. And currently, because we're between outages, those racks are empty.

Slide 25 shows a closer picture of the Region 1 racks. The way they are built, there are two plates of Boral absorber material between each fuel cell. The other way to describe it is there's a plate of the Boral on all four sides of each cell. And the plates are separated by a water gap that's sometimes called a flux trap.

Each plate of the Boral material consists of a core of aluminum and boron carbide powder with a cell of aluminum cladding on each side.

These plates only .081 inches thick. So they're very thin plates on each side.

On 26, these Boral plates are placed in a pocket of stainless steel that forms the cell box wall and then there's a sheathing area on the outside of it for physical protection. And the sheathing area is water filled because its vented by design.

I'll just point out, this drawing is not to scale. This is just a picture to show you what the issue is. And it's not really based on any specific data from particular blisters, but just to demonstrate

the issue.

The blisters are created if the aluminum corrodes, and corroding the aluminum results in aluminum oxide and hydrogen gas which would be trapped inside the cladding.

If the blister is such that it doesn't deform the stainless steel pocket or the sheathing, then the water gap between the two cells is unchanged and there's no affect on the neutron thermalization.

The water chemistry program for the fuel pool at TMI maintains boron concentration of the fuel pool above 2500 ppm. And at this concentration there will not be any corrosion or general corrosion of the aluminum. Any corrosion that would occur would be localized and it would occur in locations of surface imperfections where there were any contaminates from the manufacturing process. So it would be very localized and not general corrosion.

MR. BARTON: Well, these racks -- I'm sorry.

MEMBER SIEBER: Let me ask a question about that. You have boron carbide encapsulated between plates.

MR. POLASKI: Yes, sir.

MEMBER SIEBER: And the creation of the

blister is the plate is leaking somehow and you're getting water behind that. Does the boron carbide ever settle down inside the plate so that you end up with a gap where there is no --

MR. POLASKI: The way they are formed is that they are formed as one entity. So it's one compressed sandwich, if you will.

MEMBER SIEBER: Right.

MR. POLASKI: In a big sheet and then they're cut. So around the edges the boron carbide is exposed to water. And that's how the water can work its way through the carbide to get in between the two aluminum plates.

MEMBER SIEBER: You're not aware of any phenomenon where the boron carbide would be moved or displaced, or anything like that?

MR. POLASKI: No. No.

MEMBER SIEBER: Okay.

MR. BARTON: Are the racks you're showing here the same as in the Unit 2 fuel pool, or is this just Unit 1 racks?

MR. POLASKI: This is just Unit 1 racks.

MR. BARTON: But what are the racks -- you're going to use Unit 2 fuel racks sometime, right, for storage or whatever? No? Never going to use it?

MR. QUEEN: No. We've reracked our pool in Unit 1 so that --

MR. BARTON: Okay. So you don't have to use the racks in Unit 2? There aren't any racks in Unit 2 anymore, are there?

MR. QUEEN: No, Unit 2 --

MR. BARTON: No, that's right. Forget it. Forget it.

MR. POLASKI: Any other questions on that? Okay.

MR. BARTON: Forgot about that.

MR. POLASKI: All right. On slide 27 this depicts what could occur if the blisters are large enough and deforms a stainless steel pocket. The water gap dimension would then be reduced and this would affect the thermalization of neutrons.

Like I said before, the blister is caused by water intrusion into the boral plate. And what we expect is that the blister would remain full of water because the water is what causes the corrosion. So if the blister is full of water, then there's really no reduction in the amount of water there to attenuate the neutrons. So the concern would only be if the blister would be full of gas.

So when we do any analysis looking at this

we assume that the blister is dry, no water in it, for conservative assumptions in looking at the impact of this.

If we go on to slide 28, the experience at TMI. TMI installed high density Boral fuel racks in 1992. The surveillance coupons were installed at that time, and they are representative of Boral in the racks.

During the first five cycles the coupons were removed during every outage so that they were located and surrounded by newly offloaded fuel. And this was done to provide accelerated exposure to neutrons.

The analysis of the Boral coupons were performed in 1995, '97, '99, 2001 and 2008. No blistering was found during '95, '99 and '01. The largest blister that was found was in 2008. There was one blister found that was one inch in diameter and measured .058 inches of thickness or height. And it was determined to be water filled when it was inspected.

The other thing is that when they did these examinations when they removed the coupon from the coupon rack, the Boral coupons are enclosed in a stainless steel sheath similar to what's on the racks.

And those stainless steel sheaths were examined as part of the work and no issues were found with those. So there's no detected expansion of the stainless steel sheathing.

The coupons were tested and they showed no loss of boron in the Boral, no reduction in neutron absorption capacity in any of the coupons. And they did that using neutron attenuation tests.

And the results of this is consistent with findings that EPRI has found in the study they've done of this issue at several locations where there have been blistering in these Boral racks.

MEMBER BROWN: Why is the stainless steel prototypical of the actual aluminum cladded?

MR. POLASKI: Well, the stainless steel is typical of the configuration in the rack where the Boral coupon, which consists of the Boral and the two aluminum plates is in between the stainless steel sheathing and the --

MEMBER BROWN: All right. All right.

MR. POLASKI: So the coupon is the configuration -- the only difference between really the coupon is it's only like 7½ inches long where the Boral in the racks is 136 inches long. But they're made out of the same material, same process, just the

coupons are just smaller.

MEMBER BROWN: Got it.

MR. POLASKI: Okay. On slide 29, just to summarize where we are for TMI.

We have observed blisters. There have only been a very small number. You know, the largest one was one inch in diameter.

The effect of this blistering is bounded by uncertainties in the analysis. They're performed K_{eff} considering -- or the existing margins that are required for that.

MEMBER ABDEL-KHALIK: How are those criticality calculations performed?

MR. POLASKI: I'm going to ask Mr. Stu Getz to answer that question.

MR. GETZ: Stu Getz, Exelon.

The criticality evaluation, we did an evaluation based on the original evaluation that was done for the licensing report for when these racks were first installed. And what we determined from that is we used a manufacturing tolerance based on the cell. And that created an effect, simulated the fact that we would have a full sized blister, full width and full length over the entire size of the Boral panels on each Boral panel in the rack. And it

simulates it being non-water filled because it displaces the water in the flux trap.

And that effect when added as a penalty to the neutron multiplication factor that was obtained for the rack design gave us an increase because of the reduction in flux trap.

MEMBER ABDEL-KHALIK: So this didn't involve when you're doing a criticality calculation?

MR. GETZ: No, it did not.

MEMBER ABDEL-KHALIK: You just went back to--

MR. GETZ: It did not. This was an evaluation based on this grossly bounding full sized blister, 100 percent of every Boral panel. And we ended up with a K_{eff} effect that was well within the existing margin.

MR. POLASKI: And the last thing is that at TMI our Boral coupon surveillance program is going to continue throughout the period of extended operation.

And slide 30 to discuss aging management program with respect to the fuel storage racks and the Boral.

The first point, TMI water chemistry program manages loss of material due to general

corrosion of the aluminum cladding of the Boral.

And second, we will continue our Boral coupon surveillance program to continue throughout the period of extended operations. And we will perform evaluations to demonstrate that any effect on neutron multiplication factor is due to a postulated reduction water gap is within our design requirements. So we're going to continue the program we've been doing up until now. And any issues we find will be evaluated versus the design of the racks.

Any questions on the Boral and fuel racks?

CHAIR STETKAR: Yes. The discussion you've been having it relates strictly to the Region 1 rack configuration where indeed you do have the--

MEMBER SIEBER: The flux trap.

MR. POLASKI: Yes. The flux trap.

CHAIR STETKAR: What additional concerns are there? I'm assuming -- is the design of the Boral sheaths and the plates different in Region 2 or is exactly the same? And if it's the same, what other concerns are there in the Region 2 where --

MR. POLASKI: I'm going to let Stu--

CHAIR STETKAR: -- make it more mechanical interference, for example?

MR. POLASKI: Yes.

MR. GETZ: The design of the rack and the sheathing is slightly different in Region 2.

In Region 1, as you can see, if there were a blister that were to deform the sheathing, it wouldn't have a mechanical interference effect on the fuel that would be inserted into the box.

In Region 2, that's a deformation of the sheathing could have an affect on the amount of clearance that's available. But at the TMI Region 2 racks the sheathing is a thicker of material than the sheathing used on the Region 1 racks and it's more resistent to any kind of deformation that might results from a blister.

The interior dimension of the box is 9 by 9 and the fuel assemblies are 8½ by 8½. So there's currently about a quarter of an inch clearance all around the -- it's an inserted bundle.

MEMBER ABDEL-KHALIK: How thick is the water gap in --

MR. GETZ: 1.697 inches is the analyzed water gap dimension.

CHAIR STETKAR: Can you be more precise than that?

MR. GETZ: Approximately.

MEMBER ABDEL-KHALIK: If the gap was a lot

thinner than that, then I'm not sure the case assuming of no water would be the most conservative. If the thickness of this flux trap is a lot thinner then what you indicate --

MR. GETZ: You mean if it were to be reduced or, I'm not following. I'm sorry.

MEMBER ABDEL-KHALIK: I mean if the design were such that this gap is a lot thinner than that--

MR. GETZ: Oh, I see.

MEMBER ABDEL-KHALIK: -- then there are two competing effects. But in this case its thick enough--

MR. GETZ: Yes.

MEMBER ABDEL-KHALIK: -- that it is primarily a thermalization issue?

MR. GETZ: That's correct.

MR. POLASKI: The other aspect of this, too, that I think sort of puts it in perspective is that all of this is done assuming no borated water. Stu, am I correct? That's correct?

MR. GETZ: In these analyses.

MR. POLASKI: And with the borated -- the level of boron that we maintain in the fuel pool that the K_{eff} is reduced to .75, or some number like that, significantly less than .5. So we gain a whole lot of

margin.

You know, you don't credit the boron in the water for the analysis, but it is there and really almost makes this a mute point. But irrespective of that, we will continue the coupon surveillance program and then keep examining them, make sure they're working right.

Any other questions on that? Then that completes the --

MEMBER BROWN: I had a question.

CHAIR STETKAR: Are you done?

MR. GALLAGHER: Yes, Mr. Chairman, that concludes our prepared presentation, but we're open to any questions.

CHAIR STETKAR: And we'll probably have some.

Charlie?

MEMBER BROWN: I will go ahead and go ahead and go first.

Now under the fire protection area you all had an exception to the fire protection. I guess the GALL report says you're supposed to inspect those every six months and you all do a Halon in 18 and CO_2 in 24. So after some roundabouts and after reading six pages of discussion on the subject, see -- so I

want you to tell me whether I understand it and really did, is that the exception was accepted, if you convolute the language, although it appears that you now do inspections from what I could read in this thing, you're now doing the exception -- you're doing on the Halon system every six months, every three to six months. And you're now checking the storage tank level pressure for the carbon dioxide weekly.

So why -- since you're inspecting the Halon system every six months, why is that an exception still? I guess I didn't understand if you're really complying with the GALL periodicity.

MR. POLASKI: What we've committed to in the application was inspections every 18 months because the physical conditions of the equipment indicates that there's no reason to have to commit to every six months.

MEMBER BROWN: Okay. Well then if you go back and look at your last three tests, 2006 -- 18 months apart, 12/06, 6/05 and 2/04 you had three failures found or three problems found, whatever those were. One was a damaged grill I think or something like that. And then there was a fan motor failure and a fouled limit switch, which would have indicated the wrong position. It would not have indicated a valve, I

guess a fire water valve open. When it was really open, it would have still indicated closed.

So I guess my question is when you find multiple problems over that -- and that was just a three year period, that sounds like something's not working right or you're finding things every time you go look, which would imply to me that you need to look more frequently.

MR. QUEEN: Our approach --

MR. GALLAGHER: Let's let Stu answer that question. Stu?

MR. GETZ: Stu Getz of Exelon.

On those specific examples you're citing those were non-age related examples. One of them, I believe, was a mispositioned switch. One of them was a damaged grill.

MEMBER BROWN: Yes, the misadjusted switch. Yes.

MR. GETZ: Right. And I think your point on the other one is if we're doing examinations of the Halon supply every six months and that kind of thing, why are we taking exception. That exception was taken due to the GALL requirement of a full functional test every six months, which we do at 18 month intervals, I think, on the GALL.

MEMBER BROWN: Then I guess I didn't understand that particular point.

I understand these are not age related.

MR. GETZ: Okay.

MEMBER BROWN: But they're still problems that potentially compromise the operation of at least part of the fire protection system.

MR. GALLAGHER: Right. And those --

MEMBER BROWN: And you only do a functional test every 18 months, so they would be there and you wouldn't see them.

MR. GALLAGHER: Yes. There's other inspections that are going to be done; operator rounds, things like that where you identify deficiencies and capture them in the Corrective Action system. So, you know, that's how many things get identified in the plant and are constantly looked at.

What we were talking about specifically, like Stu was talking about with the exception, why was it an exception and why based on our own operating experience that the 18 month interval was sufficient versus the six month interval. And that's not to say, Mr. Brown, that you never find any problems in our other inspection programs, and that's why we continue to do those and capture them in the Corrective Action

system.

MEMBER BROWN: Well, it was implied that you found these during the functional tests in each of these things; that's when it was found during the 18 interval functional tests. Not by other inspections, by people walking around and seeing a fan that's not supposed to operate and not operating or a value that's not supposed to have been moved, not moved because it hasn't been moved and not indicating anything. So that's a little different than -- so that's why I asked the question because they weren't due to anything else. They were literally due to functional test performed, those were found as problems during the functional tests.

And from my background if I found problems during functional tests every time I did the test, then I kind of figured that I had to do it more frequently to make sure that I didn't have that failure already occur during the interval and then not know it.

MR. QUEEN: Our preventive maintenance program actually drives that. If we find enough repeat failures, we then will do evaluations on them and then change surveillance frequencies based on that to prevent reoccurrence so that the existing program

for preventive maintenance and testing drives that type of reinspection --

MEMBER BROWN: Well, does it actually operate the value? Or, I mean, you say "surveillance." I mean, surveillance to me means eyeballs looking at something, not necessarily turning a switch or initiating some action and having something start.

MR. QUEEN: Yes. The surveillance would identify the issues as well as operator rounds; multiple ways of identifying. And then the Corrective Action program identifies them and you bin them and say here's the failures I had, here's the number of components. This component had X number failures. And then our cause evaluations would look at that and say do we need to change the component, do we need to increase the frequency of inspection or change the maintenance practice.

MEMBER BROWN: So you're going to fog that one right by me. I guess I would probably defer to a couple of people on this Committee that are far more experienced in the commercial world than I am. I come out of a different -- the Naval nuclear world and that's a totally different perspective. I would still probably disagree with what you're telling me right

now because of just the time at which they were found and the fact that these were actual tests where they found as opposed to some other PM and I'm not familiar -- I don't know how those PMs or other things do, whether they actually these components or not.

MR. QUEEN: Yes. I guess --

MEMBER BROWN: So if nobody else is protesting, I'll probably take it to the point where I'll just wait and discuss it later with them. Okay.

Thank you.

That was it, John.

MR. BARTON: This miscellaneous yard structures and concrete foundations you've got listed in here, condensate storage tank and a BWST. And I looked for the aging management program for these tanks and the table for the BWST aging management program says but the program is external surface monitoring program. My question is how does that check the bottom of the tank or is there another program that does inspection at least one time or something of the tank bottom to assure there's no deterioration of tank bottom?

MR. GALLAGHER: Yes. Tank inspections. Mark, is that you?

MR. MILLER: Above ground, outdoor?

MR. GALLAGHER: The BWST.

MR. BARTON: Well, the BWST is outdoors, I believe.

MR. MILLER: Yes. I am not familiar with the --

CHAIR STETKAR: If you're going to say something, you have to come up to the mic.

MR. MILLER: I'm not familiar BWST.

CHAIR STETKAR: You still have to -- this is all on the public record and you have to officially tell us that.

MR. MILLER: I have to say I don't know?

Mark Miller, Exelon.

I don't know the answer to your question, off the top of my head.

MR. QUEEN: This is a question concerning the interior of the tank?

MR. BARTON: Yes. Just tank failures happen in this industry usually on the bottom of the tank. All right. Your tanks are both directly on concrete. And they've got a moisture barrier around the lip of the tank, I believe, right? How do you know that there's no deterioration of the tank bottom when the aging management program says what I'm going

to do is external surface monitoring? Well, that doesn't look at the bottom of the tank. So where is your program for, you know, at least a one time inspection of the bottom of the tank to assure there's no deterioration of the bottom of the tank over the period of operating life or over your operating period?

MR. QUEEN: Yes. I can talk to both to both of the tanks, our external tanks.

MR. BARTON: The borated water storage tank is the same way.

MR. QUEEN: Condensate storage tanks, we do have an external and an internal inspection program for condensate storage tanks. They are inspected. And that program looks at and examines the coatings in those tanks. You know we coat the tanks in an interval that's needed based on the inspections.

The borated water storage tank we had a one time internal inspection of that that went in with a robot, went down to the bottom, looked at the bottom of the tank as well as the side walls of the tank internally. It's a stainless steel tank. And we do external inspections of it, but it was a one time internal inspection.

MR. BARTON: And you've done that?

MR. QUEEN: We've done that. That's completed.

MR. BARTON: Okay. And you didn't find anything wrong?

MR. QUEEN: We did not find anything wrong.

MR. BARTON: Okay. Buried piping and tank inspection program. They performed several inspections of buried piping and you've already done that. At the time the application for the renewal was submitted the buried diesel generator fuel oil tank internal inspection program was not performed. Have you performed that and what were your results?

MR. QUEEN: The diesel tank, no. That's this outage. This upcoming outage. The underground--

MR. BARTON: You're going to do it this outage?

MR. QUEEN: That will be drained and inspected internally.

MR. BARTON: Okay. Thank you.

CHAIR STETKAR: There's some discussion about, I guess you have a common large -- I think it's called an area intake tunnel, but an air intake plenum that supplies air to the control building, the aux building and somewhere else in the plant. And

apparently there's been a history of water intrusion in there, that on an inspection report noted corrosion of -- if I can read my notes here -- conduits, cable boxes, conduit supports, degradation of fire protection piping.

What all is routed through that tunnel? I mean, obviously there are cables and pipes routed through that tunnel. What is in there and what are you doing to -- we talked about manways and trying to keep water out of cable manways. What sort of program do you have in place to address this issue, because it wasn't clear?

MR. BENNETT: This is Pat Bennett.

So we do have inspections of the air intake tunnel, periodic inspections of the air intake tunnel. And when we do notice that there are -- if there's a crack in the wall, if there's water coming through the crack, we have repaired that. So when we see a problem with water intrusion into the tunnel, it does get repaired. We have done that, we have done that in the past. And the past couple of years we have done work where we have seen water coming in and have sealed the cracks in the air intake tunnel.

MR. BARTON: Was that a routine inspection or a periodic inspection or --

MR. BENNETT: That's a routine inspection. Actually, we have inspections going down through there for fire service inspections. So there's a number of inspections that go through the air intake tunnel and they have the ability to identify issues.

CHAIR STETKAR: By the way, you've mentioned -- what I read specifically mentioned fire water piping. Are there any in scope cables that are routed through that tunnel?

MR. QUEEN: I think Ed knows that for sure. I think the answer is yes, but --

MS. SPAMER: Deb Spamer.

Yes, there have to be in scope cables in there.

MR. QUEEN: There have to be?

MS. SPAMER: Yes, there have to be. Well, the cables go out to the intake --

MR. GALLAGHER: The answer is there are.

CHAIR STETKAR: There are? Okay.

MS. SPAMER: Yes.

CHAIR STETKAR: Thanks.

MEMBER ABDEL-KHALIK: Back to the criticality calculations. What was the geometry for that limiting case? How was that geometry modified, that perturbed geometry that takes into account

variations and dimensions? What does that geometry look like?

MR. GETZ: Stu Getz, Exelon.

I think if I understand your question, you're asking the basis of our evaluation --

MEMBER ABDEL-KHALIK: No, I understand the baseline geometry.

MR. GETZ: I understand.

MEMBER ABDEL-KHALIK: What is the limiting geometry?

MR. GETZ: We have not done an analysis of, if I understand your question, how big a deformation --

MEMBER ABDEL-KHALIK: No, no, no. I understand exactly what you did.

MR. GETZ: All right.

MEMBER ABDEL-KHALIK: But what is the geometry for that limiting calculation? Is it exactly the same? You just changed the thickness of the water, is that it?

MR. GETZ: We reduced the -- effectively we reduced the flux trap/water gap by assuming the full size blister on every Boral panel.

MEMBER ABDEL-KHALIK: So you have a gas layer on both sides and that effectively changed the

thickness?

MR. GETZ: That's correct. If a blister were to form on the panel that was gas filled, it would effectively reduce the dimension of the water gap. And our bounding example assumed a blister that covers the entire surface.

MEMBER ABDEL-KHALIK: Yes, I understand.

MR. GETZ: Yes. And in so doing it decreases the dimension of the water gap.

MEMBER ABDEL-KHALIK: All right. Thank you.

MEMBER SHACK: One additional question. As I understand it you only have the Alloy 600 nickel alloy welds on the cold leg not on the hot leg, is that right?

MR. POLASKI: I'm going to ask Gene Navratil to answer that question.

MR. NAVRATIL: TMI is a B&W plant so we have nickel alloy locations in multiple areas.

If the question is do we have Alloy 600 welds that fall under the MRP program, that's only on the cold leg. The hot leg the Alloy 600 location has a pressurizer surge line connection coming at the hot leg because it's a carbon steel hot leg that has been overlaid in 2003. So that's the only large bore hot

leg temperature connection we have on the piping. And so that's been mitigated.

We are going to replace essentially the top half of the hot leg, which has small instrument connections for flow meters, vent lines, thermal welds. That whole upper half will eliminate the rest of the unmitigated Alloy 600 at hot leg temperature. And we will be --

MEMBER SHACK: But the attachment of the hot leg to the vessel has no nickel?

MR. NAVRATIL: No, that's correct. At the reactor vessel there are no connections. The Alloy 600 welds, the 82/182 welds are adjacent to the pump suction and discharge. Roughly two to three feet on each side of the pump. That is a transition. There is a forged stainless steel pipe that is welded to the pump. And that is stainless steel to stainless steel weld. And then about two to three feet away is a carbon steel to stainless steel weld that's connected with 82/182 material. So that's where those eight welds are located. Basically one weld on the suction and one weld on the discharge of each pump.

MEMBER SHACK: And the temperatures of those?

MR. NAVRATIL: Cold leg temperature --

help me?

MR. QUEEN: 555, five hundred and fifty-five degrees. Hot leg 600 degrees.

CHAIR STETKAR: Again, could you identify yourself, just so we have your name?

MR. NAVRATIL: Oh, excuse me. Gene Navratil, Exelon.

CHAIR STETKAR: Great. Thank you.

Any other members have any other questions? If not, thank you very much. It was a very good presentation.

And we will take a break until 3:15.

(Whereupon, at 3:00 p.m. a recess until 3:15 p.m.)

CHAIR STETKAR: Before we hear from the staff, I've been reminded that as I ran down the list of our participants here I overlooked John Barton, who is our consultant. And I didn't mean to do that, John. I'm sorry I slighted you. You certainly participate and we appreciate your input. But John Barton is here and he's our consultant.

And with that, I will turn it over to Jay Robinson, I guess, who will lead the staff's presentation.

MR. ROBINSON: Thank you, Mr. Chairman.

Brian, did you want to make any comments first?

MR. HOLIAN: Yes. This is Brian Holian, Director of License Renewal.

Just prior to, and for people who weren't here this morning, assisting Jay up there is Evelyn Gettys, the Project Manager for Susquehanna and we have Dr. Sam Li here as the side table, the Deputy in the Division of License Renewal.

I have just two other quick comments.

One, I just wanted to comment, Exelon commented on their years of experience and that during their presentation, which I think was very good. The Subcommittee also probably knows that we gain in the license renewal reviews when you have a fleet approach to license renewal. And, you know, they're well into their number of plants that they've reviewed and have learned from kind of the operating experience from our reviews. And I think that was evident in their presentation and even in our review as Jay will cover with the types of issues we found and how they responded.

There was one question of them earlier on. We'll have one of our staff members in particular talk about the Boral issue again on potential failure

mechanisms or not. We'll pick that up during the review.

That's all. Jay?

MR. ROBINSON: Thank you, Brian.

Good afternoon, Mr. Chairman, Subcommittee members. My name is Jay Robinson. I'm the Safety Project Manager for Three Mile Island license renewal. Today I will be discussing the safety evaluation report with open items.

Very briefly, this is the overview. I'll go into Section 2: The scoping and screen review. Following that Glenn Meyer will present information on the license renewal inspections. And then we'll discuss Section 3: Aging Management Program and review results. And Section 4: Time-Limited aging analyses.

Slide 3 is an overview which was information previously discussed by the applicant. I don't see any reason to repeat that here, so we'll move on to slide 4.

The Safety Evaluation Report was issued in March of 2009. There are no open items. There is one confirmatory item which concerns dissolved oxygen.

In total there were 123 requests for additional information issued and there are a total of

43 commitments.

Slide 5 just provides details on the audits that were conducted. You can see we did a scoping and screening methodology audit, followed by our aging management program audit and followed by our regional license renewal inspections.

Begin on Section 2, first looking at Section 2.1 the scoping and screening methodology. And based on its review of the application and the additional information submitted as a result of our requests for additional information, the staff determined that the applicant's methodology is consistent with the requirements of the applicable regulations.

In addition to that in Section 2.2 for the plant-level scoping results based on the staff's review of the application and the RAIs, the staff concluded that the applicant identified the systems and structures that are within the scope of license renewal per the applicable regulations.

MR. BARTON: That was after the 120 RAIs on scoping and screening?

MR. ROBINSON: That is correct. There weren't a 120 on scoping and screening.

MR. BARTON: I'm exaggerating. I thought

they could have done a better job of marking up boundary drawings and stuff. I noticed there was an awful lot of RAIs on the scoping drawing.

MR. ROBINSON: On Section 2?

MR. BARTON: Yes. Right.

MR. ROBINSON: Yes.

Moving on to Section 2:3 the scoping and screening results for the mechanical systems. In that section the staff identified nine systems that required the applicant to revise the application and add additional components into scope.

Examples of the component types omitted included:

The fuel tank for the standby diesel engine for the emergency diesel generator air start system air compressor. That's the reason why we didn't say "fuel tank" because it was involved. I wanted to make sure everyone understood the correct one;

Lube oil lines, and the intake bar racks. And these items were subsequently added to scope and subject to an aging management review.

And for Section 2.3 based on its review of the application and the additional information submitted as the result of the staff's RAIs, the staff

concluded that the applicant identified the mechanical system components within the scope of license renewal per the regulations and also subject to an aging management review.

For Section 2.4 the scoping and screening results for structures. The staff identified one component that required the applicant to revise their application and add the component into scope. This was a structural steel platform associated with the dyke and flood control system. This was located on the inboard side of the dyke and it supported the sluice gate and the associated operate.

And also with Section 2.4 based on a review of the application and the additional information submitted by the applicant, the staff concluded that there were no omissions of structures or structural components from the scope of license renewal per the regulations. And also no omissions from aging management review per the appropriate regulations.

Section 2.5 which is the scoping and screening results for the electrical systems and commodity groups. The station blackout recovery path, which was discussed in this section, includes the complete circuits within the scope of license renewal.

This includes the complete circuits between the onsite circuits and up to and including the substation which includes the switchyard circuits and associated controls within the scope of license renewal.

I think in the applicant's presentation they showed you a drawing of the switchyard which depicts that.

In Section 2.5, again based on its review of the application and the requests for additional information, the staff concluded that there were no omissions of electrical systems and commodity groups from the scope of license renewal per the appropriate regulations and no omissions from aging management review.

The overall conclusion for Section 2.6 conclusion for scoping and screening. Based on its reviews of the application, the onsite audit results and additional information submitted as a result of the RAIs, the staff concluded that the applicant's scoping and screening methodology meets the requirements of 10 CFR 54.4 and 54.21(a)(1). And also that the applicant adequately identified those systems, structures and components within the scope of license renewal in accordance with 10 CFR 54.4(a) and those structures and components subject to an AMR in

accordance with 10 CFR 54.21(a)(1).

And that concludes Section 2. Were there any questions on Section 2?

CHAIR STETKAR: I would just like to mention, I was pretty impressed with the thoroughness that the staff did on this one on the scoping and screening. You did a good job, I think, in terms of searching --

MR. BARTON: As evidenced by the number of RAIs.

CHAIR STETKAR: Well, and the types of questions that were asked.

MR. BARTON: Yes, good questions.

CHAIR STETKAR: It's one of the better jobs that I think we've seen. So I think you deserve credit for that.

MR. ROBINSON: Well, thank you. Thank you very much. I wasn't the Project Manager at the time. Billy Rogers over there, Billy did that.

With that, I'll turn it over to Glenn Meyer who will discuss the inspection results.

MR. MEYER: Good afternoon, Chairman Stetkar, ACRS members.

I was on the regional inspection team, I was not the team leader. Michael Modes was the team

leader, but we had a conflict this week between ACRS presentations today and the inspection at Nine Mile during the outage of their commitment fulfillment. So we chose to split that up.

I will say in the scoping area, since it's been brought up, it's interesting to compare Susquehanna this morning and TMI this afternoon. Susquehanna this morning was done quite a while ago because of the delay. And what we've kind of evolved to is I joined the scoping audit and look at things from a regional standpoint, and also the reviewer in addition to Billy and his continuing effort, the reviewer is no longer contracted and so he's had an in-house chance to get experienced and see the kinds of issue that come up. So I think those factors have tended to help the scoping.

And so I'll proceed.

Our inspection had two main objectives of looking at the scoping of non-safety system structures and components. We also sampled 19 of the aging management programs to evaluate their thoroughness.

Regarding scoping, we concluded that scoping of non-safety systems, structures and components was generally accurate and they had used an acceptable approach. We did review structural and

spatial interactions as a part of that.

In the aging management programs we did pursue looking at the program procedures, the records, we did walkdowns of systems in the plant, we evaluated the operating experience that had gone into the proposed activities for the aging management programs.

The concerns regarding aging management programs were minimal. There were a few issues that were raised. None of them rose to the level of needing any changes to the application and they addressed the concerns onsite within the program's procedures.

We did have one item of interest. The team leader choose to pursue the operating experience approach that Exelon used in the TMI application where they did rely on some period. Typically they'll look at a five year period. And they did use the EPRI mechanical tools for three years of that five year period. So spent some time to look at how its organized and capturing the information applicable to TMI. And sampled some of the information both at TMI and in the tools to make sure that it was thorough. Our inspection concluded that the approach was a sound one and had captured the right information.

CHAIR STETKAR: Can I ask you a little bit about that? I personally am a big fan in terms of looking back at plant-specific operating experience. I think you learn an awful lot from that. And when I say "you," generically you, the applicant and the staff.

This is the first, I believe, license renewal certainly that I've been involved in, and I've been on the Committee only for a year and a half now, where there seems to be reliance on that EPRI tools document as a surrogate for a detailed enumeration of actual plant-specific operating experience.

As you mentioned, the applicant I believe searched their plant-specific records, if I'm not incorrect, from the period of January 1, 2005 through November 30. 2006. So about two years. And the remaining three years of the five year period that they examined they referred back to the EPRI report.

I'm not familiar with that EPRI report. So if someone could educate me quickly. Does that EPRI report contain detailed information such that it's an enumeration of events that have occurred at each plant identified by plant or is it simply a summary of industry experience?

MR. MEYER: I'm not certain I'm the right

person to talk to the EPRI tools --

CHAIR STETKAR: Okay. Okay.

MR. MEYER: -- since this was our first experience at looking at them in detail.

CHAIR STETKAR: I'll turn to then someone from Exelon who may have some --

MR. POLASKI: Yes. Fred Polaski with Exelon.

Before I answer that question about mechanical tools, let me clarify a little bit on how we do the operating experience review at TMI. And there's really two parts to that.

One is you do a review of plant operating experience to determine if there's any aging effects that are unique to your plant that hadn't previously been identified. That was the review that we used the mechanical tools to do.

The other part of the review we do is an operating experience review of the programs and how well the programs have worked. When we review the programs we looked back at the entire plant history. All right. We didn't limit that to five years. I mean, so there's information we looked at, you know, talking to plant program monitors going back beyond the five years and identified any issues with

programs.

So just to be clear about the two different parts and how we did that.

Now the part on the aging effects, what the mechanical tools is its a document that was initially generated over 12 years ago, 15 years ago by the B&W Owners Group License Renewal Committee to support the B&W plants. And this for Oconee and the other B&W plants when they were early in the license renewal process. And the reason for it was to identify combinations for non-Class 1 equipment, materials, environments and aging effects that needed to be managed long term.

Subsequent to the B&W Owners Group having developed it, the BWR owners Group, the Boiling Water Reactor Owners Group, the Westinghouse Owners Group bought into that, had it updated and expanded to include BWR environments, Westinghouse operating experience. And once we had developed that altogether, we turned it over to EPRI to maintain it. It gets periodically updated every so many years.

The update to that does a review of the industry operating experience by looking at significant events, NRC generic correspondence, information from INPO, NEI information on issues that

have gone on and updating that document with broad-based industry operating experience with respect to materials, environments, aging effects and what they are, what needs to be addressed is with managed aging going forward.

So our position at TMI was that because that had been updated through, I guess December of 2005 you mentioned or January 2005 that would have included any aging effects that would have been identified -- new aging effects identified at TMI.

You know, I've been working this for a while and a lot of discussions the way the GALL is developed and the way the rule is we look at aging effects. So anytime if we found a new aging effect for material environment combination, I'm sure that's going to make a lot of news, it's going to be very evident and will raise itself to a high level very quickly because there'll be some new phenomena going on that nobody had known about before.

So we believe that the search we did using the mechanical tools and then our own detailed search after the last update on the mechanical tools is more than adequate to identify any aging effects that would have been unique to TMI that hadn't been previously identified.

MR. MEYER: Another thing that the tools do is compare their guidance to the GALL and whether its consistent so that it focuses--

CHAIR STETKAR: I understand that as a generic industry type of comparison and clearinghouse. I guess I'm still not -- again, I'm personally a big proponent of looking at individual events, things that occurred at your plant and understanding how they relate to your plant rather than it being diluted through an industry reporting and summarizing type of process.

What types of -- I mean because I'm not familiar with this process and I don't want to take too much time but I do want to understand it because of my emphasis on operating experience. How do you report things and what things do you report? What type of screening process do you use when you suddenly decide that you're going to send something to EPRI to be included within this tools document?

MR. POLASKI: In the operating experience process at TMI, any of the Exelon plants and I suspect I could say this for any plant in the industry, we all have our own internal operating experience where we review events at the plant. We also review external experience that raises itself to the level it's of

industry interest, and we review that.

From an internal viewpoint if we would have an event at a plant where it was -- the review of that indicated that we had some failure of a piece of equipment due to some new phenomena, that's going to raise itself to a very high level. It will be of very strong interest. It very well may have to be reported on a Part 21 and have generic implications.

And so I think what we're dealing with here is, for example, in boiling water reactors because I'm a lot more familiar with them than I am with pressurized water reactors, but we know that in boiling water reactors recirc piping and stainless steel is subject to intergranular stress corrosion cracking. That's a very common phenomena, we understand that. Carbon steel is not.

If we find that some plant would discover that carbon steel was subject and has undergone IGSCC, I'm sure that that kind of information, because this is a new thing for carbon steel that nobody had previously identified, would very quickly raise itself to a very high level. And I truly expect that the NRC generic correspondence is going to come out very quickly on something like that. And that's the level we're talking about when we're looking at aging

effects that we need to deal with for license renewal.

And in the review, you know, more than 50 percent of the plants nobody has found any new aging effects yet.

CHAIR STETKAR: Well, except we have seen experience where plants have looked back at their own operating experience and identified something unique to their plant. It could be water -- you know, we talk about water intrusion, we talk about corrosion of specific piping under specific soil conditions and things like that. They don't rise to the surface of the large industry generic issues that you're talking about --

MR. POLASKI: Yes. Yes.

CHAIR STETKAR: -- and yet that it could be something for that particular site that may dictate -- and we've seen examples of this in our Committee already; that may dictate the need for a unique program for that site. It's a site-driven program. And the only way that it's identified is to look carefully at the site operating experience and say, "Ah, we indeed have identified a problem here and we need to address that with either a slightly different program or an enhancement to an existing program to address our condition."

Those are my concerns. I am interested, but I'm not concerned certainly with the large things that certainly come up to the industry's attention.

MR. POLASKI: I agree with your concern in that area, but that's the kinds of issues that the plant internal operating experience ongoing review process that occurs on a routine basis would identify at a plant.

I mean, it's things I've seen is where you get some unique situation where you've got -- the plant ends up with an environment/material combination that isn't typical.

CHAIR STETKAR: Yes.

MR. POLASKI: So if you get into some condition like that, that will get you into the programs that you maybe otherwise wouldn't have gotten into because of some unique combination of material environments it's not typical.

I think Mike wants to something, too.

MR. GALLAGHER: Right. This is Mike Gallagher of Exelon.

And Mr. Stetkar, I think that's exactly what Fred started out at the beginning, is we actually did do a detailed operating review for programs for just the point you're pointing out. Is there anything

unique at TMI that we need to address, and let's factor it into the program. And in fact we have a plant-specific program, there's one plant-specific program.

What we were trying to do as far as in this AMR review is really, you know, we have to address all the aging effects that are in the GALL and then we have identify are there any other ones out there. So we used this industry tool and then we did our own search. So we think we have all that basis covered.

CHAIR STETKAR: What I'm trying to do is to gain some confidence about the last part of that statement "all the bases covered."

MR. GALLAGHER: Yes.

CHAIR STETKAR: Because the examples of the operating experience that are documented in the LRA and the SER, unless there's specific examples that were provided in response to a request for additional information, all of those plant-specific examples date from January 1, 2001 to November of 2006 which has led me to somewhat uneasiness about that completeness of the surge back through five to ten years, at least, of operating experience to understand that that had someone been accounted for the process.

MR. GALLAGHER: Okay.

MEMBER BONACA: I had a question on this, if I could. In the programs you have an attribute which is operating experience.

MR. POLASKI: Yes.

MEMBER BONACA: That attribute is very plant-specific, right?

MR. POLASKI: Yes. The OE -- well, there's two parts to the operating experience for programs. One is industry operating experience and the other is plant-specific. So we do review industry operating experience with programs and plant-specific operating experience with the programs.

MR. HOLIAN: This is Brian Holian, Division License Renewal. I'd just like to comment on additional comment on operating experience.

I hope part of it might just be in the write up at TMI. I mean, I presume that that's the case. Just a month ago we had Indian Point in here for a review. And ever since the Inspector General finding they particularly looked at operating experience and the usefulness of that and criticized us for maybe not going into as much depth on independent looks to their condition reporting database. So we have been concentrating on that.

We've added additional internal guidance for our reviewers to go back. And on Indian Point in particular they picked up some of those containment concrete items that this Subcommittee looked at, which was specific to their plant and we looked at for is this a potential? Is this a new aging effect as Exelon stated?

I think the Boral issue that we're talking about is a potential new aging effect that's out there. And, you know, it has besides just the blister, maybe a possibility for gaps in the substance itself. It hasn't maybe exhibited itself yet, but other substances have that are used in spent fuel pool.

So our staff is to look at that, not to look necessarily just at the last five years or whatever. And so I would propose that that's more of a documentation issue. We've been trying to concentrate on that and we'll try to make sure that's flushed out in the SERs.

CHAIR STETKAR: Yes. Thanks.

MR. MEYER: It may be a statement of the obvious, but the review of program effectiveness for reviews of operating experience is not applied to the new program on the theory that --

CHAIR STETKAR: Well, and that's indeed one of the reasons -- not the program effectiveness, but indeed some of the scope of the new -- especially the new programs or the identification of a need of a plant-specific new program in many cases can arise from that review of the operating experience.

The effectiveness of the existing programs, as the applicant mentioned, in many cases in fact is tracked through the existing program process.

So, thanks.

MR. MEYER: Okay. I think we're up to inspection conclusions. The inspection concluded that the scoping of non-safety systems, structures and components and the aging management programs are acceptable. We concluded that the inspection results support a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained during the period of extended operations.

Also, I'd like to touch briefly on current performance at Three Mile Island. It's currently in the licensee response column of the action matrix, the lowest level of regulatory oversight. And that position or categorization is based on all the inspection findings being green and all the

performance indicators currently being green.

And I think we have a slide. So that shows the performance indicators.

And that ends my presentation.

MR. ROBINSON: Okay. Thanks, Glenn.

Now it's Jay Robinson from the Division of License Renewal.

With that we'll move on to Section 3, the aging management review results. Slide 16 just goes through the applicable sections of the SER.

We'll move to slide 17 to discuss the aging management programs. There were 38 aging management programs, seven were new, 31 were existing, 21 were consistent with the GALL report, nine of those had enhancements. There was plant-specific program. Eleven had exceptions. And then six had both enhancements and exceptions.

MEMBER SIEBER: Could you characterize the exceptions? You know, is it because the licensee chose a later version of things or for what reasons?

MR. ROBINSON: For the most part, yes, as the applicant stated earlier. Different revisions of EPRI reports. I think one that comes to mind might be the water chemistry guidelines the subsequent revision came out whereas the GALL cites another revision, for

the most part.

MEMBER SIEBER: None that we could consider downgrades, right?

MR. ROBINSON: Pardon me?

MEMBER SIEBER: No exception was taken that we would consider as a downgrade?

MR. ROBINSON: Not that I'm aware of.

MEMBER SIEBER: Less frequent surveillance, less corrective action?

MR. ROBINSON: No.

MEMBER SIEBER: Everything is enhanced?

MR. ROBINSON: Yes, that's to my understanding.

MR. MEYER: The fuel tank sampling that I mentioned earlier.

MEMBER SIEBER: That's buried? Right.

MR. MEYER: So they made the point that it made little sense to dig it up to look at it. And so I think they substituted a UT or there was -- they met the requirement in another way.

CHAIR STETKAR: The Halon and CO_2 --

MEMBER SIEBER: Okay.

MR. MEYER: Longer, you know, longer inspection intervals, but that's pretty standard that everybody takes.

MEMBER SIEBER: Okay.

MR. ROBINSON: Okay. We'll move on to slide 18, which is the groundwater sampling results. Groundwater sampling for pH, chloride and sulfate concentrations will be performed every five years during the period of extended operation. They did conduct previous samples in 2007 and 2005. And those samples indicated that the groundwater is considered nonaggressive for steel embedded in concrete.

I'll touch a little bit on an issue that the staff discovered concerning the reactor head closure studs. During the audit the staff identified the use of the Dow Corning G-N lubricate for reactor head closure studs. This is composed of moly disulfide which may promote stress corrosion cracking. The staff issued an RAI on this and the applicant agreed to enhance the program by selecting an alternate stable lubricant that is compatible with the material and the environment prior to the period of extended operation. That is in commitment number 3. They revised commitment 3.

MEMBER ABDEL-KHALIK: Has this lubricant been used from day one?

MR. ROBINSON: I'm going to ask the technical staff to answer that. He's coming.

MR. SUN: Robert Sun, Division of License Renewal.

As far as I know, I believe that lubricant has been used from day one. What happened was TMI had initially stated that their program was consistent with the GALL for this program element of preventive actions. And while we were at the MP audit, you know, we looked at a material spec sheet for the lubricant and that turned out to include the 14 percent moly disulfide, which led to the RAI. And we did look closely at the operating experience. They didn't have any evidence of cracking from their inspections which they do every outage. And it didn't commit to the enhancement.

MEMBER ABDEL-KHALIK: I think that was my next questions. These studs have been examined for cracks, I guess, and they're examined every outage?

MR. MEYER: Every outage.

MEMBER ABDEL-KHALIK: Thank you.

MR. ROBINSON: Thanks, Robert.

And based on the applicant's response for the staff's request for additional information, the staff found that acceptable and that resolved their concern.

MEMBER SHACK: I thought moly disulfide

was gone a long time ago.

MR. ROBINSON: I guess not.

MR. BARTON: I thought people gave up on that a long time ago.

MEMBER BONACA: Maybe they had a bit supply of it.

MEMBER SHACK: That's right. A lifetime supply.

MEMBER SIEBER: Don't sell your stock.

MR. ROBINSON: Move on? Okay. To the next slide, which covers the reactor building liner, which the applicant discussed in detail during their presentation.

We looked at the operating experience and that indicated corrosion at several locations due to moisture intrusion through the moisture barrier. The staff issued an RAI and the applicant committed to restore the liner to its nominal plate thickness by weld repair for the previously identified corroded areas where the thickness of the base metal is reduced by more than 10 percent of the nominal plate thickness. And they were committed to do that prior to the period of extended operation.

And also the applicant performed an engineering evaluation and determined that the

intended function of the liner is currently being maintained.

The staff found the applicant's proposed corrective actions acceptable regarding the liner.

Now the next slide discusses the inaccessible medium voltage cables not subject to 10 CFR 50.49 environmental qualification requirements. The operating experience showed that inaccessible medium voltage cables and several manholes experienced water submergence for more than a few days.

During the staff's AMP audit the staff found cables submerged underwater in two manholes. We issued an RAI requesting the applicant provide a certification of the cables ability to be submerged or an action plan to preclude cable degradation. And the applicant is going to adjust their frequency of inspections based on the inspection results in order to keep the cables from significant moisture.

And water in the manholes is a generic current plant issue that's being addressed during the current period of operation through the reactor oversight process.

With regards to the aging management programs, based on the staff's audit and review and the additional information that the applicant

submitted as a result of the RAIs, the staff concluded that the effects of aging will be managed so that intended functions will maintained during the period of extended operations per 10 CFR 54.21(a)(3).

The next slide discusses reduction of neutron-absorbing capacity and loss of material due to general corrosion. The applicant indicated that the water chemistry program manages the loss of material due to general corrosion. And that the Boral surveillance program manages the reduction of neutron-absorbing capacity.

The staff did issue an RAI on this and the applicant did respond. In this particular case we're able to put that information in the SER that we issued in March. They do have a commitment to continue the Boral test coupon surveillance through the period of extended operation.

The staff did conclude that the programs adequately managed loss of material from general corrosion from Boral and also managed the reduction of neutron-absorption capacity aging effect for the period of extended operation.

And with that, I'd like to introduce Matt Yoder who will talk more specifically to Boral.

MEMBER ABDEL-KHALIK: Before we get to

that, can we go back to slide 20.

MR. ROBINSON: Yes. Slide 20?

MEMBER ABDEL-KHALIK: I guess the indication is that all the corrosion is above the surface of the concrete. Is there any indication of corrosion below that level in inaccessible areas?

MR. ROBINSON: Not that I'm aware of, but I'll have the technical staff who reviewed that area answer your question.

MR. XI: Xuhan Xi, structural engineer of NRR.

During the audit we reviewed operating experience. The corrosion we found is at 281 level, most is, and the other is at 279 a six inch at that depth. Yes. So basically it's behind the moisture barrier.

MEMBER ABDEL-KHALIK: Who would you know that there's no corrosion in the cork region?

MEMBER SIEBER: Take it out.

MR. ROBINSON: My understanding is that the applicant inspected, I think, four to eight inches below --

MEMBER SIEBER: Right. That's right.

MR. ROBINSON: -- the seal and which involved the cork area.

MEMBER ABDEL-KHALIK: So that's the extent of the applicant's knowledge as far as the state of the liner; it goes four to six inches below the surface of the concrete?

MEMBER SIEBER: The corrosion --

MEMBER ABDEL-KHALIK: Is that correct?

MR. BENNETT: This is Pat Bennett from Exelon.

Sir, the corrosion, as I stated earlier, was found behind the moisture barrier and above the moisture barrier. And we did a full visual inspection when we removed the moisture barrier and found no corrosion below the moisture barrier.

MEMBER SIEBER: But the moisture barrier is one inch, right?

MR. BENNETT: That's correct.

MEMBER SIEBER: So it's from one inch below the surface to maybe a half an inch above, is that right?

MR. BENNETT: That's correct, yes.

MEMBER SIEBER: But not in the cork area, and you dug that out?

MR. BENNETT: As I said, we inspected four to eight inches below the moisture barrier elevation and there was no corrosion.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. GALLAGHER: Sorry, one thing while there was a slight pause in the action.

This is Mike Gallagher, Exelon.

We did have one little correction on the reactor vessel stud inspection that you had asked a little bit ago. So, Steve, could you do that?

MR. QUEEN: Yes. Steve Queen, Exelon.

Just for completeness we inspect the studs each outage as a maintenance visual. We don't do NDE on them each outage. And the maintenance visual looks for boric acid, corrosion, any moisture and we don't find that.

We also do NDE. We'll do UT on the studs. Divide them into three groupings over ten years. So about every outage to every other outage they get a UT, a third of them. So I didn't want to imply that we did NDE on them every outage. And we have not found any cracking and we haven't found any evidence during the visuals of any damage to the studs. But the visuals are maintenance visuals, they're not NDE VT1s, VT2s. They're not VT1s.

MR. GALLAGHER: And Mike Gallagher.

And it's primarily due to in addition to this material you have to have moisture. So there's -

- we have been successful at TMI in keeping the moisture out of that area.

MR. YODER: Okay. Matt Yoder from NRR.

I want to provide some of the staff perspectives on Boral as well as other neutrons or materials. And I'll keep this quick, but I think this is going to beneficial for the ACRS because it's a topic you're going to hear over and over again.

We had a presentation by the applicant today about blistering of Boral and how that could impact the flux trap region in the Region 1 of the spent fuel pool. And while the staff thinks that was an excellent presentation and is fully aligned with that, there is another potential degradation mechanism that the licensee's program also covers that wasn't discussed today, and it's also a concern for the staff. And that would be the settlement out or the dissolution of that material within the panels. So --

MEMBER SIEBER: That was my question.

MR. YODER: That was why I wanted to address it.

WE have not seen this in Boral in date. We have seen this with boroflex, of carburon and with some of the other materials.

So the staff position is regardless of the

material whether it's Boral where we don't have history to date or it's one of the other materials where we do have some operating experience on, we want licensees to have surveillance programs in place such that if we do hit some time where Boral starts to degrade, we'll catch it early on and we'll be well aware of what's going on.

So there's an interim staff guidance being prepared on all neutron-absorbing materials. And I just basically wanted to throw it out to clarify what heard earlier, I guess.

MEMBER SIEBER: Let me follow up with a question just to clarify my memory. It seems to me Boral, that has boron, elemental boron in it. If it captures a neutron, you get helium and something else, which I forget what it is. Is it the helium gas that causes the blister?

MR. YODER: My understanding is that the blisters in Boral are caused by water intrusion and then the corrosion of the aluminum material itself.

MEMBER SIEBER: Okay. As opposed to helium?

MR. YODER: Correct.

MEMBER SIEBER: Okay.

MR. ROBINSON: Thank you.

MEMBER ABDEL-KHALIK: How far above a fuel bundle does the Boral plate extend?

MR. GALLAGHER: Stu, can you answer that question.

MR. GETZ: Stu Getz, Exelon.

The Boral panels in the racks are 136 inches long.

MEMBER ABDEL-KHALIK: But they're the shorter than the bundle?

MR. GETZ: They are shorter than the bundles by --

MEMBER ABDEL-KHALIK: Six inches?

MR. GETZ: -- approximately six inches. That's correct.

MEMBER ABDEL-KHALIK: Okay.

MR. ROBINSON: Okay. We'll move on to the conclusion for Section 3: Aging management review results.

Based on its review of the application and the additional information submitted by the applicant, the staff concluded that aging effects will be managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation.

And that concludes Section 3. We'll move

on to Section 4: Time-Limited aging analysis.

The first slide just shows the various sections of Section 4. We're not going to go into each one. We'll just go into some of the more notable areas.

The first one is Section 4.2: Neutron embrittlement of the reactor vessel and internals. I'm going to discuss the Charpy upper shell energy for beltline plates and forgings. Also for beltline welds and also pressurized thermal shock limits.

In this next slide here you can limiting belt -- let's see here. The limiting material is the lower shell plate C3251-1, which has a 52 EFPY Charpy USE of 64, which is greater than the acceptance criteria of 50.

Of the limiting beltline weld, which is the limiting matter, is the upper shelf to lower shelf circumferential weld WF-25 which has a 52 EFPY USE at ¼T of less than 50 and required equivalent margin analysis.

And the results of the EMA were acceptable.

Move on to the pressurized thermal shock limits.

The referenced temperature pressurized

thermal shock units for the limiting beltline material and the limiting beltline weld are below the established screening criteria of 270 degrees and 300 degrees respectively found in the regulations.

Move on to Section 4.3: Metal fatigue of piping and components.

A 60-year fatigue analysis were performed for the applicable high fatigue locations of NUREG/CF-6260. The initial analysis indicated that four locations had a CUF greater 1.0. And they were:

The reactor vessel lower head instrument nozzle penetration weld;

Reactor vessel outlet nozzle;

The pressurizer surge line elbow, and;

The makeup/high pressure injection nozzle.

Further evaluation was performed by the applicant and the final results indicated that the locations have an EAF-adjusted CUF of less than 1.0

And TMI will manage fatigue of Class 1 components using the metal fatigue of reactor coolant pressure boundary aging management program.

Move on to Section 4.3.2, which includes confirmatory item 4.3.2-1. This is similar to the item we discussed this morning for Susquehanna.

The Fen values were calculated based on

assumed dissolved oxygen concentration data 0.05 ppm. And the staff questioned whether that number was bounding. The applicant indicated that it was bounding and their historical DO levels were less than .005. And they also indicated that they had administrative controls in place to maintain data before this level.

The applicant initially submitted data from 1985 to current and then the confirmatory item was mainly because we were looking for data from '74 to '79. And they did provide that information. They pulled up all the old logs and confirmed what they maintained during that time period. And the staff agreed that that was acceptable and we're in the process of closing out that confirmatory item.

Move on to section 4.9, which is the conclusion for the TLAAs.

Based on the staff's review the application and the additional information submitted from the RAIs, the staff concluded that the applicant provided an adequate list of TLAAs and that they will remain valid for the period of extended operation. That they have been projected to the end of the period of extended operation. And that the aging effects will be managed for the period of extended operation.

CHAIR STETKAR: Jay, question. One of the items in your list was environmental qualifications of electrical equipment. And I noticed that, again, going back to the theme of operating experience that there had been at least one or two situations where the temperature in an area that contains the main feedwater reg valve and the feedwater bypass reg valve was out of spec. The ventilation system apparently had problems and temperature got to about 154 degree, if I read correctly, which is higher than it's supposed to be in the area but apparently less than the qualification temperature.

I was curious whether there had been more events because these events that were cited were within that January 1st through November 2006 period that I mentioned. I was curious whether there had been other events in that area as part one.

The other part is that the applicant apparently did an evaluation that said well these are normally de-energized valves and the temperature didn't exceed the qualification limits, and therefore everything's okay. And I was curious about the claim that these are normally de-energized valves since the main feed reg valves are usually not normally de-energized.

So I guess we have a little bit of time here and I'd like to understand a little bit more about that particular location and whether:

1: Has there been any other history of heating up that location because of ventilation problems? Because it's normally a pretty warm location, the main feedlines go through there.

And whether or not the fact that the applicant -- I'm not personally familiar with environmental qualification process. So whether the fact that the applicant said that these are normally de-energized components has any impact on the determination of the effects of that temperature?

You may not be able to answer that question. I'm kind of curious whether the --

MR. ROBINSON: The technical staff is going to assist me on that one.

MR. NGUYEN: This is Duc Nguyen. I am the auditor.

When we talk about environment qualification, we do the pre-age shock cable. What we mean we pre-age, that mean we cut the cable at the shorter of period of time with the high temperature to qualify that cable for the 40 year.

And this particular cable, I believe, is

they are qualified for very high temperature. 200 something degrees Fahrenheit.

The normal environment for that is 150, I believe. And looking at the operating experience we found that the environment is higher than the typical environment. But this still below the environmental qualification.

So that mean that this cable still qualifies for the 40 year and it does not effect the qualified life. When the end of the 40 year life, then you have to replace the cable or requalify the cable. So we determined that.

And this is only a short period of time because the ventilation equipment, they're not working for the period of time, a shutdown hour. So the question then we say why doesn't it effect. And the answer is they are qualified for 250 degrees and if we are go below -- above 150 degrees for a few hours or a few days, it doesn't effect the qualification. Therefore, the staff concludes that it doesn't effect the qualify of the cable.

CHAIR STETKAR: Okay. I'll ask the applicant. Has there been a history of problems with ventilation in this area? I recognize the fact the temperature may be -- I think the statement was made

the nominal temperature, according to your EQ file ambient temperature for the area is 110 degrees Fahrenheit and that the -- apparently the cables are qualified for 198 degrees for a 40 year life, and we're talking about getting 20 more years out of them.

MR. GALLAGHER: Yes. Mr. Stetkar, I'll have Steve Queen that question.

This is Mike Gallagher, Exelon.

Steve?

MR. QUEEN: Yes. Steve Queen, Exelon.

The area is warm, 110 degrees typically. We occasionally, not frequently, will have a ventilation problem that we'll have to repair but it's not typical that we'll temperatures above 150 degrees in that area, as was the case stated here.

So the answer is no significant number of failures of the ventilation system in the area. We have not exceeded the EQ value when we have had ventilation issues.

The energization issue is really around solenoids, I believe. So there's solenoids attached to the main reg valves, and that's -- you're correct. The reg valves aren't energized, they're air operated valves

CHAIR STETKAR: Well, but they're normally

controlling so --

MR. QUEEN: That's correct.

CHAIR STETKAR: They energized and de-energized.

MR. QUEEN: Right.

CHAIR STETKAR: They're not normally de-energized.

MR. QUEEN: That's correct.

CHAIR STETKAR: They're energized for a reasonable fraction of time when they have to move.

All right. Thank you. I was looking more in terms of the history of the operating experience, again because this particular event was highlighted because it happened during that January 1, 2000 to November 2006 and I was curious if you went back another five or ten years whether there was a history of losses of ventilation.

MR. QUEEN: No, we haven't had any significant loss of ventilation in those areas.

CHAIR STETKAR: Thank you.

MR. ROBINSON: Thank you.

I think we're on the lost slide here which states the staff's conclusion regarding the application for TMI-1 will be provided in the final Safety Evaluation Report which is scheduled to be

issued in July of 2009.

And that concludes my presentation.

CHAIR STETKAR: Any other questions from--

MR. BARTON: Glenn, were you on this team, or you weren't the team leader but you were on the team?

MR. MEYER: On the team, not the team leader.

MR. BARTON: Okay. In your inspection report you noted as a result of general walk-through -- I'm coming back at you -- inspection of the site there were signs of degradation in various structures visited. Inspection was focused on structural issues, identified some weaknesses in the structural of aging management program.

Well, you know, the applicant subsequently changed their program, amended its program to take care of those issues.

Now, did you guys look at anything else on the structures and do you have any comment on what the rest of the site looked like?

MR. MEYER: Structures. He does a walk-through of various structures, looking at conditions, making sure that things they've identified previously are evaluated, tracked and trended.

I think that TMI had some issues that were in their system. It might not have been, say, as new as Susquehanna that we talked about this morning. But I don't think it was outside the bounds of acceptable by any means.

CHAIR STETKAR: Okay.

MR. MEYER: And as to the rest of the plant I really couldn't make any comments. There was nothing noteworthy that we would say.

CHAIR STETKAR: All right. Okay.

MEMBER ABDEL-KHALIK: Have you taken any systems and looked at it in detail like you did with Susquehanna?

MR. MEYER: In this inspection we chose not to do a system review. The operating experience was, in a sense, a substitute for that. It's another way of looking at the objectives. It varies.

CHAIR STETKAR: Anybody else?

Thank you very much.

And we find ourselves about 20 minutes ahead of our schedule. What I'd like to do now is open up the bridge line so that Ms. Aamodt has an opportunity to make her statement that she's requested.

So if we can -- are you there?

MS. AAMODT: I'm here.

CHAIR STETKAR: Excellent. You are open and we can hear you.

MS. AAMODT: Oh, good.

CHAIR STETKAR: And you have the floor.

MS. AAMODT: If there's some time if you can't hear me. I feel like I'm so far away from you that you can't hear me. But I know things work better with telephones than shouting.

CHAIR STETKAR: So you have the floor.

MS. AAMODT: Well, I thank you very much, Chairman Stetkar, for providing me this opportunity to express our concerns.

I am an experimental psychologist. My husband is an engineer and physicist. And we worked as research scientists as members of the Technical Staff of the Bell Telephone Laboratories in Murray Hill, New Jersey before moving to Pennsylvania in 1963. We lived in Chester County, 45 minutes southeast of TMI on a 300 acre site which we developed into a working farm using organic horticulture.

We never left the consulting business and other things we were doing, but we did that on the side. We had lots of energy at that time.

In September of 1979 at the invitation of

the NRC, our family became a party in the NRC hearing to decide whether or not TMI Unit 1 should be relicensed following the accident.

And after participating for nearly five years, we first heard that residents who had symptoms attributed to psychological stress lived in certain neighborhoods. Now that belied a psychological origin and thus, I went out and conducted a door-to-door survey of three of those neighborhoods and uncovered a rate of death from cancer which was ten times the expected the rate for those townships.

The TMI Public Health Fund expressed interest in my study, came to my home, verified the data with their Pennsylvania Department of Health, the population numbers and wrote to me to say this was indeed an excess of cancer deaths with a clear relationship to the TMI accident. Drs. Cobb, Cochran, Morgan, Abrahamson and Woodwell were most intimately involved with our work and they prevailed in getting the Health Fund to underwrite a follow up by researchers with Columbia University.

They found a post-accident rate of cancer incidence for the ten mile area in excess of what as expected. Particularly outstanding was the incidence of lung cancer, but the cause was not attributed to

the accident because the researchers were informed that no member of the public received a radiation dose in excess of 1000 mrems. This study was under review and approval of the nuclear insurers.

Now in 1997, Dr. Steve Wing determined that the rise in cancer incidence that was shown by the Columbia Study among 60 civil divisions in the ten mile area correlated almost perfectly with the relative distribution of radiation, which was made by Dr. Beyea who developed that distribution with the utility's consultant.

The relationship between increased cancer rates across increasing levels of dose was most consistent for lung cancer.

Dr. Wing's work was published in *Environmental Health Perspectives* IN 1997.

Now the lynch pin is that in 1994 and '94, we obtained blood samples from residents who complained of symptoms which were erythema, difficulty breathing,, nausea, tingling over skin, metallic taste and smell at the time of the accident and then a loss of hair and graying of their hair. And one women experienced a complete loss of her kidney.

There were 29 others who had lung collapses and other kinds of problems that were so

outstanding.

There were 28 people that we tested ranging in age from 16 to about 60 years and the samples were analyzed by scientists at the Russian Academy of Sciences. They found universal severe immune system suppression, increased levels of stable and unstable chromosome aberration and a frequency of translocations obtained with the FISH method from which they estimated average absorbed dose for the examined person of approximately 100 rems. This work was published by the Scientific Council of Radiobiology of the Russian Academy of Sciences in March 1996.

Now earlier, within a few years after the accident, the NRC commissioned a study to investigate alleged psychological systems experienced by residents. And they found that all subject had significant lymphocyte depression. Repeated testing of these subjects five years later showed that immune system depression persisted and the researcher proposed that the cause was radiation exposure which the students had in common since a control group living in Delaware and highly stressed by identification of a toxic waste dump in their neighborhood did not exhibit lymphocyte depression.

The threshold dose to cause immunosuppression is 50 rems.

This was an NRC study which was funded by the NRC and it was principally accomplished by Dr. Andrew Baum of the Uniformed Services University.

The number of residents who were severely exposed to ionized radiation is, of course, not limited to the approximately 450 residents of the three neighborhoods west of TMI which I surveyed or the several dozen subjects studied by the Russian Academy of Sciences or the two dozen subjects considered by Dr. Baum. Many other people complained of symptoms through various entities from the time of the accident. Records of the identities of these people are held by a Census-taker for the CDC Pennsylvania Department of Health Survey of the five mile area residents, a state representative who later became Mayor of Harrisburg, several area doctors, and most notably scientists who, upon finishing their graduate courses at Columbia University, spent several years immediately following the accident gathering this information. These young scientists provided their findings to the Three Mile Island Alert organization and to the NRC, and then published in journals of Kyoto University where one of the

researches is on the faculty.

The surviving members of this cohort of exposed persons could be identified and tested for the presence of translocations by the FISH method. I would suggest using the services of the Russian Academy of Sciences who have this vast experience in conducting and interpreting these kinds of tests.

Now the most recent and alarming information is that people who were living within 5 miles of TMI have been dying over the 20 years following the accident at a significantly higher rate than the population of the three adjacent counties. This is indicating the effects of continued immune system suppression on this population of approximately 30,000 people.

This is a study done at the University of Pittsburgh by Dr. Evelyn Talbot funded by the Health Fund. There were significant elevations in male deaths from cancer of the respiratory system, of the bronchus trachea and lung from a nonmalignant respiratory disease. And also elevations in all malignant neoplasm breast cancers in men and leukemia and from all external causes.

For females there were significant elevations in deaths from non-malignant respiratory

disease, cancer of the nervous system, breast cancer, leukemia and lymphatic and hematopoietic tissue, other lymphopoietic cancer and cancer from all external causes.

Ten children under 18 years of age died due to cancers, which included cancers of the bronchus/lung, acute leukemia, Hodgkin's disease, lymphoma, ovary and brain.

This cohort was identified by CDC and PDoH for the specific purpose of determining the environmental status of the people living close to the reactor.

Our view is re-licensing of the TMI reactor will expose already compromised people to an unnecessary exposure to radioactivity which we believe in contrary to the mandate of the NRC to protect human health and safety. The NRC has admitted the release of radioactivity to the environment in excess of established limits as will result from the replacement of the steam generators.

Many of these families have lived i the TMI area for generations and are not able to move away. I spoke with one such family on this recent past 30th anniversary of the accident. They are presently coping with the recovery of a daughter from

the removal of a tumor the size of an orange that are "the mother died of a heart attack after unexplained suffering for many years of undiagnosed and leg problems." The father still develops rashes when he spends time outside. These are people who have symptoms of exposure during the TMI accident. And I interviewed them in 1984.

Now because the steam generators tubes have been leaking these many years, people have been receiving more exposures. I do not see where this impact on a community has been evaluated. These releases are of particulates of as many as 240 different kinds of radionuclides according to Dr. Kocker. The risk is similar to the NRC's analysis of exposure to radon. I am now quoting from your draft statement on pages 8-27 and 28: "The particulates are inhaled" and this your analysis of radon, I believe I said that. "The particulates are inhaled and remain lodged in the lungs, causing continued exposure." This relevant exposure of TMI residents from inhalation -- this is my own words now -- of radioactive particulars has never been acknowledge or considered. This is a chronic dose that is still occurring in these people.

Your report admits that recent monitoring

of leafy vegetation, soils and sediment, surface water and fish show concentration of radiological contaminants. The REMP program found strontium 90 in more than one half of the small number of milk samples tested in nearly all food products. The pre-operational period which you use as the baseline included the accident and cleanup period. So I find that an improper comparison. And assumptions of residual fallout due to weapons testing at this time is not a credible explanation.

I think that what you are saying is that TMI area residents have experienced continual internal exposure to radioactive particulates from fallout due to weapons testing and from nuclear power generation.

We believe that the law and conscience require, your conscience, requires additional assessment of the health status of the population. Before any decision is made to replace the steam generators and re-license Unit 1, we are requesting that the study of 5 mile residents be updated to the present time. It stopped with 1999. And the data be made available to independent researchers for a consensus and a follow-up with FISH tests for translocations in the blood of families suffering medical problems. In the meantime, Unit 1 should be

shutdown. It would be the right thing for you to do.

As an alternative to re-licensing Unit 1, the NRC acknowledges that "Conventional Hydroelectric Power" could play a role but the NRC staff did not evaluate hydropower as an alternative to license renewal. I would strongly suggest that the NRC do that.

Thank you very much.

CHAIR STETKAR: Ms. Aamodt, thank you very much for your comments. And we will certainly consider them during our Subcommittee deliberations and during full Committee.

And, again, thank you very much for your input.

We will now close the bridge line so you can continue to listen in until the meeting is adjourned, but we won't be able to hear you anymore.

So thank you again.

MS. AAMODT: Thank you. Bye-bye.

CHAIR STETKAR: Bye.

Let's see. Staff is finished.

What I'd like to do before we close the meeting is just to make sure that there are no further questions, either for the staff or for the applicant, among any of our members. Anybody have anything?

Nothing?

With that, we'll close the meeting.

(Whereupon, at 4:27 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Wedensday, April 1, 2009

Work Order No.: NRC-2756 Pages 1-140

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Three Mile Island Generating Station - Unit 1 License Renewal Application

ACRS Subcommittee Presentation

April 1, 2009.

Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Three Mile Island Nuclear Station, Unit - 1 (TMI-1)

Safety Evaluation Report (SER) with Open Items

April 1, 2009

Jay E. Robinson, Project Manager
Office of Nuclear Reactor Regulation

Exelon Nuclear

Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Program and Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- LRA Submitted by letter dated January 8, 2008
- Babcock & Wilcox (B & W) Pressurized Water Reactor (PWR), carbon steel-lined concrete (DRYAMB) containment
- 2568 MWth, 852 MWe
- Operating License DPR-050 expires April 19, 2014
- Located 10 miles southeast of Harrisburg, PA
- Unit 2 Shutdown in safe storage mode of Post Defueling Monitored Storage (PDMS)

Overview

- Safety Evaluation Report issued March, 2009
- 0 Open Items
- 1 Confirmatory Item
- 123 RAIs issued
- 43 Commitments

Overview

- Scoping and Screening Methodology Audit
  - May 19, 2008 – May 22, 2008
- Aging Management Program (AMP) Audit
  - July 14, 2008 – July 16, 2008
  - July 28, 2008 – August 1, 2008
- Regional License Renewal Inspection
  - November 17, 2008 – November 21, 2008
  - December 08, 2008 – December 12, 2008

- Section 2.1 - Scoping and Screening Methodology
  - Based on its review of the LRA and additional information submitted as a result of Requests for Additional Information (RAIs), the staff determined that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1)
- Section 2.2 - Plant-Level Scoping Results
  - Based on its review of the LRA and additional information submitted as the result of an RAI, the staff concluded the applicant identified the systems and structures within the scope of license renewal per 10 CFR 54.4(a)

- Section 2.3 – Scoping and Screening Results: Mechanical Systems
  - The staff identified nine systems that required the applicant to revise their application to add additional components into scope
    - Examples of component types omitted included: Fuel tank for the standby diesel engine for the emergency diesel generator air start system air compressor, lube oil lines, and intake bar racks, which were subsequently added to scope and subject to an AMR
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant identified the mechanical system components within the scope of license renewal per 10 CFR 54.4(a) and subject to an aging management review per 10 CFR 54.21(a)(1)

- Section 2.4 – Scoping and Screening Results: Structures
  - The staff identified one component that required the applicant to revise their application to add the component into scope
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that there were no omissions of structures or structural components from scope of license renewal per 10 CFR 54.4(a), and no omissions from AMR per 10 CFR 54.21(a)(1)

- Section 2.5 – Scoping and Screening Results: Electrical Systems/Commodity Groups
  - Station blackout recovery path includes the complete circuits within the scope of license renewal
  - Based on its review of the LRA and additional information submitted as the result of an RAI, the staff concluded that there were no omissions of electrical systems/commodity groups from scope of license renewal per 10 CFR 54.4(a), and no omissions from AMR per 10 CFR 54.21(a)(1)

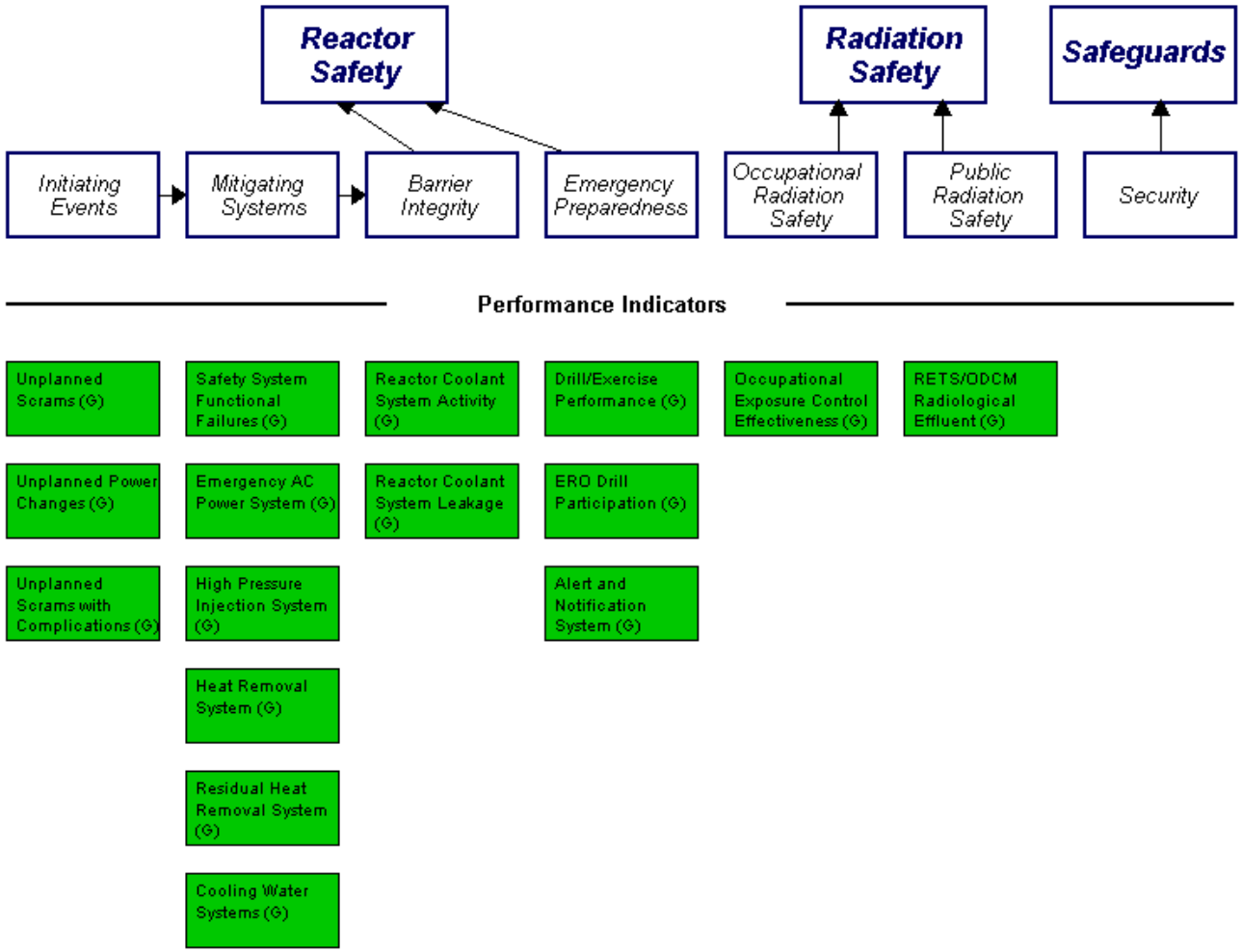
- Section 2.6 – Conclusion for Scoping and Screening
  - Based on its review of the LRA, the onsite audit results, and additional information submitted as the result of RAIs, the staff concluded that:
    - The applicant's scoping and screening methodology meets the requirements of 10 CFR 54.4 and 54.21(a)(1), and
    - That the applicant adequately identified those SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a), and those SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1)

- Inspection Objectives
  - Scoping of Non-Safety SSCs
  - 19 Aging Management Programs (AMPs)
- Scoping
  - Scoping of non-safety SSCs – generally accurate and acceptable
  - Structural and spatial interactions reviewed

- Aging Management Programs
  - Reviewed AMP program procedures and records
  - Walked down systems in plant
  - Evaluated operating experience
  - Concerns – Minimal; addressed onsite

- Item of Interest
  - Operating Experience Approach
- Inspection Conclusions
  - Scoping of non-safety SSCs and aging management programs are acceptable
  - Inspection results support a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained.

- Current Performance
  - Licensee Response Column of Action Matrix
  - All Findings – Green
  - All Performance Indicators (PIs) - Green



Last Modified: January 30, 2009

- Section 3.0 – Aging Management Programs
- Section 3.1 – Reactor Coolant System
- Section 3.2 – Engineered Safety Features
- Section 3.3 – Auxiliary Systems
- Section 3.4 – Steam and Power Conversion System
- Section 3.5 – Containments, Structures and Component Supports
- Section 3.6 – Electrical Commodity Group

- Section 3.0.3 – Aging Management Programs (AMPs)
  - 38 – AMPs
    - 7 New Programs
    - 31 Existing Programs
  - 21 consistent with GALL Report
    - 9 with enhancements
    - 1 plant specific
  - 11 with exceptions
  - 6 with both enhancements and exceptions

Groundwater Sampling

- Groundwater sampling for pH, chloride, and sulfate concentrations will be performed every 5 years during the period of extended operation.
- TMI-1 Groundwater is non-aggressive

	Acceptance Criteria	2007	2005 (Three Samples taken)
pH	**>5.5**	**7.4**	**7.8/7.8/7.7**
Chlorides	**<500 ppm**	**58 ppm**	**57.3/42.4/65.5 ppm**
Sulfates	**<1500 ppm**	**27 ppm**	**44.2/53.3/48.0 ppm**

Reactor Head Closure Studs

- During AMP audit, staff identified use of Dow Corning G-N lubricant for reactor head closure studs
  - Composed of 14% Molybdenum Disulfide
  - Molybdenum Disulfide may promote stress corrosion cracking
- Staff issued RAI and applicant agreed to enhance program by selecting an alternate stable lubricant that is compatible with the fastener material and the environment prior to the period of extended operation
- Staff found applicant's response to the RAI acceptable and their concern resolved

Reactor Building Liner

- Staff identified that operating experience indicated corrosion at several locations due to moisture intrusion through the moisture barrier
- Staff issued RAI and applicant committed to restore the liner to its nominal plate thickness by weld repair for previously identified corroded areas where thickness of the base metal is reduced by more than 10% of the nominal plate thickness, prior to the period of extended operation
- Applicant performed engineering evaluation and determined the intended function of the liner is currently being maintained
- Based on its review, the staff found the applicant's proposed corrective actions acceptable

Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

- TMI-1 operating experience shows that inaccessible medium-voltage cables in several manholes experienced water submergence for more than a few days
- During AMP audit staff found cables submerged under water in two manholes
- Staff issued RAI for submergence certification for cables or action plan to preclude cable degradation
- Applicant will adjust frequency of inspections based on inspection results in order to keep cables from significant moisture
- Water in manholes is a generic, current operating plant issue that is being addressed during the current period of operation through the reactor oversight process in accordance with the requirements of 10 CFR Part 50

- Section 3.0.3 – Aging Management Programs (AMPs)
  - Based on it's audit and review and additional information submitted as the result of RAIs, the staff concluded that the effects of aging will be managed so that intended function(s) will be maintained during the period of extended operation, per 10 CFR 54.21(a)(3)

Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

- Water Chemistry Program
  - Loss of Material due to General Corrosion
- Boral Surveillance Program
  - Reduction of Neutron-Absorbing Capacity
- Staff issued RAI and applicant responded
- Commitment to continue Boral test coupon surveillance through period of extended operation
- Staff concluded that Water Chemistry Program will adequately manage loss of material from general corrosion of Boral, and the Boral Surveillance Program will adequately manage the reduction of neutron absorption capacity aging effect for the period of extended operation

- Section 3.7 – Conclusion
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that aging effects will be managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, per 10 CFR 54.21(a)(3)

- 4.1 Introduction
- 4.2 Neutron Embrittlement of the Reactor Vessel and Internals
- 4.3 Metal Fatigue of Piping and Components
- 4.4 Leak-Before-Break Analysis of Primary System Piping
- 4.5 Fuel Transfer Tube Bellows Design Cycles
- 4.6 Crane Load Cycle Limits
- 4.7 Loss of Prestress in Concrete Containment Tendons
- 4.8 Environmental Qualification of Electrical Equipment

- Section 4.2 - Neutron Embrittlement of the Reactor Vessel and Internals
  - Charpy Upper-Shelf Energy for Beltline Plates and Forgings
  - Charpy Upper-Shelf Energy for Beltline Welds (Equivalent Margins Analysis)
  - Pressurized Thermal Shock Limits (RT_{PTS}) for Reactor Vessel Materials Due to Neutron Embrittlement

Section 4.2 – Charpy Upper-Shelf Energy for Beltline Plates, Forgings, and Welds

Limiting Beltline Material for Plates & Forgings — Lower Shell Plate (C3251-1) Unit 1

% CU	52 EFPY Fluence 1/4T Location, n/cm^2	Initial Charpy USE at 1/4T, (ft-lbs)	52 EFPY Charpy USE at 1/4T, (ft-lbs)	Acceptance Criterion per 10 CFR 50, App. G (ft-lb)
0. 11	1.153 X 10^{19}	81	64	>50

Limiting Beltline Weld— US to LS Circ Weld * (WF-25) Unit 1

% CU	52 EFPY Fluence 1/4T Location, n/cm^2	Initial Charpy USE at 1/4T, (ft-lbs)	52 EFPY Charpy USE at 1/4T, (ft-lbs)	Acceptance Criterion per 10 CFR 50, App. G (ft-lb)
0. 34	1.119 X 10^{19}	70	41.4	EMA

* The value for US to LS Circ Weld (WF-25) is the bounding value for beltline welds

Section 4.2: Pressurized Thermal Shock Limits (RT_{PTS}) for Reactor Vessel Materials Due to Neutron Embrittlement

Limiting Beltline Material for Plates & Forgings — Lower Shell Plate (C3307-1) Unit 1

% CU %Ni	52 EFPY Fluence (n/cm^2)	Initial RT_{NDT} ^0F	RT_{PTS} ^0F	Acceptance Criterion per 10 CFR 50.61, ^0F
0.12 0.55	1.971E+19	+1	161.8	<270°F

Limiting Beltline Weld—NB to US Circ Weld (WF-70) Unit 1

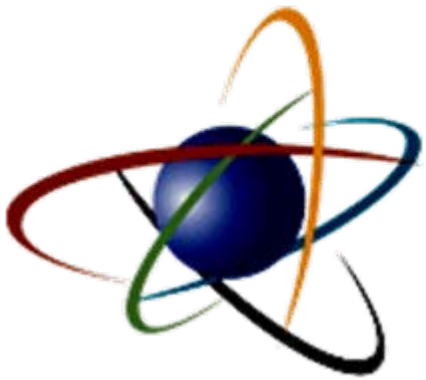
% CU %Ni	52 EFPY Fluence (n/cm^2)	Initial RT_{NDT} ^0F	RT_{PTS} ^0F	Acceptance Criterion per 10 CFR 50.61, ^0F
0.32 0.58	1.836E+19	-31.1	263.8	<300°F

- Section 4.3 – Metal Fatigue of Piping and Components
  - 60-year fatigue analyses were performed for the applicable high-fatigue locations of NUREG/CR-6260
  - Initial analysis indicated that 4 locations had a CUF >1.0:
    - Reactor Vessel Lower Head – Instrument Nozzle Penetration Weld
    - Reactor Vessel Outlet Nozzle
    - Pressurizer Surge Line (elbow)
    - Makeup/High Pressure Injection Nozzle
  - Further evaluation performed and final results indicated that the locations have an EAF-adjusted CUF value < 1.0
  - TMI-1 will manage fatigue of Class 1 components using the Metal Fatigue of Reactor Coolant Pressure Boundary Aging Management Program

- Section 4.3.2 – Evaluation of Reactor Water Environmental Effects on Fatigue Life of Piping and Components, GSI-190
  - Confirmatory Item 4.3.2-1
    - Fen values calculated based on assumed DO (dissolved oxygen) concentration data lower than 0.05 ppm
    - Staff questioned whether 0.05 ppm DO was bounding
    - Applicant indicated that 0.05 ppm was bounding since TMI-1 historically maintained its DO levels at less than 0.005 ppm, and administrative controls are in place to maintain it at or below this level
    - Applicant submitted additional information which staff found acceptable and is in process of closing out item and revising SER

- Section 4.9 – Conclusion
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant provided an adequate list of TLAAs, per 10 CFR 54.3 and that the:
    - TLAAs will remain valid for the period of extended operation, per 10 CFR 54.21(c)(1)(i)
    - TLAAs have been projected to the end of the period of extended operation, per 10 CFR 54.21(c)(1)(ii)
    - Aging effects will be managed for the period of extended operation, per 10 CFR 54.21(c)(1)(iii)

- The staff's conclusion regarding the LRA for TMI-1 will be provided in the Final SER scheduled to be issued in July, 2009



U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Exelon Nuclear

Introductions

– Mike Gallagher	VP, Exelon License Renewal
– Steve Queen	TMI-1 Operations Director
– Al Fulvio	Manager, License Renewal
– Pat Bennett	TMI-1 Engineering Manager
– Chris Wilson	Licensing Lead

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Agenda

• Introductions	Mike Gallagher
• Site Description	Al Fulvio
• Operating History	Steve Queen
• GALL Consistency, Commitments, and Confirmatory Item	Al Fulvio
• Topics of interest	
– Recent LR Industry Issues	Al Fulvio
– Reactor Building Liner	Pat Bennett
– Medium Voltage Cables	Steve Queen
– Fuel Storage Racks Containing Boral	Al Fulvio
• Questions and Close	Mike Gallagher

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Site Description and Operating History

Site Description

- TMI-1 is a Babcock and Wilcox (B&W) Pressurized Water Reactor located on Three Mile Island, which is situated in the Susquehanna River

- Also located on Three Mile Island is TMI-2, which is owned by First Energy Corporation
  - TMI-2 has been shut down since the 3/28/79 accident and is now in a safe storage mode called Post Defueling Monitored Storage (PDMS)

Site Description

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Operating History

• Commercial Ops	09/74
• TMI-2 Accident	03/79
• TMI-1 stays shutdown	03/79
• TMI-1 Restart	10/85
• 1.3 percent power uprate to 2568 MWt	07/88
• Sale of TMI-1 from GPU to AmerGen	12/99
• Turbine Rotor replacements	11/01
• Main and Aux Transformers replacement	11/01
• New Reactor Head	11/03
• LRA Submitted	01/08
• Transfer license from AmerGen to Exelon	01/09
• Scheduled installation of new S/Gs (1R18)	Fall 2009
• Two consecutive breaker to breaker runs	2001-2005
• Unit Capability Factor (2007 & 2008 average)	95.28%
• Current License Expires	04/19/14

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GALL Consistency Commitments Confirmatory Item

GALL Consistency and Commitments

- Total Aging Management Programs – 38
  - Consistent with GALL – 24
  - Exceptions to GALL – 14

- License Renewal Commitments managed through the fleet wide Exelon Commitment tracking program which implements the guidance provided by the Nuclear Energy Institute (NEI) NEI 99-04, Revision 0, "Guidelines for Managing NRC Commitment Changes,“

- Total of 43 License Renewal Commitments
  - 38 Aging Management Programs
  - PWR Vessel Internals
  - Install new Steam Generators prior to PEO
  - Submit new Pressure-Temperature limit curves to the NRC prior to exceeding 29 EFPY and prior to PEO
  - Weld repair the Reactor Building liner prior to the PEO
  - Boral Test Coupon Surveillance for the fuel storage racks will continue through the PEO

Confirmatory Item

CI 4.3.2-1 concerns the bounding assumption of less than 0.050 ppm for reactor coolant dissolved oxygen used in fatigue calculations

- TMI-1 controls reactor coolant to less than 0.005 ppm through implementation of EPRI guidelines
- Exelon is submitting the information to the staff to close this issue

Topic of Interest

Recent LR Industry Issues

Recent LR Industry Issues

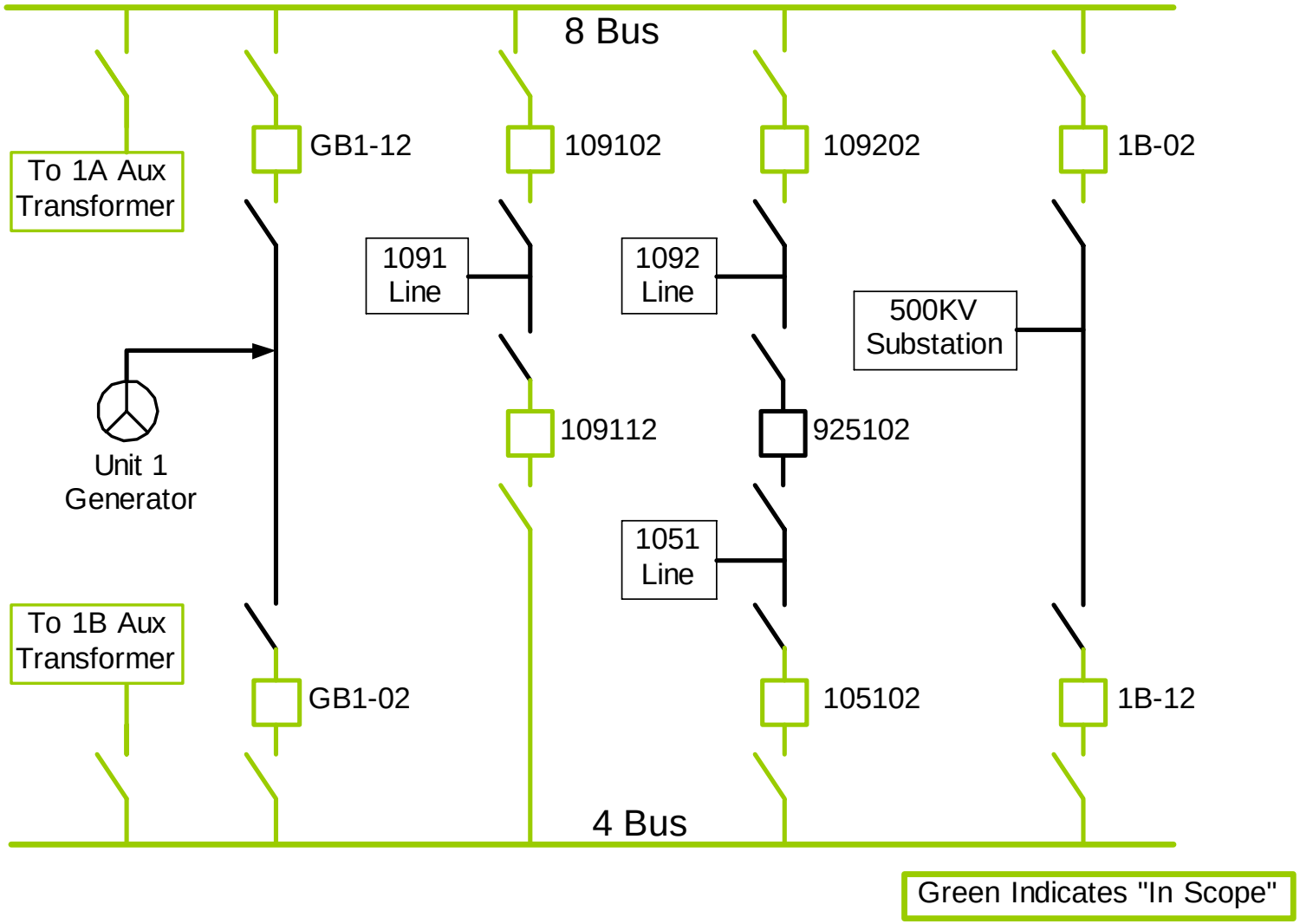
Fatigue

- Environmentally-Assisted Fatigue has been satisfactorily evaluated
- No simplified analysis methods were used

Station Blackout

- TMI-1 LRA boundary for SBO recovery path includes the switchyard circuit breakers

TMI-1 Switchyard

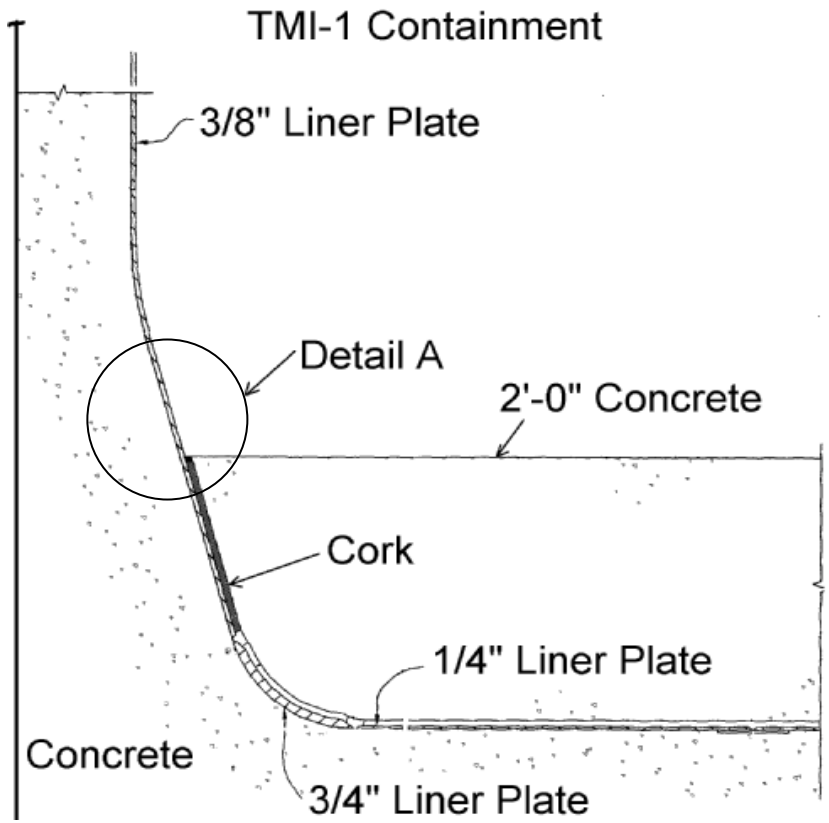


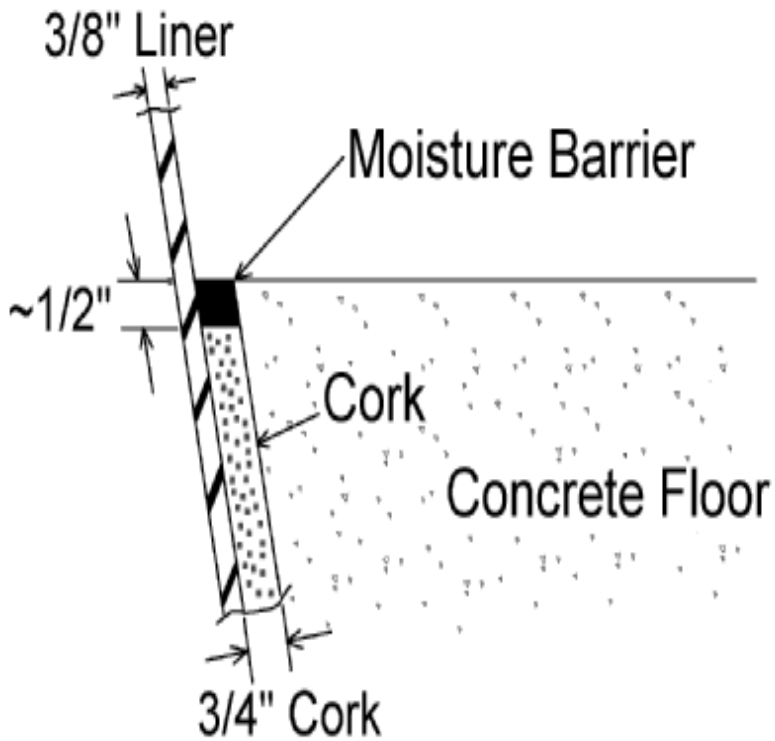
Topic of Interest

Reactor Building Liner Corrosion

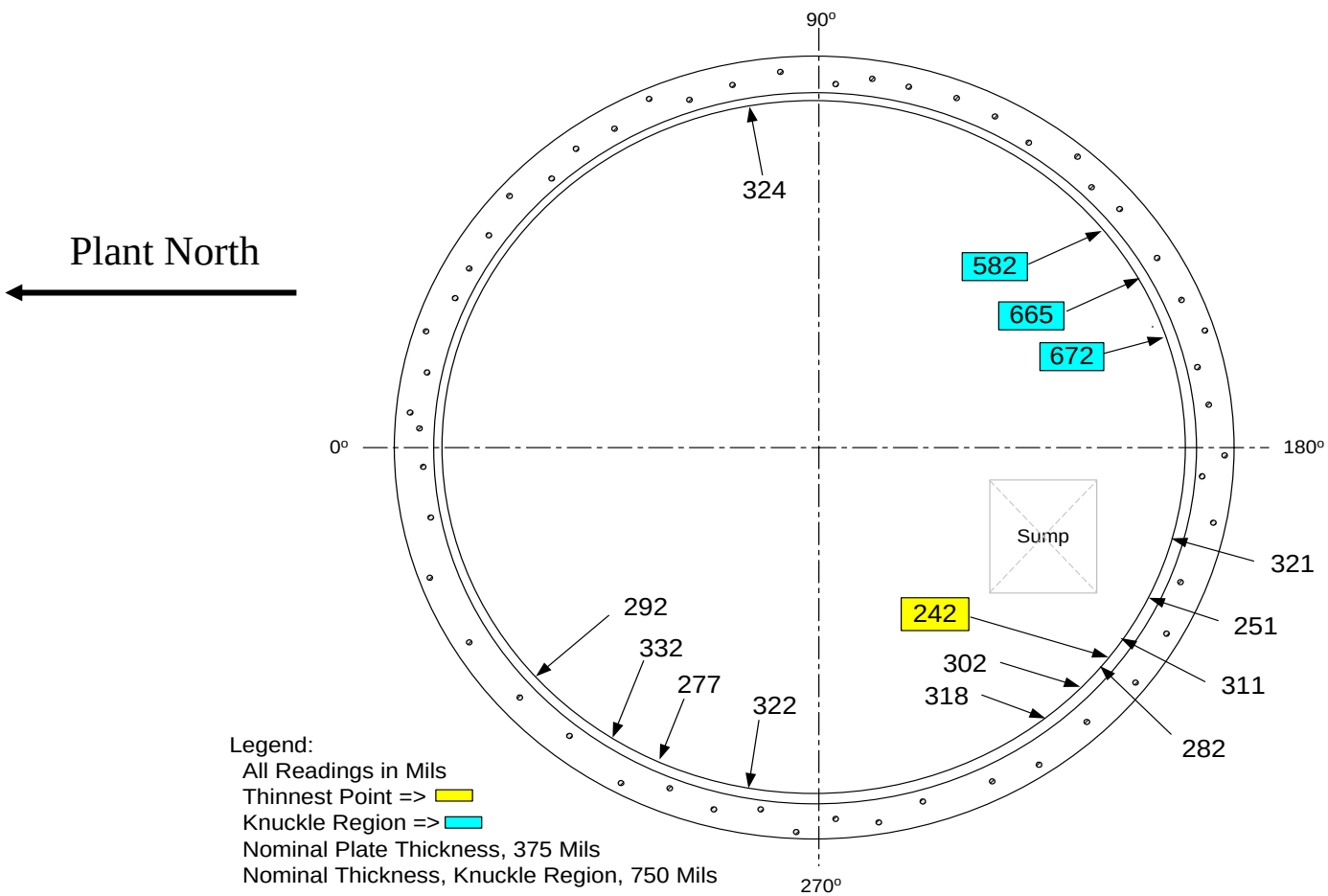
Issue

Past leakage and a degraded moisture barrier resulted in corrosion behind and just above the moisture barrier.





Areas of Corrosion at Moisture Barrier to Liner interface



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Reactor Building Liner Corrosion

- Identified
  - Corrosion identified in 1990s and monitored and inspected per IWE Program
- Cause
  - Borated water leakage and degraded moisture barrier
- Mitigation
  - Corrected leaks and established Boric Acid Corrosion Control program
  - Inspected entire perimeter in Fall 2007
  - Measured thickness of corroded areas. Liner meets design requirements.
  - Removed old moisture barrier in 2007, cleaned, re-coated, and installed new improved moisture barrier
  - Inspect 100% of the moisture barrier every Refueling outage starting 2009
- Repair Plan
  - Weld repair prior to PEO (scheduled Fall 2009 with the Integrated Leak Rate Test)

Topic of Interest

Medium Voltage Cables

Medium Voltage Cables

ISSUE

- Periodic TMI-1 cable vault inspection results identified some cable vaults with repeat occurrences of rainwater accumulation and cable submergence

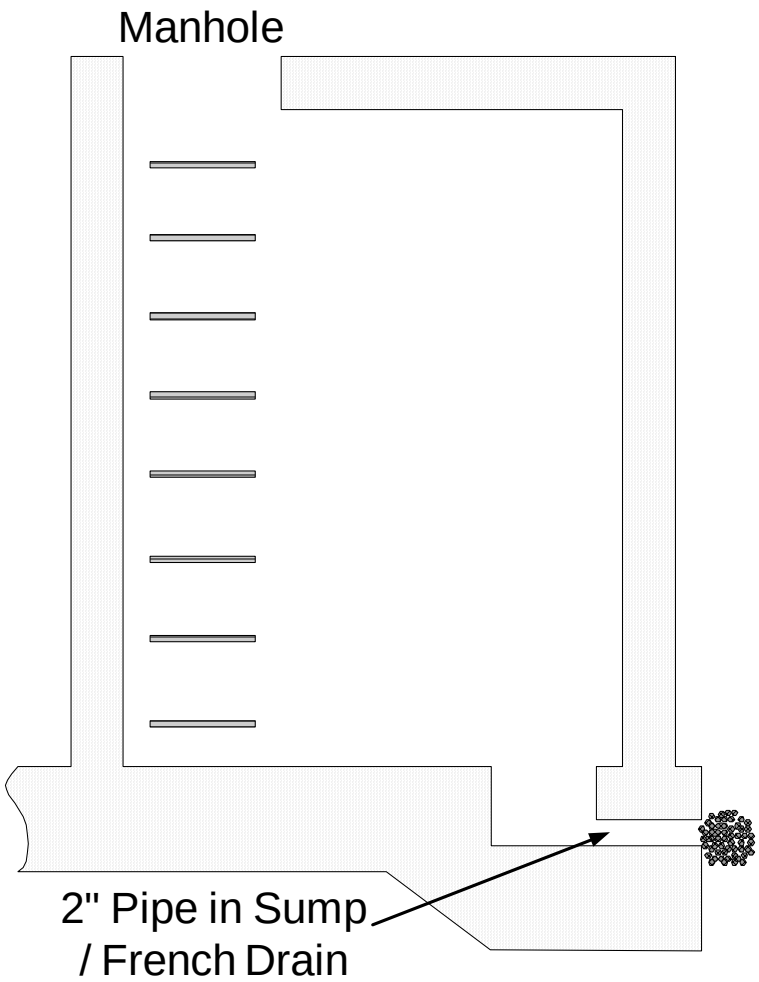
- 37 total TMI-1 cable vaults

- 8 cable vaults in scope for License Renewal Inaccessible Medium Voltage Cable aging management program

- There have been no failures of Medium Voltage Cables at TMI-1

Exelon Nuclear

Medium Voltage Cables



Typical Cable Vault

- Typical depth 8 to 15 feet
- Bottom of Cable Vault located 5 to 15 feet above water table
- Compartmentalized
- French drain
- Cables at varying elevations reflecting terrain & cable routes

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Medium Voltage Cables

ACTIONS

- Implement semi-annual inspection
- Implement cable vault improvement initiative, including:
  - Prevent rainwater intrusion
    - Install lid gaskets
    - Improve grading/surrounding environment to prevent run-off into vaults
  - Restore/maintain French drains & drains between vaults
- Adjust frequency of inspection based on inspection results following remediation
- Perform Cable Tests prior to PEO and every 10 years per GALL

CONCLUSION

- This new Program will keep the medium voltage cables dry or infrequently submerged to effectively manage aging.

Topic of Interest

Fuel Storage Racks Containing Boral

Fuel Storage Racks Containing Boral

Issue

The formation of blisters on Boral neutron absorber material has the potential to affect dimensional assumptions used in the criticality analysis of Region 1 type high-density spent fuel storage racks

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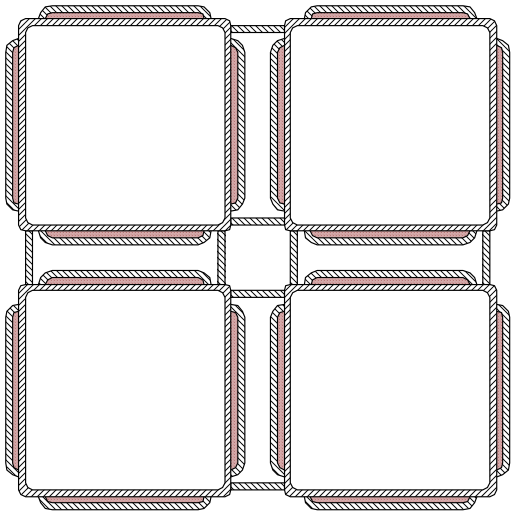
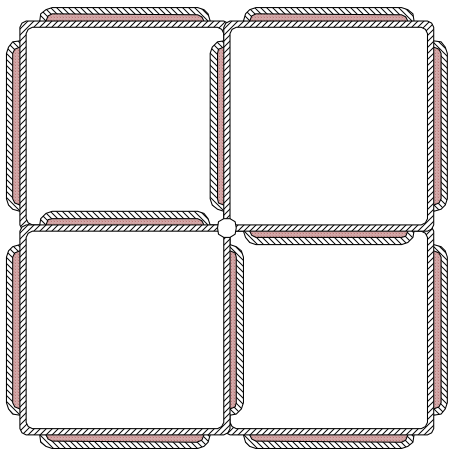
Fuel Storage Racks Containing Boral





TMI-1 uses two types of high density storage racks:

Region 1 high-density storage racks have a water gap (flux trap) between storage cells

Region 2 high-density storage racks do not have a water gap (flux trap) between storage cells

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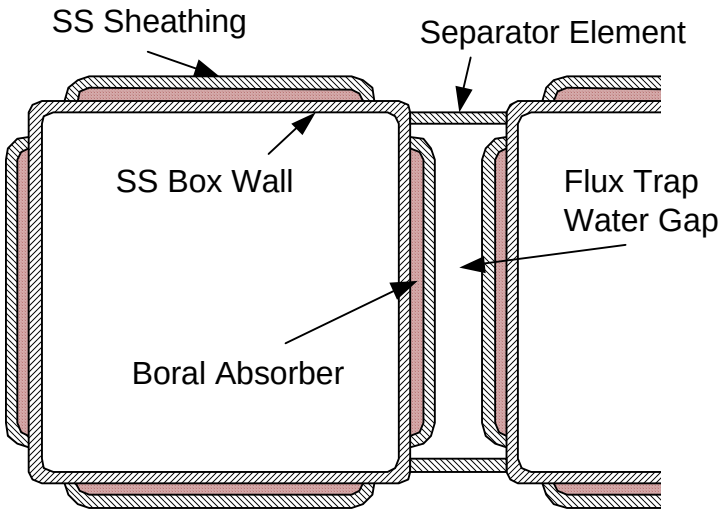
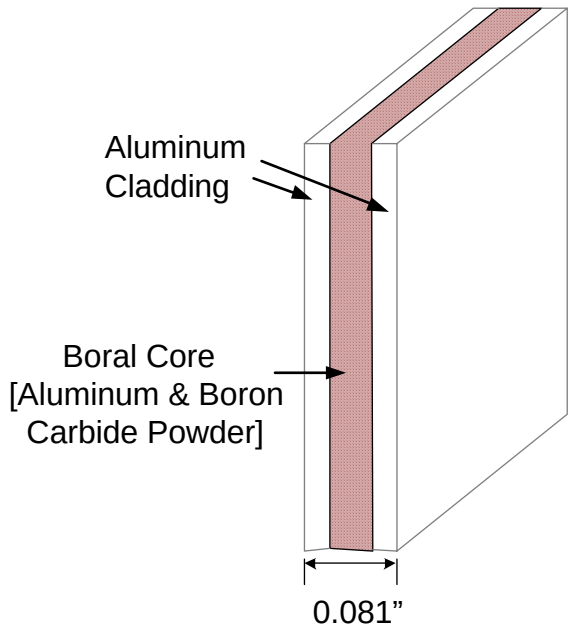
Fuel Storage Racks Containing Boral



In PWR Region 1 storage racks, two plates of an absorber material (Boral) are located between each cell, separated by a water gap (flux trap)



Each plate of Boral absorber material is comprised of an aluminum and boron carbide powder core with aluminum cladding on each side

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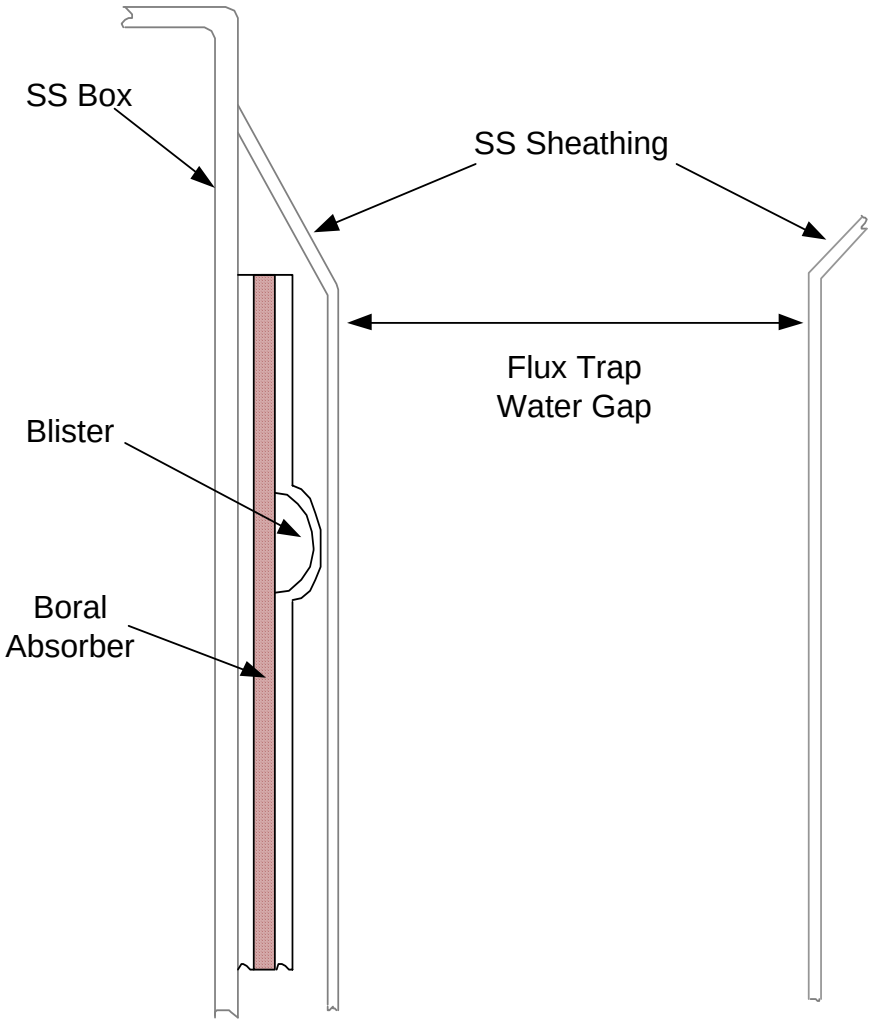
Fuel Storage Racks Containing Boral



The Boral absorber is contained within a pocket formed on each side of the rack cell by the stainless steel cell box wall and a stainless steel sheath

If a blister forms on the Boral but does not deform the sheathing, the analyzed flux trap water gap dimension is not affected

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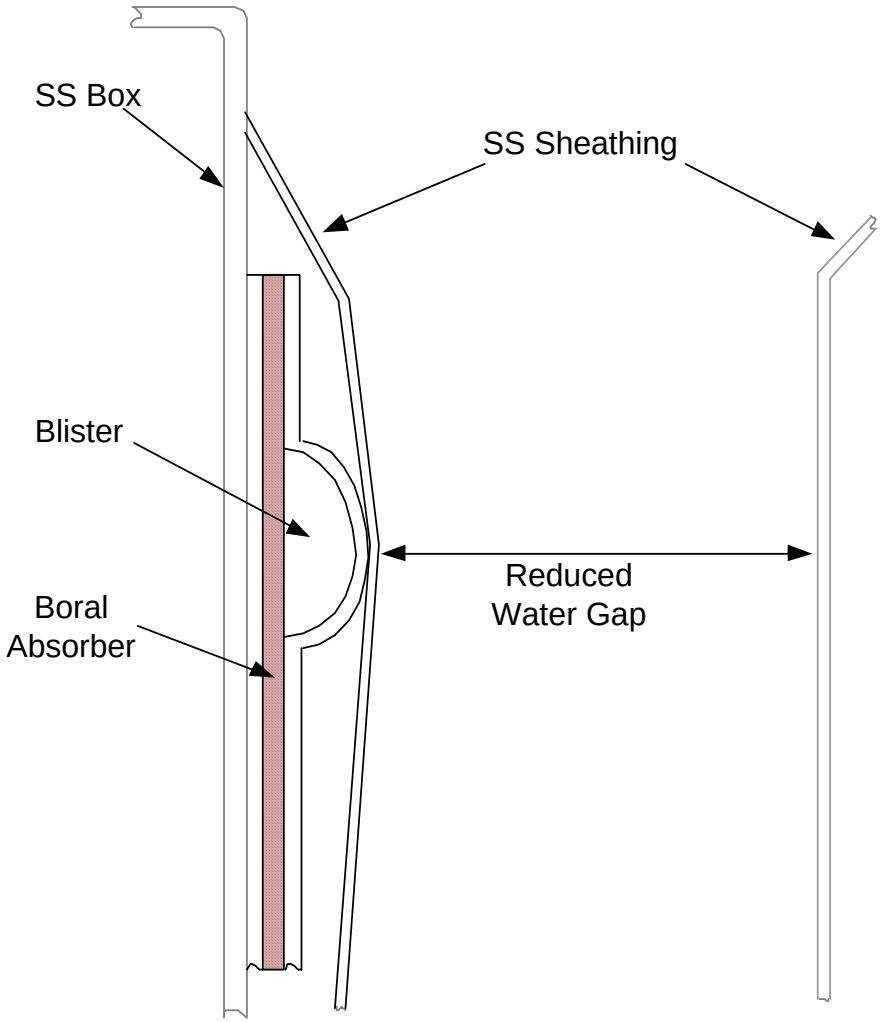
Fuel Storage Racks Containing Boral



If a blister forms on the Boral absorber sufficient to locally deform the sheathing, the flux trap water gap dimension can be reduced at that location

The pocket containing the Boral panel is water filled. Although water intrusion into the Boral core is the cause of corrosion that can form a blister, it is conservative to assume the blister is not water filled

Fuel Storage Racks Containing Boral

Background & Coupon Surveillance Results

- High-density fuel pool storage racks containing Boral panels were first installed at TMI-1 in 1992
- Boral coupon surveillance evaluations were performed in 1995, 1997, 1999, 2001, and 2008
- No blistering was found in coupons evaluated in 1995, 1999, or 2001
- 1997 coupon evaluation: seven small blisters found -
  - Diameter ~ 0.3”, depths between 0.01” and 0.02”
- 2008 coupon evaluation: one blister found -
  - Diameter ~ 1.0”, depth 0.058” and was water-filled
- Neutron attenuation tests show no loss of boron in the Boral and no reduction in neutron absorption capacity in any coupon, even at the location of the blister

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Fuel Storage Racks Containing Boral

Issue Summary

- Blisters have been observed on TMI-1 Boral surveillance coupons
- The potential effect of blistering is bounded by the uncertainties in the analysis and is well within existing margins to the regulatory requirement for k_{eff}
- The TMI-1 Boral coupon surveillance program will continue throughout the period of extended operation

Fuel Storage Racks Containing Boral

Aging Management

- LRA credits the Water Chemistry program with aging management for loss of material due to general corrosion of the aluminum cladding of the Boral absorber
- Boral coupon surveillance program will continue throughout the period of extended operation
  - Evaluations will determine that any effect on neutron multiplication from a postulated reduction in the flux trap water gap is within the design requirement

Questions?

(202) 234-4433

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Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Three Mile Island Nuclear Station, Unit - 1 (TMI-1)

Safety Evaluation Report (SER) with Open Items

April 1, 2009

Jay E. Robinson, Project Manager
Office of Nuclear Reactor Regulation

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Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Program and Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

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Overview

- LRA Submitted by letter dated January 8, 2008
- Babcock & Wilcox (B & W) Pressurized Water Reactor (PWR), carbon steel-lined concrete (DRYAMB) containment
- 2568 MWth, 852 MWe
- Operating License DPR-050 expires April 19, 2014
- Located 10 miles southeast of Harrisburg, PA
- Unit 2 Shutdown in safe storage mode of Post Defueling Monitored Storage (PDMS)

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Overview

- Safety Evaluation Report issued March, 2009
- 0 Open Items
- 1 Confirmatory Item
- 123 RAIs issued
- 43 Commitments

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Overview

- Scoping and Screening Methodology Audit
  - May 19, 2008 – May 22, 2008
- Aging Management Program (AMP) Audit
  - July 14, 2008 – July 16, 2008
  - July 28, 2008 – August 1, 2008
- Regional License Renewal Inspection
  - November 17, 2008 – November 21, 2008
  - December 08, 2008 – December 12, 2008

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Section 2: Structures and Components Subject to Aging Management Review

- Section 2.1 - Scoping and Screening Methodology
  - Based on its review of the LRA and additional information submitted as a result of Requests for Additional Information (RAIs), the staff determined that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1)
- Section 2.2 - Plant-Level Scoping Results
  - Based on its review of the LRA and additional information submitted as the result of an RAI, the staff concluded the applicant identified the systems and structures within the scope of license renewal per 10 CFR 54.4(a)

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Section 2: Structures and Components Subject to Aging Management Review

- Section 2.3 – Scoping and Screening Results: Mechanical Systems
  - The staff identified nine systems that required the applicant to revise their application to add additional components into scope
    - Examples of component types omitted included: Fuel tank for the standby diesel engine for the emergency diesel generator air start system air compressor, lube oil lines, and intake bar racks, which were subsequently added to scope and subject to an AMR
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant identified the mechanical system components within the scope of license renewal per 10 CFR 54.4(a) and subject to an aging management review per 10 CFR 54.21(a)(1)

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Section 2: Structures and Components Subject to Aging Management Review

- Section 2.4 – Scoping and Screening Results: Structures
  - The staff identified one component that required the applicant to revise their application to add the component into scope
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that there were no omissions of structures or structural components from scope of license renewal per 10 CFR 54.4(a), and no omissions from AMR per 10 CFR 54.21(a)(1)

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Section 2: Structures and Components Subject to Aging Management Review

- Section 2.5 – Scoping and Screening Results: Electrical Systems/Commodity Groups
  - Station blackout recovery path includes the complete circuits within the scope of license renewal
  - Based on its review of the LRA and additional information submitted as the result of an RAI, the staff concluded that there were no omissions of electrical systems/commodity groups from scope of license renewal per 10 CFR 54.4(a), and no omissions from AMR per 10 CFR 54.21(a)(1)

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Section 2: Structures and Components Subject to Aging Management Review

- Section 2.6 – Conclusion for Scoping and Screening
  - Based on its review of the LRA, the onsite audit results, and additional information submitted as the result of RAIs, the staff concluded that:
    - The applicant's scoping and screening methodology meets the requirements of 10 CFR 54.4 and 54.21(a)(1), and
    - That the applicant adequately identified those SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a), and those SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1)

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License Renewal Inspections
Glenn Meyer
Region I Inspection Team Member

- Inspection Objectives
  - Scoping of Non-Safety SSCs
  - 19 Aging Management Programs (AMPs)
- Scoping
  - Scoping of non-safety SSCs – generally accurate and acceptable
  - Structural and spatial interactions reviewed

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License Renewal Inspections

- Aging Management Programs
  - Reviewed AMP program procedures and records
  - Walked down systems in plant
  - Evaluated operating experience
  - Concerns – Minimal; addressed onsite

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License Renewal Inspections

- Item of Interest
  - Operating Experience Approach
- Inspection Conclusions
  - Scoping of non-safety SSCs and aging management programs are acceptable
  - Inspection results support a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained.

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License Renewal Inspections

- Current Performance
  - Licensee Response Column of Action Matrix
  - All Findings – Green
  - All Performance Indicators (PIs) - Green

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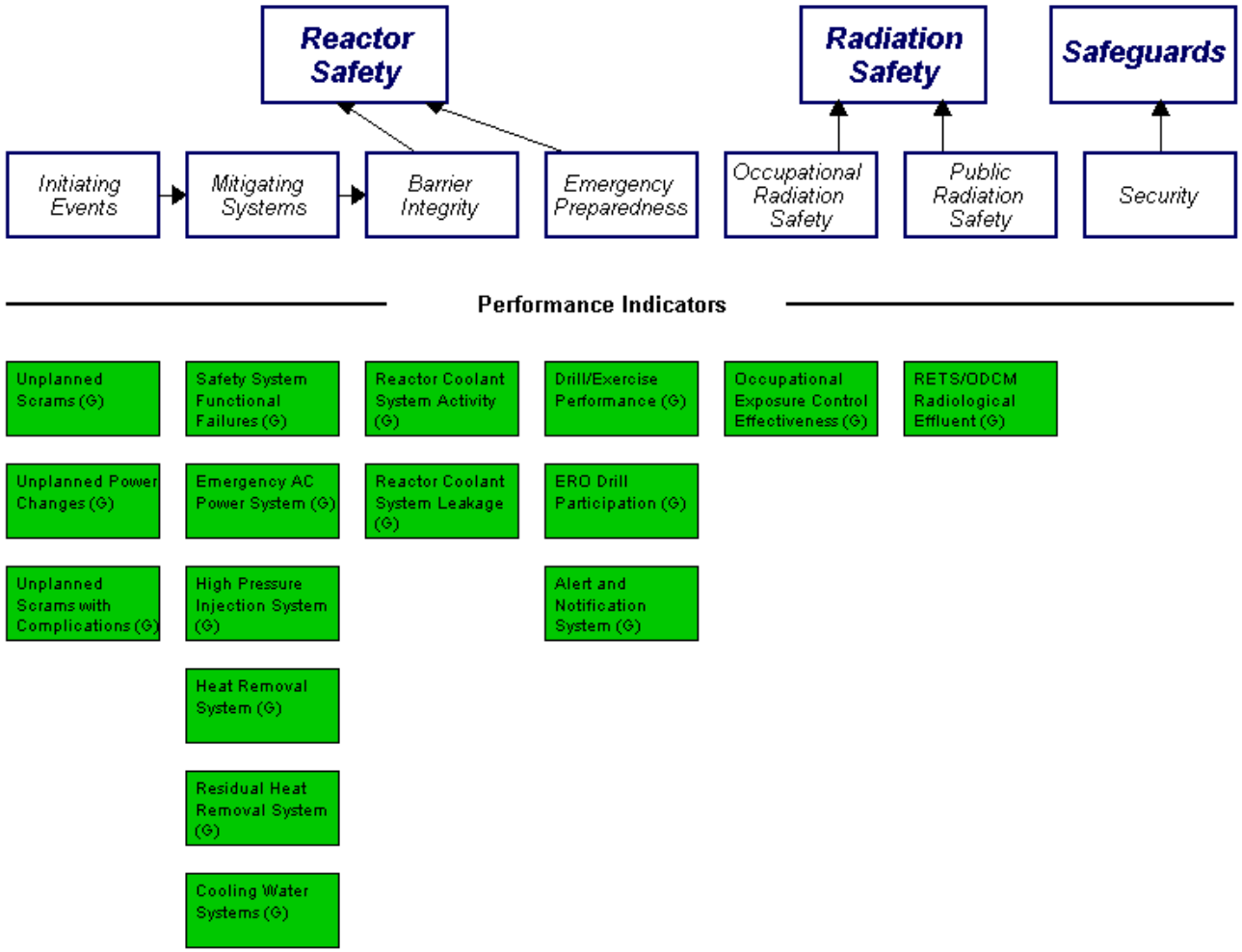
License Renewal Inspections



Last Modified: January 30, 2009

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Section 3: Aging Management Review Results

- Section 3.0 – Aging Management Programs
- Section 3.1 – Reactor Coolant System
- Section 3.2 – Engineered Safety Features
- Section 3.3 – Auxiliary Systems
- Section 3.4 – Steam and Power Conversion System
- Section 3.5 – Containments, Structures and Component Supports
- Section 3.6 – Electrical Commodity Group

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Section 3: Aging Management Review Results

- Section 3.0.3 – Aging Management Programs (AMPs)
  - 38 – AMPs
    - 7 New Programs
    - 31 Existing Programs
  - 21 consistent with GALL Report
    - 9 with enhancements
    - 1 plant specific
  - 11 with exceptions
  - 6 with both enhancements and exceptions

Section 3: Aging Management Review Results

Groundwater Sampling

- Groundwater sampling for pH, chloride, and sulfate concentrations will be performed every 5 years during the period of extended operation.
- TMI-1 Groundwater is non-aggressive

	Acceptance Criteria	2007	2005 (Three Samples taken)
pH	**>5.5**	**7.4**	**7.8/7.8/7.7**
Chlorides	**<500 ppm**	**58 ppm**	**57.3/42.4/65.5 ppm**
Sulfates	**<1500 ppm**	**27 ppm**	**44.2/53.3/48.0 ppm**

Reactor Head Closure Studs

- During AMP audit, staff identified use of Dow Corning G-N lubricant for reactor head closure studs
  - Composed of 14% Molybdenum Disulfide
  - Molybdenum Disulfide may promote stress corrosion cracking
- Staff issued RAI and applicant agreed to enhance program by selecting an alternate stable lubricant that is compatible with the fastener material and the environment prior to the period of extended operation
- Staff found applicant's response to the RAI acceptable and their concern resolved

Reactor Building Liner

- Staff identified that operating experience indicated corrosion at several locations due to moisture intrusion through the moisture barrier
- Staff issued RAI and applicant committed to restore the liner to its nominal plate thickness by weld repair for previously identified corroded areas where thickness of the base metal is reduced by more than 10% of the nominal plate thickness, prior to the period of extended operation
- Applicant performed engineering evaluation and determined the intended function of the liner is currently being maintained
- Based on its review, the staff found the applicant's proposed corrective actions acceptable

Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

- TMI-1 operating experience shows that inaccessible medium-voltage cables in several manholes experienced water submergence for more than a few days
- During AMP audit staff found cables submerged under water in two manholes
- Staff issued RAI for submergence certification for cables or action plan to preclude cable degradation
- Applicant will adjust frequency of inspections based on inspection results in order to keep cables from significant moisture
- Water in manholes is a generic, current operating plant issue that is being addressed during the current period of operation through the reactor oversight process in accordance with the requirements of 10 CFR Part 50

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Section 3: Aging Management Review Results

- Section 3.0.3 – Aging Management Programs (AMPs)
  - Based on it's audit and review and additional information submitted as the result of RAIs, the staff concluded that the effects of aging will be managed so that intended function(s) will be maintained during the period of extended operation, per 10 CFR 54.21(a)(3)

Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

- Water Chemistry Program
  - Loss of Material due to General Corrosion
- Boral Surveillance Program
  - Reduction of Neutron-Absorbing Capacity
- Staff issued RAI and applicant responded
- Commitment to continue Boral test coupon surveillance through period of extended operation
- Staff concluded that Water Chemistry Program will adequately manage loss of material from general corrosion of Boral, and the Boral Surveillance Program will adequately manage the reduction of neutron absorption capacity aging effect for the period of extended operation

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Section 3: Aging Management Review Results

- Section 3.7 – Conclusion
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that aging effects will be managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, per 10 CFR 54.21(a)(3)

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Section 4: Time-Limited Aging Analysis

- 4.1 Introduction
- 4.2 Neutron Embrittlement of the Reactor Vessel and Internals
- 4.3 Metal Fatigue of Piping and Components
- 4.4 Leak-Before-Break Analysis of Primary System Piping
- 4.5 Fuel Transfer Tube Bellows Design Cycles
- 4.6 Crane Load Cycle Limits
- 4.7 Loss of Prestress in Concrete Containment Tendons
- 4.8 Environmental Qualification of Electrical Equipment

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Section 4: Time-Limited Aging Analysis

- Section 4.2 - Neutron Embrittlement of the Reactor Vessel and Internals
  - Charpy Upper-Shelf Energy for Beltline Plates and Forgings
  - Charpy Upper-Shelf Energy for Beltline Welds (Equivalent Margins Analysis)
  - Pressurized Thermal Shock Limits (RT_{PTS}) for Reactor Vessel Materials Due to Neutron Embrittlement

Section 4.2 – Charpy Upper-Shelf Energy for Beltline Plates, Forgings, and Welds

Limiting Beltline Material for Plates & Forgings — Lower Shell Plate (C3251-1) Unit 1

% CU	52 EFPY Fluence 1/4T Location, n/cm^2	Initial Charpy USE at 1/4T, (ft-lbs)	52 EFPY Charpy USE at 1/4T, (ft-lbs)	Acceptance Criterion per 10 CFR 50, App. G (ft-lb)
0. 11	1.153 X 10^{19}	81	64	>50

Limiting Beltline Weld— US to LS Circ Weld * (WF-25) Unit 1

% CU	52 EFPY Fluence 1/4T Location, n/cm^2	Initial Charpy USE at 1/4T, (ft-lbs)	52 EFPY Charpy USE at 1/4T, (ft-lbs)	Acceptance Criterion per 10 CFR 50, App. G (ft-lb)
0. 34	1.119 X 10^{19}	70	41.4	EMA

*** The value for US to LS Circ Weld (WF-25) is the bounding value for beltline welds**

Section 4.2: Pressurized Thermal Shock Limits (RT_{PTS}) for Reactor Vessel Materials Due to Neutron Embrittlement

Limiting Beltline Material for Plates & Forgings — Lower Shell Plate (C3307-1) Unit 1

% CU %Ni	52 EFPY Fluence (n/cm^2)	Initial RT_{NDT} ^0F	RT_{PTS} ^0F	Acceptance Criterion per 10 CFR 50.61, ^0F
0.12 0.55	1.971E+19	+1	161.8	<270°F

Limiting Beltline Weld—NB to US Circ Weld (WF-70) Unit 1

% CU %Ni	52 EFPY Fluence (n/cm^2)	Initial RT_{NDT} ^0F	RT_{PTS} ^0F	Acceptance Criterion per 10 CFR 50.61, ^0F
0.32 0.58	1.836E+19	-31.1	263.8	<300°F

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Section 4: Time-Limited Aging Analysis

- Section 4.3 – Metal Fatigue of Piping and Components
  - 60-year fatigue analyses were performed for the applicable high-fatigue locations of NUREG/CR-6260
  - Initial analysis indicated that 4 locations had a CUF >1.0:
    - Reactor Vessel Lower Head – Instrument Nozzle Penetration Weld
    - Reactor Vessel Outlet Nozzle
    - Pressurizer Surge Line (elbow)
    - Makeup/High Pressure Injection Nozzle
  - Further evaluation performed and final results indicated that the locations have an EAF-adjusted CUF value < 1.0
  - TMI-1 will manage fatigue of Class 1 components using the Metal Fatigue of Reactor Coolant Pressure Boundary Aging Management Program

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Section 4: Time-Limited Aging Analysis

- Section 4.3.2 – Evaluation of Reactor Water Environmental Effects on Fatigue Life of Piping and Components, GSI-190
  - Confirmatory Item 4.3.2-1
    - Fen values calculated based on assumed DO (dissolved oxygen) concentration data lower than 0.05 ppm
    - Staff questioned whether 0.05 ppm DO was bounding
    - Applicant indicated that 0.05 ppm was bounding since TMI-1 historically maintained its DO levels at less than 0.005 ppm, and administrative controls are in place to maintain it at or below this level
    - Applicant submitted additional information which staff found acceptable and is in process of closing out item and revising SER

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Section 4: Time-Limited Aging Analysis

- Section 4.9 – Conclusion
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant provided an adequate list of TLAAs, per 10 CFR 54.3 and that the:
    - TLAAs will remain valid for the period of extended operation, per 10 CFR 54.21(c)(1)(i)
    - TLAAs have been projected to the end of the period of extended operation, per 10 CFR 54.21(c)(1)(ii)
    - Aging effects will be managed for the period of extended operation, per 10 CFR 54.21(c)(1)(iii)

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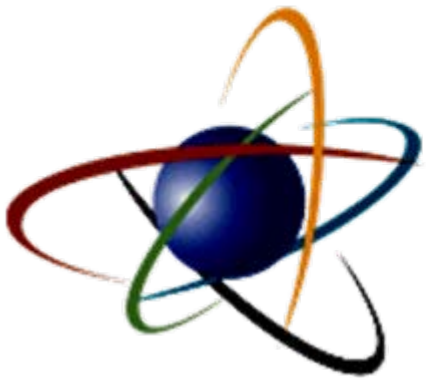
Conclusion

- The staff's conclusion regarding the LRA for TMI-1 will be provided in the Final SER scheduled to be issued in July, 2009



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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

+ + + + +

WEDNESDAY, APRIL 1, 2009

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ROCKVILLE, MD

The Subcommittee convened in Room T2B3 in the Headquarters of the Nuclear Regulatory Commission, Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Dr John Stetkar, Chair, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

JOHN W. STETKAR, Chair

JOHN D. SIEBER

SAM ARMIJO

WILLIAM J. SHACK

MARIO V. BONACA

SAID ABDEL-KHALIK

CHARLES H. BROWN, JR.

HAROLD B. RAY

MICHAEL T. RYAN