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UNITED STATES NUCLEAR REGULATORY COMMISSION'S ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

KEWAUNEE POWER STATION

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WEDNESDAY,

AUGUST 18, 2010

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ROCKVILLE, MARYLAND

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

SUBCOMMITTEE MEMBERS:

MARIO V. BONACA, Chairman

J. SAM ARMIJO, Member

CHARLES H. BROWN, Member

WILLIAM J. SHACK, Member

JOHN W. STETKAR, Member

DESIGNATED FEDERAL OFFICIAL:

GIRIJA S. SHUKLA

CONSULTANT:

JOHN J. BARTON

NRC STAFF:

BRIAN HOLIAN, NRR

JOHN DAILY, NRR

DAVID PELTON, NRR

BILL ROGERS

CAROLINE TILTON, Region III

DOMINION ENERGY KEWAUNEE:

PAUL AITKEN

PHIL BUKES

MIKE HALE

MARK HOTCHKISS

JIM RUSCH

BEN RODILL

STEVE SCASE

CHARLIE SORRELL

BILL WEBSTER

MICHAEL WILSON

DAVID WOOTEN

STEW YUEN

C-O-N-T-E-N-T-S

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

(8:28 a.m.)

OPENING REMARKS

CHAIRMAN BONACA: I am Mario Bonaca, Chairman of the subcommittee for this application. The committee members that are present are Bill Shack, John Stetkar, Sam Armijo. We have two consultants, well one consultant, John Barton, and we may have additional members as we go forward.

Mr. Girija Shukla with the ACRS is the designated federal official for the meeting.

The subcommittee will review the license renewal applications for the Kewaunee Power Station and the associated NRC staff. We will hear presentations from the NRC staff and Dominion Energy, Kewaunee representatives, and other interested persons regarding this matter.

We have received no written comments or requests for time to make oral statements from members of the public regarding to today's meeting. The meeting will be open to public attendance.

The committee will gather information and analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation at the full committee. Rules for

participation in today's meeting have been announced as part of the notice of this meeting published in the Federal Register of July 29th, 2010.

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 room when addressing the subcommittee. The participants should first identify themselves, speak with sufficient clarity and volume so that they may be easily heard.

We will now proceed with the meeting, and I call upon Mr. Brian Holian of the NRR to make introductory remarks.

STAFF INTRODUCTION

MR. HOLIAN: Thank you, Chairman, and good morning, committee.

My name is Brian Holian. I'm the director of the Division of License Renewal. The agenda for this morning's meeting is, I'll just brief introductions and turn it over to the licensee, Dominion Energy, for the Kewaunee presentation, followed by a break and then the NRC presentation on the issues.

To my right is Mr. John Daily. He's the

senior project manager for the Kewaunee project. He's also previously worked on Pilgrim and TMI projects, and this will be his first presentation to the ACRS.

Behind him is Ms. Caroline Tilton. She is the senior reactor inspector from Region 3, Division of Reactor Safety. She was the team leader, and you will hear from her later on, on inspection results.

Also behind me is Jay Robinson. He's the branch chief responsible for John and this project.

And I wanted to mention two other acting branch chiefs who have been in the office of license renewals during part of the Kewaunee review. One is Girijua Shukla from ACRS who is over for a several month rotation. So we were thankful for that opportunity that he had to come over.

And also Mr. Steve Cochran immediately behind me. Steve has been in for the last month. He's from the technical training center and has come up to ground his experience in license renewal for a good month. He's in charge of the simulators there and has taken over one of our tech branches for the last month.

With that introduction, we have other staff we might hear from later, I just wanted to

briefly pause on two of the open items out of the four that the licensee will present and we'll comment on.

One is the steam generator divider plate, probably a new item for the ACRS as you look at that. And I just wanted to mention it's not Kewaunee specific. It's interesting how it comes up out of kind of foreign experience. It's an item the staff has just deemed worth looking at, and that's why it happens to be open now. The industry has been aware of it through the steam generator EPRI groups and in license renewal we've raised it during this review as an item we thought worth looking at.

The second item that I wanted to talk on just briefly, and we'll hear more quotes from the licensee and then our staff later, is the work control process. You haven't seen that in probably the last year and a half as an open item. It was an item on previous plants, namely the Dominion fleet back at Millstone and North Anna, they used the work control process for substitute for one-time inspections.

The staff from what I understand historically has always looked at that with a guarded eye on your using a current practice but does it have the mechanisms of an aging management program. And on Kewaunee they expanded the use from what we have seen

in the past.

So we are looking through those issues with them, and making sure their program has what we think is necessary.

So with that background I'll turn it over to Mr. Steve Scace, the vice president for Kewaunee.

DOMINION ENERGY/KEWAUNEE PRESENTATION

MR. SCACE: Thank you, Mr. Holian.

Good morning, Mr. Chairman, subcommittee members, and the NRC staff in attendance.

We appreciate the opportunity to discuss our safety evaluation with the subcommittee as well as to briefly describe the Kewaunee Power Station, its current status, our license renewal process and other items of interest.

We have an experienced team here today from both our station and our nuclear corporate headquarters located outside of Richmond, Virginia. I'd like to introduce them.

First of all, Alan Price is sitting in the back. He's our engineering vice president.

Mike Wilson to my left is our director of safety and licensing at Kewaunee.

Stew Yuen to my right is the director of engineering at Kewaunee.

And Paul Aitken to Mike's left is our license renewal project manager.

We have brought a number of other folks here to ensure that any questions you have we can readily answer today.

Kewaunee is part of the Dominion fleet. The North Anna power station and the Surrey power station in Virginia and Millstone power station in Connecticut are our other stations.

Kewaunee became part of the Dominion fleet in July, 2005, when we purchased the station from Wisconsin Public Service. It had been operated by Nuclear Management Corporation prior to that.

Dominion's focus from the beginning was to operate Kewaunee safely and reliably through extended plant life. We therefore have invested significantly in both adding and developing talented personnel, and investing over $250 million in capital improvements by the end of the year 2010.

Mr. Yuen will shortly describe some of these improvements that we have made.

This investment has paid dividends as shown in our recent performance both in safety and reliability. For example over the last three years we have risen from one of the lowest-performing plants as

measured by the IMP performance indicator to among those at the top.

Being part of the fleet clearly has its advantages. For example the license renewal team headed by Mr. Aitken conducted the license renewal projects for our other three stations.

We are mindful of and will meet our commitments made as a result of license renewal. We have the resources both at the station and available from the fleet to do so.

Once again it's a pleasure to be here, and unless there are any questions for me I will turn it over to Mike Wilson.

MR. WILSON: You can see our presentation agenda for today. I will give you some basic information about the plant and its location; some information about our renewal project including its commitments; and also discuss some technical items including the open items that exist within the draft SER.

Kewaunee County is located in northeast Wisconsin on the western shore of Lake Michigan, and Lake Michigan is our ultimate heat sink. You can see that there were a Westinghouse PWR and also with a Westinghouse turbine generator.

Our containment has a sealed containment vessel with a concrete shield building. There is an annulus space between the steel containment and the concrete shield building of about seven feet. That allows us to access the outside of the steel containment, and we do inspections of that 100 percent of the accessible portions every two consecutive refueling outages, a little bit different design for containment.

CONSULTANT BARTON: Do you have an overhead or something that shows that that would show where you found the rusting containment and the moisture barrier, and has the moisture barrier inspection revealed any deterioration of the barrier?

MR. SCACE: We have a general outline of the containment and we can point out that. That is the general --

MR. SAUL: I am Charlie Saul. I'm with the applicant, lead superstructure on the project. The - like he said the containment is a stand-alone reactor containment vessel, and it's housed inside of a shield building. And there is an annulus gap around the outside of that.

CONSULTANT BARTON: Is that containment painted on the outside or coated with anything or is

it just bare skin?

MR. SAUL: It is painted on the outside.

CONSULTANT BARTON: Now where was this rust found? And where is your moisture barrier? And has that moisture barrier got any deterioration in it? I'm trying to understand. Where did you find the rust?

MR. BUKES: Phil Bukes for the applicant. WE found three areas of rusting. They were all in the annulus. One was below the equipment hatch. The other one was to the right and below the personnel hatch. And the third area was below the service water piping.

CONSULTANT BARTON: So they were all on the outside of containment in the air gap area?

MR. BUKES: That is correct.

CONSULTANT BARTON: Didn't find anything inside?

MR. BUKES: No.

CONSULTANT BARTON: And the moisture barrier is intact, and there is no deterioration of the moisture barrier?

MR. BUKES: There has been minor deterioration of the moisture barrier, mostly just tearing in the caulking.

CONSULTANT BARTON: That's been taken care of?

MR. BUKES: Yes.

CONSULTANT BARTON: Thank you.

MEMBER SHACK: When you say you inspect 100 percent of the accessible I assume you mean you are not inspecting down in the concrete, the buried stuff. But you really can - what is your mechanism for doing the visual inspections of everything outside the concrete? Is this all line of sight, or are you using cameras?

MR. BUKES: No, we use binoculars, cameras. We try to get up into - we have access to 100 percent of the annulus area by ladders and scaffolding, scaffolding and walkways, and inside containment we just use binoculars.

CONSULTANT BARTON: Okay.

MR. WILSON: I am showing you a map of the location of the plant. I'll point out two things. Notice the proximity of Green Bay, Wisconsin. It's about 20 miles from the plant. Also the proximity of Point Beach dual units, about five miles from Kewaunee Power Station to the south, operated by Florida Power & Light.

Here are some milestones within the

plant's history. Notice the uprates in power from both measure and search and recapture in 2003, followed by a stretched uprate in 2004, and a key milestone for us was the operating license expiring in December of 2013. The original license, by the way, was 1,650 Megawatts thermal. It's been uprated the two times to 1,772 megawatts thermal.

The plant is operating safely and reliably during cycle #31, in part because of the improvements we have made in the equipment and reliability. You notice it's over three years since our last automatic trip. And we describe and discuss some of those improvements in equipment reliability. I'll turn it over to our engineering director, Steve Yuen.

MR. YUEN: Good morning. Next couple of slides I'll be discussing some of the major improvements. Specifically on this slide the first two bullets are related to the replacement of copper alloy tubing. The main condenser feedwater heaters with stainless steel tube material. This was done due to ammonia reduction in the original copper alloy tubes and to reduce the impact of copper problems associated with the steam generators.

The next bullet I wanted to speak to was the steam generator replacement.

MEMBER SHACK: Just out of curiosity, did that let you change the pH of your system so you could get some protection from erosion-corrosion? No?

MR. HALE: Mike Hale for the applicant. Yes, we moved to a hydrazine and dimethylamine chemistry.

MEMBER SHACK: What is your secondary site pH now, do you know?

MR. HALE: I don't have that information with me.

MEMBER SHACK: Just somebody with water chemistry, somewhere there is a document that says something about hydrogen peroxide additions to the reactor coolant. Why?

MR. HALE: Yes, sir, we do that during our shutdown to stimulate a crud burst so that we have a crud burst when we want it.

MEMBER SHACK: Oh, that will certainly do it. Okay.

MEMBER ARMIJO: As long as we are talking about water chemistry, your condenser tubes were they admiralty brass or monel?

MR. SCACE: They were admiralty brass originals.

MEMBER ARMIJO: Okay, and did you ever

have any problems with your fuel related to the proper getting into the primary system?

MR. YUEN: No, we have not had any fuel failures I believe in about 30 years.

MEMBER ARMIJO: That's good performance there. Okay, thank you.

MR. YUEN: Could you go to the steam generator slide? The steam generators were replaced in 2001. As this slide shows the replacement consisted of essentially a two section evolution. The upper package was the original and it was refurbished with quality improvements. The discharge nozzle was fitted with a steam flow limiter, moisture separators were upgraded, and the feed ring J-tubes were replaced with frac resistant materials.

MEMBER SHACK: Was this economics, or was this to avoid cutting a hole in the containment or both?

MR. YUEN: With respect to the way we did it?

MEMBER SHACK: The way you did it this way, instead of a whole new steam generator.

MR. YUEN: Well, it's not unique. It had been done previously this way. As far as the cutting, there was essentially interference for removal, so

that is ultimately why we opted to go the way we did.

The lower package was completely replaced with the following improvements: the tubes were replaced with stress corrosion cracking resistant thermally treated alloy 690 tube material. The support plates were changed from carbon steel to stainless steel with a quatrefoil tube hole design which reduces the likelihood of tube denting, due to corrosion, product buildup around the tubes, and in addition, the divider plate on the primary side was changed to alloy 600 with welded alloy 690 material. And we will actually be discussing that later in the presentation.

MEMBER SHACK: You got three out of four right. (Laughter)

MR. YUEN: So as I said, this type of generator replacement is not unique to the industry with Dominion plants previously having done it, both Surrey and North Anna as well as others in the industry.

And the last thing I wanted to touch on in this slide was the reactor head replacement. The reactor vessel head was replaced due to industry issues of penetration leaks. The key changes were elimination of potential leakage paths, events and

canopy seal welds. We improved penetration material. We changed from alloy 600 to alloy 690. Our conoseals were replaced with assemblies, and we also improved our inspection capabilities by having metal reflective insulation with inspection ports installed. Next slide.

On this slide --

CONSULTANT BARTON: Are you going to show us which yard, what you're doing?

MR. YUEN: Yes, I am.

CONSULTANT BARTON: All right, thank you.

MR. YUEN: On this slide the - want to talk briefly about the pump replacements and then the switchyard improvements. Our reactor coolant pumps, we have replaced both of them. This was due to shaft cracking issues I believe that occurred at some TVA plants. We did inspect both of the shafts, our first pump shaft that was replaced and inspected. There was no evidence of any cracking. The second shaft that we replaced did have some very shallow cracking. And the new pump shafts are designed to preclude that type of racking from occurring.

CONSULTANT BARTON: It's different material?

MR. YUEN: Different material, some

actually removal of some stress risers in the shaft.

CONSULTANT BARTON: Okay.

MR. YUEN: So yes.

The other pump replacement I want to talk about briefly is service water pumps. We have replaced those with an improved design that has eliminated a need for strain bearing lubrication cooling. The bearings are now cooled by the - directly by the pump flow. The impeller material has also changed to stainless steel to reduce wear due to pumping raw Lake Michigan water.

Finally the last two bullets, if we could go to the next slide. Got two slides here. One shows our switchyard layout in 2006, and then the next one will show the switchyard once all the modifications that we are performing are complete. But this first slide shows, as you can see there are two 138 kV lines or kV buses on the left side of this drawing, and two 345 kV lines to Point Beach and North Appleton.

One of these station offsite power sources, the tertiary aux transformer, it's denoted by the acronym TAT, in the middle of the drawing there, was fed directly from a tertiary winding on the 345 and 138 kV transformer. The other offsite power supply, the reserve aux transformer which is denoted

at the bottom there by the acronym, RAT, was being fed by either of the 138 kV buses.

And finally the generator output breaker fed the 345 kV bus.

So the modifications that we are doing, as you can see from this slide, include the following improvements. When all the modifications are complete we will have a double ring bus for both the 138 kV bus as well as the 345 kV bus. We are replacing or actually we have replaced the TAT with a new transformer and our RAT will be replaced in our upcoming refueling outage.

We have also replaced our main generator step-up transformers, and we have added a second 345 to 138 kV transformer - or I'm sorry, we will be adding that this refueling outage.

We have also added new supply transformers as you will see on the bottom of that drawing, RST with LTC, to both the RAT and the TAT. That LTC is a low tap changer capability, and that will be functional following our 2011 refueling outage.

Finally the generator output breaker will feed the ring bus through additional breakers to the ring bus. These changes will improve and have improved actually the reliability of the offsite power

source through diverse redundant means, allows the safety buses to maintain voltage during periods of normal grid fluctuation through the new RAT and TAT supply transformers that have the low TAT changer capability, and also improves our maintainability of switchyard equipment through the additional breakers that have been installed.

CONSULTANT BARTON: Now who owns the switchyard, you or the power company?

MR. YUEN: It's actually split. Part of it is owned by us, and there is a part that is owned by the transmission company.

CONSULTANT BARTON: The transmission company does maintenance on their portion?

MR. YUEN: Correct.

CONSULTANT BARTON: How do you control what they do?

MR. YUEN: We actually have through the NERC/FERC agreements, there are agreements that we have set up with the transmission company on how they notify us when they are coming in to do maintenance and how that is all controlled.

CONSULTANT BARTON: Thank you.

MEMBER STETKAR: Stuart, this drawing you're showing here was not in the license renewal

application; is that correct?

MR. YUEN: That is correct. This is just for presentation purposes.

MEMBER STETKAR: Well, okay, then on this drawing there is some nice red lines and there are some nice blue lines. What specific equipment is in scope for license renewal on this drawing if this is indeed the configuration that will be in effect at the time of license renewal?

MR. AITKEN: We do have another drawing we can go to.

MEMBER STETKAR: You do? Okay, I can wait.

I can read this but let's go back to the other one; it's a lot easier for most folks to understand.

MR. AITKEN: Essentially the scoping boundary remains the same at this point in time. We've changed out a breaker from the oil fill breaker to the gas fill breaker and offset breaker. So the boundary remains at that breaker.

MEMBER STETKAR: Could you go back to the as-is drawing then?

MR. AITKEN: Go back to the other or to this drawing?

MEMBER STETKAR: This is the drawing essentially that is in the license renewal application. I mean electrically.

MR. AITKEN: Well, just for purposes of illustration the boundary remains essentially unchanged at this point in time. We've done a lot of work out in the switchyard, but we are not to the first active breaker and to the switcher. That configuration hasn't changed.

MEMBER STETKAR: Okay. But it's basically RAT/TAT out to the first active breaker, dual breakers out in the switchyard?

MR. AITKEN: That's correct.

MEMBER STETKAR: Okay.

MEMBER SHACK: Just before you go on to license renewal, I was looking through the Sanna document, and I was just curious, you've made a lot of changes to reduce your susceptibility to internal flooding, and it's dropped your CDF by almost an order of magnitude, but every time you made a change that reduced the CDF the LERF kept going up. And I was wondering if that was just due to modeling changes, or was there something that I don't understand going on? I wonder if anybody could --

MR. AITKEN: Bill, can you field that

question?

MR. WEBSTER: Yes, I am Bill Webster with the Dominion.

Every time the internal flooding the LERF was dominated primarily by steam generator tube ruptures, and just the contribution of the flooding didn't affect LERF, so LERF essentially --

MEMBER SHACK: I can understand it not changing. I had a little trouble with it going up.

MR. WEBSTER: I'd have to look at the specific modeling to give you the exact answer to that. I don't know the answer to that right off, but we can get back to you on that.

MR. YUEN: So at this time if there are no other questions I'm going to turn it over to Paul Aitken.

MR. AITKEN: Okay, thanks.

Again, I'm Paul Aitken. I'm the project manager for the Kewaunee project. And as Steve mentioned I was involved in the Millstone/Surry/North Anna license renewal projects as well.

So I'll provide an overview of the license renewal project, and then cover a couple of technical items of interest as well as cover the four open items that are currently reflected in our draft SER.

First I want to mention that we were able to staff the Kewaunee project with a very experienced team, with several years of license renewal experience stemming all the way back to the Surry/North Anna projects over 10 years ago.

The majority of the team is located in corporate offices, as Steve mentioned, but we also complemented the team with Kewaunee staff including two retired shift operation managers.

Throughout the project the license renewal team coordinated with their respective station subject matter experts in identifying operating experience as well as in reviewing many of our project technical reports, including the aging management program basis documents.

We also were very active during the license renewal outage as well as the regional inspection.

I wanted to also emphasize that we always remained engaged with the industry mainly through the NEI license renewal working group and the various discipline-based EPRI working groups over the last 10 - 11 years. This involvement has allowed us to remain in touch with the ongoing industry initiatives.

The last item that I will mention is that

Dominion has been directly involved with the review and input related to the first version and the current revision. This has been important to be part of this process along with our industry counterparts and show that the GALL reflected the latest information related to aging evaluations and aging management.

I'll move on to scoping and screening. It's a high level discussion here. The scoping process is pretty standard. We follow the guidance in NEI 95-10 revision 6. Through our process we categorized the entire plant in terms of major systems, structures and components, and we try to stay as close as practical to the existing plant's system nomenclature.

We used site component databases, control drawings and other designs and licensing documents to perform our scoping reviews.

For the in scope systems and structures, screening was performed to determine what equipment needed to be evaluated further for aging management. We performed our aging management reviews using industry guidance documents as well as using the experience from our previous license renewal projects. We identified potential aging effects through the various discipline-based EPRI tools, GALL, and our own

plant specific OE. Overall we had roughly 85 percent alignment with the GALL document in the aging management review section of the LRA.

CONSULTANT BARTON: Considering you said the experienced team you put together I was disappointed in your scoping screening. I saw more RAIs on scoping and screening, mismarked drawings and mislabeled components than I have in a lot of recent applications, and I just thought the quality of the scoping and screening was not as good in this application as I've seen in recent applications, and I see them all.

MR. AITKEN: I think the challenge as far as what was brought into scope. I thought there were a lot of continuation questions on the different drawings that we tried to work.

CONSULTANT BARTON: There were just an awful lot of RAIs on that.

MR. AITKEN: Yes. Next slide.

Let's transition now to TLAs. We do have to take a look at time-limited aging analysis under the regulations, in case our existing analysis relies on a component of time to determine its adequacy. We have a very good electronic file system of our licensing basis for the facility, and we are able to

do keyword searches and identify any analysis that mattered for licensing that depended on time.

We also went through relevant calculations and looked for anything that was dependent on time, and we also interviewed our engineers.

We also compared ourselves against similar plants to see what was in their time-limited aging analysis population. So we think we have a good list of those calculations where time matters in terms of 40 years.

One of the things we did need to relook at was the effects of increasing fluence on reactor vessel. Obviously fluence changes as you go to 60 years, so we did re-perform our analysis for that. Analysis performed for 52.1 effective full power years was based on actual historical operation through Cycle #27, and operation beyond Cycle #27 to 60 years at 95.6 percent capacity factor, that was based on 18 months full power operating cycle, and 25 day refueling outage, which are very conservative.

The formal cycle projections, we did update those for 60-year life. We used where we were at the time we prepared the application in terms of actual events we have experienced to that point, which was 32 years of plant operation, then we

conservatively projected forward to 60 years by doubling the current numbers.

Projections for 60 years fell within the assumed number of transients in the plant's design basis. And regardless of the number selected for the projection we will continue to monitor those on an ongoing basis, and if we approach one of those assumptions in terms of thermal cycles, we will take action before getting there and not waiting after the fact.

Now the environmental qualifications have all been updated for 60 years without any issues, as well as the miscellaneous remaining TOAs listed on this slide.

MEMBER STETKAR: Paul on the environmental qualifications, I noticed that there was response to a staff RAI regarding monitoring of ambient temperatures that are used for equipment qualifications and updated qualifications, and that the - apparently the last time you actually made any temperature measurements in any areas were 1991 - 92. So they are sort of 20 years old now. And it was noted that you don't have any ongoing local area ambient temperature monitoring, but you have made adjustments based on what you think might be happening in the plant.

I was also noted that you had a substantial backlog of what was characterized as unfinished EQ documentation updates. Tell me what you are doing in the environmental qualification area, and how do I have confidence that the actual in situ temperatures for these components that you are using for your EQ process are what's actually in the plant?

MR. HOTCHKISS: I am Mark Hotchkiss with Dominion. And you are correct, the ambient temperature monitoring is historical, and that is used as the input for the qualification bases. We as you mentioned we have conservatively increased ambient temperatures for different changes in the plant, for instance power uprate.

MEMBER STETKAR: How do you know they are conservative if you haven't measured them?

MR. HOTCHKISS: We didn't actually go out and confirm. However we don't expect - for instance for power uprate, we wouldn't expect any real ambient temperature change. However we applied one or two degrees of increase, so we consider that conservative. But you are correct, we didn't go measure, but we really didn't see a need.

Now to respond to whether or not our historical temperature modeling remains valid, we do

continually assess whether we need to reinitiate a program of ambient temperature modeling based on changes in the plant. And at this point we haven't felt the need. So that hasn't been done.

MEMBER STETKAR: You do that based on what, equipment modifications, changes to - supposed you backed - Dr. Shack mentioned, and I didn't look at the PRA, Bill, I'm sorry, thanks.

MEMBER SHACK: You would have found it interesting.

MEMBER STETKAR: I probably would, but there are other interesting things. You made modifications for example to reduce internal flooding. Has that involved installations of barriers that can affect airflows from location to location, ventilation mixing and therefore temperatures in the rooms?

MR. YUEN: No, the modifications that have been put in for flooding would not do that.

MEMBER SHACK: Okay, thanks.

MEMBER STETKAR: What about this back - where are you on getting caught up on your EQ documentation?

MR. HOTCHKISS: There was an EQ recovery effort --

MR. YUEN: The EQ recovery effort was

completed in January.

MR. AITKEN: Okay, it has been. Next slide.

MEMBER SHACK: You have the CFA centrifugally cast piping and elbows, and I saw two analyses. One you did the lead before break, again assuming that you've got a full and embrittled material which is a conservative and reasonable assumption.

Another one you did was a flaw tolerance analysis, and you came up with a I think six-inch 28 percent fuel wall crack. I just wondered what was the acceptance criteria for that. I am not familiar with the state of inspections of cast stainless steel. Can you see a crack like that, do you do a performance demonstration that gives you a degree of confidence you can detect a crack like that?

MR. HOTCHKISS: This is Mark Hotchkiss again from Dominion. And specifically for the flaw tolerance evaluation, the thermal embrittlement of cast iron and stainless steel evaluation, we chose the minimum detectible flaw by Section 11 as a starting point, and then the flaw tolerance grew the flaw based on the --

MEMBER SHACK: Okay, so that is the

minimum detectible flaw that you started with?

MR. HOTCHKISS: Right, grew it over a period of time and showed that - the analysis showed that it would not grow to a critical side throughout the life of the plant.

MR. AITKEN: Any other questions there?

Ultimately our whole point here of course is to get the aging management programs that provide reasonable assurance that aging will be managed in the renewed term. We ended up with a total of 34 aging management programs; 28 of those are existing programs that we will just keep on doing. Six of those programs are new and one of them is plant specific as we have noted on that slide there. That program is our alloy 600 program.

Overall we had a good degree of consistency again with the GALL as we compared it with our AMPs.

This slide presents a high level summary of the number of amendments that are currently in place. Our original license renewal application submittal identified 28 commitments in appendix A of the application. Nineteen additional commitments were added during the resolution for the request of additional information. Two commitments were actually

deleted based on the responses that were provided related to the original version of the work control process program that Brian mentioned, which I will get into a little more detail later.

So our license renewal commitments have already been entered into our site license commitment track system, just like any other NRC commitment. We are relatively close to the end of the current license, so we are moving straight into implementation activities. We are not waiting. So our goal is to be ready well in advance of the period of extended operation. We have a site license renewal implementation coordinator, along with a dedicated core team. We will support the ongoing implementation activities through coordination with the site program owners as well as working within the Dominion fleet.

As previously mentioned Dominion has four plant locations. One is the last in the fleet to pursue a renewed operating license. Four sites are in different stages of license renewal implementation activities. Surry is first in the queue, and they are currently working towards the completion of their implementation activities. As a matter of fact they have an industry assessment going on this week. We are engaged in these activities at Surry and Dominion

is leveraging the fleet to ensure Surry is successful in using those lessons learned as we work our way through the Kewaunee. In addition we have always been learning from those ahead of us in the process, and we have taken the opportunity to benchmark our peers as a means to improve our current understanding of what is required for successful implementation.

So are there any questions before I move on to the next topic?

CHAIRMAN BONACA: When I look at your programs, at Appendix B, there is quite a discussion on operating experience, but it seems to be focused all on the Kewaunee operating experience. I think the NSC has raised the same issue. Have you looked at the sister plants, industry operating experience that may be applicable to Kewaunee, to what extent have you done that? I mean the programs don't describe that.

MR. AITKEN: Well, just as part of our process, our internal operating experience review, we do receive external operating events not only from our fleet as well as from the industry. They come in, go into our corrective action process where they are reviewed, screened, filtered, assigned and dispositioned. So that would be in the dataset that we would have available to us when we go and do our

operating experience reviews. So the information is reviewed. It is available at the start of our internal corrective action program.

CHAIRMAN BONACA: Was it used?

MR. AITKEN: Oh, absolutely. It's used everyday.

CHAIRMAN BONACA: You may have an event only that leads you to believe that one-time inspection is adequate to confirm that in fact you don't have a problem, and if you look at the industry experience on the same issue you may have many examples and say that you should have a problem rather than a one-time inspection. So that's really a concern I would have is you would not be very focused only on this plant.

MR. AITKEN: We are focused on our plant, but we also have a mechanism for reviewing external information. We also are involved in industry groups, whether it's within license renewal as well as other technical groups, so there is a lot of information exchange that comes back into the fleet and it is discussed and disseminated between our respective working groups.

MEMBER STETKAR: Okay.

MEMBER STETKAR: Excuse me. I have one

off the wall curious question. I didn't do enough homework to maybe answer it otherwise. In one section there is a discussion of the bleed steam system and whether it was in scope for A2. It was mentioned that it includes non-safety related components in spatial orientation near a safety-related system located in the turbine building. What safety related equipment do you have in the turbine building at Kewaunee?

MR. AITKEN: We have very limited safety related equipment in the building. We had a steam line for the turbine driven aux feedwater pump that runs down the wall of the turbine building that we considered as safety related. And is there anything else, Ben, that you can think of?

MR. RODILL: Yes, Ben Rodill, Dominion. There is the turbine first stage turbine pressure, QA1, safety related for the plant. So anything near that we had to include in the scope for spatial considerations.

MEMBER STETKAR: And that is it as far as safety?

MR. RODILL: Yes.

MEMBER STETKAR: Okay, thanks. It is just unusual, but I am familiar with some older plants that do have things in the turbine building, so thanks.

MR. AITKEN: Fair enough.

So I'll transition at this time to two technical items of interest that we wanted to talk to the subcommittee about. One is groundwater quality, and we do have some slightly elevated boron levels in our groundwater, so we will discuss that. And secondly I'll present a histogram of reactor trip experience at Kewaunee. I think that that is something that this group is likely to review in the past.

So for groundwater quality, as you know the GALL has parameters that need to be monitored during the peak period of extended operation to minimize the potential impact on buried concrete. The parameters that are monitored include sulfates which has a value of less than 1,500 ppm, the pH values greater than 5.5, and chlorides less than 500 ppm.

Site groundwater readings during original plant construction and more recently during installation indicated that the groundwater levels for pH, chlorides and sulfates were well within the limits established by the GALL.

Here is a picture to try to get you oriented on the site here. So this is a very simplistic view. At the top we have our well

locations. You can see next to the aux building that's the north side of the aux building. We have our reactor building, shield building down there, and there is a well building, 715.

MEMBER STETKAR: Can you give us - is there a gradient on the site or is this all pretty level?

MR. AITKEN: That is down the centerline of the plant.

MEMBER STETKAR: Yes, but I'm talking about grades, slopes. Which way does water flow?

MR. SORRELL: Generally the gradient of the groundwater across the site is about 10 feet to the west and then the gradient slopes toward the lake which is to the east of the right-hand side, and it's about 25 feet as it goes across the site there, it can be 25 feet. Charley Sorrell.

MEMBER STETKAR: So generally west to east which would be left to right on this building?

MR. SORRELL: That's correct.

MEMBER STETKAR: Okay.

MR. AITKEN: So in 2007 14 wells were installed as part of the groundwater monitoring initiative, and that's what we're looking at here. And eight of the wells are located near safety-related

structures. We now use these wells as a means to collect data for monitoring groundwater based on their relative location of the wells to the structures. And their location is about 18 to 15 feet from the walls of the structure.

MEMBER STETKAR: You had no prior monitoring before 2007?

MR. AITKEN: We did when we were doing the IFSIS installation. We had a couple of monitoring locations out there, and I think we --

MR. SORRELL: We had one or two prior meetings during early - during construction. And then when we built the IFSIS facility, building those construction wells, we monitored what they were to give us a general idea. But generally we did not have groundwater monitoring on the site.

MEMBER STETKAR: No regular monitoring.

MR. SORRELL: No regular monitoring.

MR. AITKEN: So we tried to get what we could, because we started the project then the groundwater initiative project came along, and so we piggybacked off that.

So based on approximately three years of quarterly readings pH and sulfates are well within the established limits for a nonaggressive environment.

However in three of the eight wells the average chloride levels, and I say average chloride levels, exceed the conservative limit of 500 ppm.

CONSULTANT BARTON: So this is even after you stopped using salt and put down the PVC, you were still getting elevated --

MR. AITKEN: Yes.

CONSULTANT BARTON: Okay.

MR. AITKEN: So just to give you a point of reference, the average of those three wells are 597 parts per million for well 7-10; 554 parts per million for well 7-11 right next to it, and 628 parts per million for 7-15, which is this south side of the reactor building. So as you noted two of the welds are along the north wall of the aux building, and the third is on the south side of the shield building.

So we had felt this contributed to the elevated chloride, is a sodium chloride product that was used during the winter months. This product was introduced in the `90s and was used up until just a couple of years ago when we first discovered these higher levels.

We feel using this product on the paved areas in the other structure may have contributed to the slightly elevated chlorine levels in these three

wells. But obviously there was a lot of snowfall out there in these locations, actually, where we pile and accumulate snow. So all the other wells remained below the 500 ppm. So as a result the station has switched to a 50-50 sand mix which is spread at a considerably lower rate than the sodium chloride, and we have a higher contribution of sand.

CONSULTANT BARTON: It's sand and what?

MR. AITKEN: It's a sodium chloride product. I don't know if we have a trademark name.

CONSULTANT BARTON: And before you were using an all-sodium chloride?

MR. AITKEN: All sodium chloride. So we've lessened the concentration of sodium chloride.

CHAIRMAN BONACA: The three wells that you mentioned was the 7-11 --

MR. AITKEN: 7-11, 7-10 --

CHAIRMAN BONACA: 7 -10.

MR. AITKEN: So we are going back off this and get you back onto the presentation if that is okay.

So we don't feel there has been an adverse effect on the adjacent concrete, because there is a polyvinyl chloride waterproof membrane that is located on the underside of the base mat that extends upward

to one foot below grade of the exterior walls. This waterproof membrane was installed during construction to prevent infiltration of groundwater into the concrete structures.

Secondly the groundwater elevation in these areas is approximately 17 feet below grade. And only lower portions of the concrete walls and foundations are exposed to the groundwater.

Also the concrete is dense high quality concrete with low permeability and adequate cover. So by way of operating experience Kewaunee has only had minor in-leakage during the 36 years of operation.

So we believe for these reasons the concrete is not degraded due to the exposure of a slightly elevated chlorides in the groundwater. However Dominion is committed and will provide further assurance by taking a core sample in the aux building wall, below the groundwater elevation. This activity will test the chloride content in the concrete to validate that it is below the level to require it to cause degradation to the reinforcing steel in the concrete.

CONSULTANT BARTON: During that sample aren't you going to destroy the membrane, or did I miss where you're going to take the sample?

MR. AITKEN: We are going to go from the inside up, and we are going to go approximately - is it 18 inches, Charley?

MR. SORRELL: Yes, Charley Sorrell with Dominion, it's 18 inches.

MEMBER STETKAR: What is the thickness of the wall?

MR. SORRELL: Thirty inches.

MEMBER STETKAR: Why not like 26 inches to see if you can get a gradient for example in chloride concentration?

MR. AITKEN: And that is what we are intending to do is take that core and section it out and see if we do get that grading, as we get closer into the structure.

MEMBER STETKAR: If you don't find it there what does it tell you about the other 12 inches?

CONSULTANT BARTON: Nothing.

MEMBER STETKAR: I think I would go look for it close to the exterior surface of the wall.

MR. AITKEN: We'll take that as feedback, thank you.

MEMBER ARMIJO: Is there any information that you have from other clients or your own client regarding - confirming that the water proofing

membrane is still intact, not flawed, or torn. It's buried. So has there been any excavation for other reasons where somebody might have taken a look at that membrane?

MR. SORRELL: Yes, fortunately or unfortunately, Charley Sorrell with Dominion, there was an excavation performed on the west wall of the auxiliary building to bring in a dump bank and went up the wall and was going to core through the concrete above grade. And we were able to excavate about four or five feet of the top portion of that membrane. It was inspected, in very good condition, and no obvious degradation of that membrane.

MR. AITKEN: Dominion has scheduled to have the core removed and tested this year, so we are moving aggressively on this one. We are not waiting. Actually we are going to have the core taking next week. So we are moving on it.

(Simultaneous conversation)

CONSULTANT BARTON: Drill deeper.

MR. AITKEN: We will certainly take your feedback. Better than saying it was last week, I guess.

MEMBER STETKAR: This is not a hypothetical, we'll take it back and consider it for a

few months.

MR. AITKEN: Just to follow up on these issues, Dominion will continue to monitor the groundwater and the chloride levels do not decrease below 500 parts per million within the first 10 years of the period of extended operation, and we already made a commitment to do another chlorine.

MEMBER ARMIJO: Just to make sure that you know the root cause of this high chloride, in the other wells in the vicinity of the plant for whatever purposes, are these high chloride levels or relatively high chloride levels common or it the chloride level typically very low?

MR. AITKEN: Well, they are certainly below the 500 ppm. Charley has the numbers over there.

MEMBER ARMIJO: You know like city wells or private wells, what do they read?

MR. SORRELL: There are a total of 14 wells that were installed for the groundwater review, and there are eight wells that go through the plant as well as other wells around the facility. The wells that are in the grassed areas and not near the paved areas where there is salting are still relatively below the 500 limit considerably. The wells where you

have like a parking area and you get the salt piled up and the snow piled up have experienced higher readings.

MEMBER ARMIJO: So in these grassy areas, what is the number, a couple of hundred or 400 or what?

MR. SORRELL: We have readings that ranged at well 701 for example, less than 100, 702 less than 100, 705 is less than 300.

MR. AITKEN: But relatively low.

MEMBER ARMIJO: So you do pretty much have a good idea where the high salt concentration comes from?

MR. AITKEN: Currently we are doing this every quarter. We are trying to stay on top of it.

MEMBER ARMIJO: I'm from Nevada, the dry part of Nevada, we don't use too much salt down there. But that part of Nevada gets about two inches of rain per year. So I don't know much about desalting stuff. But is there anything better than chloride? Is there anything else you can use?

CONSULTANT BARTON: Sand.

MEMBER ARMIJO: Sand or ash or something like that?

MR. AITKEN: The station has evaluated

different applications of different materials with varying levels of success. So it's something we are still evaluating. It's a product that we tried a couple of winters ago with mixed reviews, so we are still pursuing it.

MEMBER SHACK: In Chicago we use beet juice mixtures now.

MEMBER STETKAR: A lot of buried cables, it works okay.

MR. AITKEN: Thank you for the question.

So that was the end of my discussion on the groundwater quality issue. Go to the next slide.

So I have a slide as I mentioned on the histogram of reactor trips at the Kewaunee station. As you would expect the frequency of trips has slowed through the years of operation. We have recorded our plant trips since the beginning of plant operation, and just to let you know we do monitor plant trips as a transient fatigue cycle kind of purposes.

Here is our chart. Typically you like to look for a knee, and the knee appears to be around 1980, '81. And as Steve alluded to earlier our last three years have been solid operating cycles for us.

(Simultaneous conversation)

MR. WILSON: During that period of time we

had a number of trips that were based on equipment reliability issues that had not been previously corrected including associated with a heat pump motor short, some what we called blind relays, relays that were undetectable but had failed so when we tested them on our nuclear instruments it caused a reactor trip, and also a breaker failure. And we have addressed those equipment reliability issues.

MEMBER STETKAR: What you have done though for projecting the number of cycles - correct me if I'm wrong - is you've taken the total number of accumulated cycles since day one and doubled it; is that right?

MR. AITKEN: Since the 2006?

MEMBER STETKAR: Up to 2006, whenever the line was drawn. And that's total since day one. You didn't do any screening to throw out any early operations or anything.

MR. AITKEN: We took a very conservative approach.

MEMBER STETKAR: Well, it's an approach. Other than the first three or four years where you might have a few extra, it looks like your trip rate has been relatively constant over about you know 25 years at least, or 27 years. And given recent - okay

the last three years it's been pretty small, but over the past five or six years there have been some wiggles and variations. So it's probably not unreasonable to double it. It might be a little bit conservative, but it's certainly not a factor of two or three conservative to do that given your relatively flat operating experience.

MR. AITKEN: Okay, if there is nothing else on this we will move on.

As I mentioned earlier we have four open items to discuss with the subcommittee that are currently reflected in the draft SER. What I will do is I will discuss the staff concern and then provide a summary of our response to this issue.

MEMBER STETKAR: I did have a question on the last one, shuffling notes here. In the safety evaluation report, I don't remember whether it was the audit report, one of the reports that I read, said that there were additional transients listed in the station records beyond those for which you do your formal counting. In other words there are certain categories that you count, and you throw one into one bin when it happens. What are those other transients? And how many of them? Can you give me examples of what they might be and how many of them you've

experienced and why they are not relevant?

MR. HOTCHKISS: Mark Hotchkiss for the applicant.

Yes, what that was referring to was transients that we track that were beyond the transients assumed in the Class I fatigue analysis. And some examples of those would be charging and let down transients. Kewaunee's vintage above the RCS is not Class I piping, it's B31-1, it's not ASME III. So there was no fatigue analysis. So the charging and let-down transients were not tracked for Class I purposes. So that is a charging let down.

Auxiliary heat exchangers such as RHR heat exchangers, excess let down, transients for those components; those are things we are looking at for 40 - 60 years as a TOL.

MEMBER STETKAR: Have you done your fatigue analyses on those systems? In particular charging and let down, because they can occasionally be subjected to some pretty severe temperature swings depending on what particular transient is. Isolate let down for example.

MR. HOTCHKISS: Yes, for the most part - for those non - for Kewaunee's basis, non Class I components we did not do fatigue analyses. We looked

at P-31-1 basis for limiting our thermal cycles. For charging in particular though, that was a location we had to actually apply environmental effects factors, so we did do a fatigue analysis for the charging loop nozzle.

MEMBER STETKAR: What is your projected 60-year CUF for that nozzle?

MR. HOTCHKISS: I have it here. The charging nozzle without considerations for environmental effects was point zero three. And with consideration of environmental effects was point four six.

MEMBER STETKAR: So you got a pretty good margin. There was certainly nothing that I read in the report that was close. Did you - any of your analyses for locations that are not specifically listed in the amendment show environmentally adjusted usage factors up in the point nine area or thereabouts, or projected greater than one?

MR. HOTCHKISS: When you say not included in the amendments, we had six locations we evaluated for environmental.

MEMBER STETKAR: And they are all --

MR. HOTCHKISS: They are all in the LRA. And they are all below one. And there are none that I

--

MEMBER STETKAR: For example the charging nozzle is not included in the amendment but you've done an analysis on it.

MR. HOTCHKISS: No, it is included. There is one of our locations, that was one.

MEMBER STETKAR: Okay.

MR. HOTCHKISS: A couple of locations on the reactor vessel.

MEMBER STETKAR: I thought I remembered reading something about an auxiliary heat exchanger or something that had design cycles for the reactor coolant hot leg sample heat exchanger would be exceeded prior to the period of extended operation.

MR. HOTCHKISS: For that particular item we did not perform a fatigue analysis for that component. We were conservatively considering that a TLA because the original design specification talked about 36,000 cycles for a 50-year life of that component. Here we are going to 60 years. We evaluated that as TLA, and we are just looking at cycles for that. We didn't do a fatigue analysis.

MEMBER STETKAR: Okay. Okay, thanks.

CHAIRMAN BONACA: So you are going to walk us through the open items?

MR. AITKEN: Yes, I am, sir.

So we go to the next slide. So the first item relates to the FatiguePro software. There is our submittal, with stress-based fatigue numbers for two of the NUREG 6260 environmentally assisted fatigue locations. The charging line nozzle and the pressurized surge line hot leg nozzle. Following the submittal of the Kewaunee application in August of 2008, regulatory information summary 2008-30 was issued in December. It was issued by the staff with concerns for nonconservatisms with the FatiguePro stress statistics fatigue approach. Subsequently the staff issued Kewaunee an RAI requesting that we make an appropriate adjustment and corrections regarding the use of the stress based monitoring and reevaluate the cumulative use factor. In accordance with the guidelines described in ASME Section 3-NB-3200.

We made a commitment to perform the reanalysis in our original RAI response, but we can report in the ASME Section 3 analysis for these two locations have subsequently been completed, and the results are acceptable for 60 years. The environmentally assisted fatigue evaluations were also determined to be acceptable for 60 years as Mark just mentioned.

MEMBER ARMIJO: What were the numbers? What were the usage factors for those two components?

MR. AITKEN: As Mark mentioned the first one on the charging nozzles of the CUF was .03. And the environmental number was .46 - I'm sorry, .75 - I'm sorry, .46 for the charging nozzle, and then for the surge nozzle CUF was .09, and the environmentally assisted fatigue number for 60 years was .75.

So we provided that information to the staff on June 1st, 2010, and it's currently under staff review.

That's all I have on that if there are any other questions?

The next topic is the work control process program. I need to provide you a little background no this topic as Brian alluded to in his opening remarks to set the stage for this open item so you have the benefit of understanding a significant change that occurred which impacted the overall review schedule for Kewaunee.

The Kewaunee work control process program that was originally submitted in the license renewal application was developed to model the fleet approach within Dominion. Based on the previous acceptance of this aging management program for Surry, units #1 and

#2, North Anna units #1 and #2, and Millstone's units #2 and #3. Following the sufficiency review, and during the course of the staff's technical review, several concerns began to surface for the submitted plant-specific aging management program.

So as a result in July 2009 a public meeting was held between Dominion and the NRC to brief the staff reviewers and NRC management on a change of direction. At that time we informed the staff that we intended to supplement the license renewal application to align with the GALL using the one-time inspection aging management program, which is referred to as M-32, and the inspections of internal surfaces aging management program, which is referred to as M-38 in the GALL, in lieu of the aforementioned work control process program.

We did indicate to the staff during that meeting that these two GALL programs would be bundled under one aging management program, maintaining the title of work control process. And that was to minimize several perturbations in the application.

We subsequently provided a supplemental response to the staff in September, 2009, reflecting the revised work control process, which now addressed the elements of those two GALL programs. We also

reclassified this work control program as a new program in lieu of a plant-specific program.

That's a little bit of background so you have the benefit of that.

CONSULTANT BARTON: So now you are doing these inspections for your work control program. What controls have you got on that program that somebody can't change a procedure on an item that is a one-time inspection requirement? How do you control on that? Because now you are going through your work process, and you can change those procedures. How do you control that?

MR. AITKEN: Well, it's essentially the two GALL programs. We are consistently with the GALL programs. We are just using the title of work control process programs, but that title was used throughout the application, and many times it really didn't change the intent of what - the change we were proposing didn't change the intent of a lot of the information in the application, so we are using those two programs. It's just that they are both bundled under the title of work controls. The controls, inspections, qualifications, are what they are as reflected in the GALL document.

CONSULTANT BARTON: Okay.

MEMBER ARMIJO: Are there any good features from your original work control process program that have been lost by virtue of converting to just using what the NRC told you to use?

MR. AITKEN: (Laughter) We feel there are, and we explained that to the staff in the public meeting. We discussed it. We understood the staff's concerns. But not all is lost.

MEMBER ARMIJO: Well, you know, what I'm getting at, you had this other process in place for many years. Your staff is used to it; you guys are used to it. It must have had some good features, and I just want to be sure that in converting to this other approach you don't lose some of those.

MR. AITKEN: Right, well, you know, one of the big things that we thought was a benefit of our version of the work control program was the frequency of inspections that we would continue to do during the period of extended operations, where one-time inspections would lead you to do one-time inspections, kind of a once and done approach, where we were going to continue to do it, not that we are not going to do that at the site, but under the auspices of license renewal. So that was one of the big things that we thought this program brought to the table.

We haven't deleted our work management program that we are going to use. So we will still use that. We will still get the benefit from that. What this does is overlay this additional process on that.

MEMBER SHACK: Okay.

MR. AITKEN: We are just trying to take maintenance that we do in the field, everyday, all the internal inspections that we do. We will train our maintenance staff to learn to identify aging effects, and then document on inspection sheets.

Now with that background, let's discuss a couple of remaining questions that the staff had in developing a draft SER. First the staff requested some additional information related to our intended sample methodology for the one-time inspection program portion of the work control program.

Next the staff requested some additional information related to the minimum sample size for the periodic inspections, and the inspection frequencies for the inspection of internal surfaces program portion of the working control program. So we had the M32 and the M38 portions of work control that we are talking about.

The work control process program is a new

aging management program. But in our last response to a request for additional information we provided a couple of examples how we were able to get back to aging through our maintenance activities, and how that information was identified and included in our corrective action program.

The staff requested additional verifications on this operating experience, and it was intended to be reflective of the new program.

And lastly the staff wanted clarification that the work control process program required enhancement, first to be implemented as a new program for Kewaunee.

CHAIRMAN BONACA: I didn't quite understand that. Go to bullet #2. Sample size for periodic inspections and inspection frequencies for inspections of internal surface. In this case what is the difference between what you were doing before and what the NRC wants you to do?

MR. AITKEN: What we were doing before was an opportunistic inspection approach for work control. And we went back through maintenance history over the last 10 years and looked at all our maintenance records to paint a picture of how often we have opportunities to go into the plant systems. And we

sliced that data by system, by components and by material, by environment. And what we were able to demonstrate is, we are out in the plant, we are doing maintenance everyday, and over the course of 10 years we are touching just about everything. So for the second bullet it's similar in nature, but it all doesn't require specific sample-based information. So I think the staff was looking for some additional information to help him or her understand the scope of what needed to be done.

Does that answer your question?

CHAIRMAN BONACA: Yes.

MR. AITKEN: So going to slide #25 which will provide an overview of some of the information we have provided back to the NRC. So we provided some additional information to the staff that described our approach in developing a sample size for the various materials and the scope of the one-time inspection portion of the work control AMP. The sample methodology will take into consideration the various materials, environments, aging effects, as well as plant specific OE for these in-scope licensing equipment.

Sampling approach is justified since one-time inspections are to be performed for components

that really are within the scope of the water chemistry programs. And the inspection results will provide additional assurances that unexpected aging is not occurring. So M32 is really just a validation of the effectiveness of our chemistry program.

For M38 we clarified that this aging management program is not based on a statistically determined sample size or a specified confidence level approach. As I described with M32, but more an opportunistic based inspection using the existing surveillance and maintenance activities implemented at the station.

So in response to this RAI we provided additional information to the staff that indicates that historically there have been sufficient internal surface inspection opportunities during surveillance and maintenance activities for the vast majority of the material and environment combinations. We have done an historical review over the last 10 years as I just described, and have a high degree of confidence that adequate inspection opportunities do exist.

In a situation where a material and environment combination has not been adequately inspected, then we will perform a deliberate inspection or inspections as required. Now as an

example, the material group of non-metallics and well water environment currently don't have any routine maintenance performance, so if we don't have an opportunity to have an inspection done prior to the period of extended operation, we will go out and schedule and do a deliberate inspection.

CONSULTANT BARTON: On what?

MR. AITKEN: On non-metallics and well water. That is just an example. We have gone back and looked through the grid, and we just don't have enough data there from the last 10 years, so we will go out and do that, we will schedule that inspection.

CONSULTANT BARTON: How much other inspections on your service water and in circ water where you have had - have you had corrosion, erosion and growth in those systems? I wasn't clear in reading the material that you really had that under control, and you had a lot of problems with your chemical injection system, and zebra mussels starting getting - and are you ahead of the zebra mussels or are they ahead of you at this point?

MR. AITKEN: That is a good question.

MR. HANNA: Tim Hanna for the applicant. We have a program where every time a service water system component is opened we document a visual

inspection of either the interior piping surface or the interior, the heat exchanger. We have seen microbiologically influenced corrosion in the service water system piping. We have not seen any corrosion in the service water system piping. We have done some routine readings to confirm in the high flow areas to confirm that we do not have erosion in the piping, and the MIC is generally confined to the leg sections and intermittent flow sections.

We have had erosion of copper heat exchanger tubing in the service water system, and we have instituted a replacement program for a safety-related units that have had problems with erosion in the past. And we have previously had problems with reliability of the chlorination system and that has been corrected through increased management attention. We developed performance indicators for the availability of the system, so now that is reported on, and the maintenance on the system gets a higher priority, and the reliability of the system has improved over the last several years.

CONSULTANT BARTON: So you are beating up on the zebra mussels, you are telling me?

MR. RUSCH: That is correct.

CONSULTANT BARTON: Okay, thank you.

MR. AITKEN: Just to finish up this topic, for the third sub-bullet there, we established a new commitment to provide the staff with operating experience related to the effectiveness of the work control process program within two years into the period of extended operation since it is a new program.

And lastly we clarified with the staff that the work control process program will be implemented and inspections completed prior to the period of extended operations.

So in summary our response to this open item was provided to the staff on May 13th, 2010. It's currently under staff review.

MEMBER STETKAR: Paul, the commitment 47, I recognize the gamesmanship of calling something a new program and saying you don't have any operating experience for that new program since it's called a new program. But you told us you have been doing this stuff for something on the order of 40 years now. How have you factored in that operating experience from what you've been doing in terms of adjusting inspection intervals or even what you sample for this now new program that is perhaps somewhat more structured?

In other words 40 years of operating experience from what you've been doing doesn't seem to be irrelevant simply because you've reclassified a program now as a new program.

MR. AITKEN: I mean I would say at a high level we do inspections, we find the results, we enter them into our corrective action systems, we do extended commission reviews, extent of cause. And if we need to broaden our review or inspections then we do so through that process.

MEMBER STETKAR: But for example I mean if you go back and look at the effectiveness of your inspections or the opportunistic checks or whatever you have been doing, that information can help you organize areas to focus on or experience in places that you haven't been working, and I'm curious to see how you have done that in kind of tailoring this new program.

MR. AITKEN: Well, it is a new program, and so that review looks at, and evaluation of the data is really a function of the license renewal coordinator as we move forward into the period of extended operations.

MEMBER STETKAR: Maybe I will ask the staff. Thanks.

MR. SCACE: But I think what Paul indicated is, we are using that experience and demonstrating the opportunistic if you would views. And those are conditioned based on experience as you'd expect over 40 years. So some inspection frequencies we do more often, and will continue to do that. They will now be documented under this new program, but we are not going to start at ground zero because we have a new program. So a major part of this other than those we determine we haven't had sufficient opportunistic opportunities, that program and that experience will continue with our inspection.

MEMBER STETKAR: Okay, thanks, that helps a little bit, thanks.

MR. AITKEN: Next slide.

So the third open item relates to steam generator divider plate cracking. On this item the staff requested additional information from Kewaunee related to the materials of construction of the steam generator divider blade, and the weather cracks in the alloy 600 divider plate could propagate into the base material of the channel head or into the tube sheet platen.

If we determined that this condition was likely then the staff requested that the details of an

inspection be provided for review. As Brian mentioned the request was based in part on I believe French OE with the divider plate cracking.

MEMBER STETKAR: Paul, before you go back to the other slide, the last bullet on there, it says recent - oh recent foreign operating experience. I'll ask you now before you get into the materials things that I don't understand anything about, you replaced the steam generators in 2001. In 2006 apparently you discovered a number of foreign objects in both your steam generators. All I know is what I read in the reports. Five foreign objects in steam generator A and nine foreign objects in steam generator B.

This has nothing to do with the topic of what you are talking about here as far as primary water stress corrosion cracking, but at least the steam generators - and I was going to ask you later anyway so I might as well do it now. What were they? Where did they come from? And do you have a loose parts monitoring system?

MR. HANNA: Tim Hanna for the applicant. We do have a loose parts monitoring system. All of the parts that you are referring to were on the secondary side of the steam generators, and they were very small remnants for manufacturing such as weld VBs

or very small machine turnings. And they were either removed from the steam generators or evaluated as acceptable for continued service, due to the very small volume of the material.

MEMBER STETKAR: So they were - you actually determined that they had been in there since the original installation?

MR. HANNA: That is correct.

MEMBER STETKAR: Okay.

CONSULTANT BARTON: Do they have a loose parts monitoring system?

MEMBER STETKAR: It's not really a part. Loose parts monitoring typically picks up more stuff on the primary site. It's pretty messy out on the secondary side.

MR. AITKEN: Okay, so this issue remains under review by the various experts and technical groups in the industry along with the NRC staff. A meeting was conducted just last week between the NRC and the industry where several people were trying to understand the concern and ascertain what is the best path to resolve this item not only for Kewaunee, but for the other affected plants in the United States.

Dominion remains active in these forums, and if there are any new requirements promulgated to

the industry, then Dominion will evaluate the industry recommendation like the other affected plants and do the right thing.

In response to this open item we concluded that the condition described by the staff is unlikely for Kewaunee for the following reasons. First, the steam generators are relatively new, they're not quite 10 years old as Stew had mentioned. They are not likely to experience cracking with this limited service life.

Next, although the divider plates are alloy 600, the divided plate assembly welds are made from alloy 52/152 weld metal which is inherently resistant to cracking caused by PWSCC.

Also we believe there is sufficient data from the industry resource to support the conclusion that PWSCC cracking stops when nonsusceptible materials are encountered.

There is no U.S. or international OEs that Dominion, EPRI or Westinghouse is aware of indicated that cracking of the divider plates has ever propagated into adjacent tube sheets of channel heads.

So based on the above Kewaunee concluded in its response to this open item that an inspection program is not warranted at this time. And that

response has been provided to the staff as of July 22nd, 2010, and is currently under review.

And our last open item, relates to the ongoing issue related to buried piping and underground components. First the staff requested that Kewaunee identify systems with components that are in a buried or an underground environment. The staff also requested that we provide any updates related to operating experience with the buried piping that was not included in our application submittal.

First I'd like to address the equipment located in an underground environment, which could be within vaults or chases, and exposed to air on the external surfaces. Kewaunee has very limited equipment in this category, just a few feet of fuel oil transfer piping for our diesel fuel oil system, and a couple of fuel oil transfer pumps. This equipment is managed for the effects of aging by the visual inspections performed in accordance with the external surfaces monitoring program on a period frequency.

The remaining components that are in a soil environment are managed for the effects of aging by the buried piping and tank inspection program which I will discuss here in the next few slides.

MEMBER STETKAR: Paul, you talk about buried piping, the general stuff extends also to so-called underground piping. There are pipe chases, pipe ducts, things like that. What in scope piping is in that classification? Do you have any?

MR. AITKEN: Well, that is what I mentioned. We just have a few feet of fuel oil piping, and it's very limited in scope.

MEMBER STETKAR: Service water piping doesn't go through an underground - nothing? It's above ground?

MR. AITKEN: No, it's direct buried.

MEMBER STETKAR: Oh, direct buried.

MR. AITKEN: Next one we'll talk about that.

MEMBER STETKAR: Okay, thanks. I thought it was in a tunnel.

MR. AITKEN: All right, so here's a list of systems that fall in the category of being in a direct buried or soil environment. As you can see these systems are not radioactive fluid process systems. At Kewaunee all piping in tanks that do contain radioactive fluid are located in a Class I structure. It's one of the benefits of being in the Midwest.

We have listed the systems and the number of inspections that we have committed to along with the frequency of the inspections on this slide. For your information each piping inspection will consist of a minimum of 10 linear feet. So I'll try to walk you through the information on the slides.

MEMBER STETKAR: I'm sorry, I'm still being dense. I don't see service water piping listed here anywhere.

MR. SCACE: Service water piping is in a - you could call it a tunnel but it's actually part of the structure. It's a walkway.

MEMBER STETKAR: It's all accessible, visually accessible?

MR. SCACE: Yes, absolutely.

MEMBER STETKAR: Thanks, that's what I thought I remembered. I wanted to make sure it was all visually accessible and that it didn't go through a section that got real small.

MR. SCACE: Not, it's all visually accessible.

MR. AITKEN: So we have approximately 200 feet of coded and red carbon steel circ water piping as well as approximately 15 feet of coated and wrapped stainless steel circ water piping. We will perform

one inspection of each of these material environment combinations prior to the period of extended operation, and then again in the first 10 years thereafter. So as total of two inspections prior to and then again two more inspections in the first 10 years thereafter.

We have approximately 500 feet of diesel generator fuel oil piping that is coated in wrapped carbon steel. We will inspect this once prior to the period of extended operation, and then once again in the first 10 years thereafter.

We have three fuel oil storage tanks, two for the emergency diesel generators and one for the tech support center, it's a standby generator, and we have committed to inspect one of the three storage tanks prior to the period of extended operation, and then inspect another tank while in the first 10 years.

CONSULTANT BARTON: None of those fuel oil storage tanks have been inspected to date?

MR. AITKEN: Not externally but internally they have?

CONSULTANT BARTON: Internally? All right. Now you've got these things strapped with external straps that are uncoated. Have they ever been looked at?

MR. AITKEN: No, but they will be as part of the tank inspections, as we remove the soil they'll be exposed.

CONSULTANT BARTON: You will look at the straps, the hold downs?

MR. AITKEN: That's correct.

Lastly we have approximately 2,350 feet of coated ductile iron for our fire protection system. We have committed to perform three inspections prior to the period of extended operations, and then three more inspections in the first 10 years thereafter.

We feel that this proposed inspection scope and frequency will provide reasonable assurance that the effects of aging will be adequately managed for the period of extended operation.

MEMBER STETKAR: You have to replace some potable water piping. Is the material in the potable water piping the same as your fire protection piping?

MR. AITKEN: Yes, it is. We did it as an extended condition on our potable water piping failure, we did an extended condition on our fire protection piping in 2007. We actually excavated. The results were acceptable. The pipe was in good condition. It's a pretty big trench we've got to dig to get down to it.

CONSULTANT BARTON: This piping you are showing us is what now?

MR. AITKEN: That's fire protection piping.

MEMBER ARMIJO: That's ductile cast iron coated with some - wrapped and coated with some material?

MR. AITKEN: That is correct.

MEMBER ARMIJO: And how about the inside, what does it look like inside? Is it rusted?

MR. RUSCH: Jim Rusch for the applicant. That is a concrete lined pipe, so it would have a concrete liner inside. I don't believe that we have ever inspected the internals of that. They haven't sent a camera in.

MEMBER ARMIJO: Do you use any kind of galvanic protection like anodes for your tanks or piping systems?

MR. AITKEN: Yes, we do, the circ water system piping and all but about 100 feet of the diesel oil fuel oil piping is cathodically protected. The fire protection piping is not cathodically protected.

MEMBER STETKAR: So this was done in 2006, `7?

MR. AITKEN: 2007.

CONSULTANT BARTON: This picture apparently is in the winter time. What is all that white stuff on the top of the picture? Is that just soil? Or is that something on it, all that stuff?

MR. RUSCH: Jim Rusch for the applicant, that would be the sand, the backfill, that was near the piping. You look at the backfill for small uniform size backfill. So they would have just piled that off to the side.

CONSULTANT BARTON: Okay, I was just making sure it wasn't dried salt from the - (laughter). Thanks for clarifying that.

MR. AITKEN: Okay, that is all I have on that slide. If there are no other questions we'll move on.

CONSULTANT BARTON: I've got a couple of questions.

You committed to a non EQ inaccessible medium voltage cables, to inspect manholes for water collection every two years. And I was wondering how you came up with every two years. On a lot of applications I've seen after every rainfall season, after snow melts or something, they go down and look at manholes. All I see is every two years.

MR. AITKEN: At least every two years,

that's correct. Since 2006 we've been in five times, and the water level in there is an inch or two. As I mentioned earlier the groundwater level is 15 or 16 feet below that manhole.

CONSULTANT BARTON: Do you have any sump pumps?

MR. AITKEN: There are no sump pumps, and we don't see any indications on the concrete of any water staining or coming in from the duct nodes.

CONSULTANT BARTON: No experience of any wetted cables in any of those manholes?

MR. AITKEN: That's correct. The water level is two feet below the cables. It's not to say if we had a 100-year flood and we saw any water in the yard, keep in mind where that manhole is and where the lake is, it's a significant drop off. So we really don't anticipate a problem. So we were comfortable making the commitment of at least every two years. But if we go in and we find something then we will adjust that frequency.

CONSULTANT BARTON: Okay, thank you.

The other question I've got is, you didn't mention anything about your refueling cavity leak. Can you tell us what that's all about and what you are doing about it?

MR. WOOTEN: David Wooten for the applicant. The refueling cavity leak, we do have some leakage. And it presents itself as staining and sort of a damp wall. There is no real flow, no measurable flow that we can actually measure. It presents itself in two locations, on biological shield wall underneath the cavity, and also over on one of the steam generator output vault. And this upcoming outage we are going to do in some, an interim approach to try to identify the leakage, using vacuum box testing and NDE and some visual examination. And then we are also going to use Instacoat on the lower cavity area to try and isolate where the leakage might be.

CONSULTANT BARTON: You haven't seen any drippage or anything on any metal surfaces or anything as a result of this leak? Or has this leak increased any over the years since you've first seen it?

MR. WOOTEN: The leakage was first identified in 2006, and again in 2008. And there has been some slight puddling, some slight buildup of boric acid. The components that it has been on have been cleaned off, and we are monitoring it as we go.

MR. AITKEN: We find that the leak doesn't really manifest until several days after the cavity is filled. I think it was 16 or 17 days, Steve?

MR. SORRELL: Correct.

MR. AITKEN: Before the leak actually --

CONSULTANT BARTON: Yes, if it's through a line someplace, and gets through the concrete, I had a similar leak and I know they are hard to find. But it looks like you got a program, you are going to start looking and see if you can identify it.

MEMBER STETKAR: One of the things I recall, and correct me if I'm wrong, you are also - you also have a leak area in the spent fuel pool; is that correct?

MR. WOOTEN: Correct, and the leakage out of the spent fuel pool presents itself in two areas. One is through the leakage collection system, through all of the 10 zones, about a liter a day. It also presents itself as some deposits on the drum room ceiling which is right below the spent fuel pool

MEMBER STETKAR: So you are going to take a core sample in that ceiling, right, to try to evaluate the effects of possible boric acid effects on rebar for example; is that correct?

MR. WOOTEN: That is correct. We are going to take two bores, one would be a petrographic core sample, and that would be right on the crack, and then we are also taking a compressive core sample a

little bit off the crack to determine integrity of the concrete, and also exposed to rebar, so we can perform an inspection on rebar.

MEMBER STETKAR: You are going to use those results, I think I read somewhere, to infer the status perhaps inside the containment, the concrete rebar inside the containment. What is the normal boric acid concentration in the fuel pools, spent fuel pools?

MR. WOOTEN: About 2,600 ppm.

MEMBER STETKAR: What is the normal boric acid concentration in the refueling cavity when you are refueling?

MR. SCACE: During refueling it's greater than 2,500 ppm.

MEMBER STETKAR: So they are --

MR. SCACE: They're comparable.

MEMBER STETKAR: Okay, that's what I was looking for, thanks.

CHAIRMAN BONACA: For how long have you had a leakage?

MR. WOOTEN: For the spent fuel pool there is some indications back in the early `80s through the leakage collection system. As far as on the drum room ceiling, 2007 is when we first notified.

CHAIRMAN BONACA: Okay, thank you.

MR. WOOTEN: And like I said, it presents itself, we'll clean it off and four or five months later it presents itself again. It's a real slow process. But it's not wet. It's just sort of - water comes out and evaporates.

CHAIRMAN BONACA: Okay, thank you.

CONSULTANT BARTON: You took an oil sample in May of 2009 on on 1V control room air conditioning chiller pump, and there were suspended particles when you looked at the oil. And you did the analysis. And they were identified as coming from the sealant tape you used on the pipe plug, am I right. Now it wasn't clear, and this is in the SER I saw this, it wasn't clear the corrective action that you guys to prohibit the use of this sealant tape on pipe lugs. And I don't know if you are setting yourself up for more tape dissolving and coming apart in your oil samples on rotating equipment, that's something you may want to follow up on and prevent a problem down the road. Because I'm not sure, you know, you stopped using that tape on these type plugs which could contaminate the oil.

MR. SCACE: I will share that insight, that suggestion with our maintenance personnel to make

sure we have the proper controls in place with respect to sealant tape.

CONSULTANT BARTON: Okay, thanks.

MEMBER STETKAR: Last one, I know we are running over. Emergency diesel fuel oil day tanks, there was some discussing about sampling fuel oil in the day tanks, condition of the tanks and so forth. As I understand it there is a - the suction line inlet-outlet line to the diesel comes off a three-inch riser off the bottom of the tank, as best as I can understand, so that there is some volume of fuel in the tank below that riser. Do you have any idea how much?

You say that you sample regularly from the fuel oil line to the diesel, and I was curious when you do that sample. Do you normally pull the sample before you start the diesel, or do you pull the sample after the diesel is turned on and you've had a chance to stir up the contents of the tank a little bit? I'm curious about what contaminants might be in that tank that you did not find out about from a sample, and if you are only pulling a sample from that line for example when that tank has been stagnant for 30 days, or however frequently you test the diesel, you wouldn't know what was down there in the bottom.

MR. AITKEN: We will have to look into that.

MEMBER STETKAR: Bring it back.

MR. AITKEN: Okay.

CHAIRMAN BONACA: Any other additional questions at this time?

MR. WEBSTER: I'm Bill Webster with the applicant. I just wanted to answer your question about the alert. What we did for the SAM analysis, we went back and used the standard for steam generated tube ruptures. So it's got to be incorporated in the induced tube rupture into the mode and that increased the lighting.

MR. AITKEN: I just had one last slide to go through, Mr. Chairman.

Kind of following up on the buried pipe, Kewaunee is keenly aware of the issues that have challenged the industry related to buried piping and the possibility of degradation going undetected. Here are some of the ways that our Kewaunee staff remains engaged with the industry events related to buried piping. Kewaunee as well as the other units within the Dominion fleet have committed to the NSIAC initiative, and NSIAC is the Nuclear Strategic Issues Advisory Committee through NEI, where the chief

nuclear officers gather and make policy for the industry.

NSIAC initiative ensures that risk-significant buried piping and other buried piping that are important to plant operations and/or nuclear or environmental safety be periodically monitored for degradation. The implementation of this program is also being coordinated with a requirement stemming from the licensed aging management program.

Station staff continually evaluate external operating experience through a corrective action program as I mentioned earlier for issues that are applicable to the processes, programs and equipment at Kewaunee. Also we have a fleet lead as well as a site lead in place at each of our Dominion stations where program information is exchanged including industry operating experience through monthly working group calls. This information that is presented would cause a change to the buried pipe program, that would be initiated through this working group.

And lastly Dominion is an active member of the EPRI buried piping integrity working group where information is shared on an ongoing frequency. There was just a meeting two or three weeks ago down in

Atlanta, and we were a part of that.

So a response to the buried pipe issue has been provided to the staff on July 22nd, 2010, and remains under review.

So I believe that is the end of our prepared remarks, and if you have any followup questions, we'd certainly like to answer them for you.

CHAIRMAN BONACA: Questions?

If not, we will take a break now, and resume at 10:30.

(Whereupon the above-entitled matter went off the record at 10:13 a.m. and went back on the record at 10:30 a.m.)

CHAIRMAN BONACA: Okay, let's get back into session, and now we have the presentation of the SER on the part of the staff.

NRC STAFF PRESENTATION

MR. HOLIAN: Yes, thank you, Chairman. Brian Holian again. I'll just start off. We did add a couple of other people to the table from license renewal staff. I previously had mentioned Jay Robinson as the branch chief. Ms. Caroline Tilton is a senior inspector our of Region 3, John Daly the PM. To John's right is Allen Hiser. He's the senior level adviser in the Division of License Renewal. He

has had background in provision of component integrity, and in particular Allen is there for questions maybe on the steam generated divider plate and other issues. At his right is Dave Pelton. He's another technical branch chief in the Division of License Renewal, and was also involved in particular on the work control process review, and his staff.

I wanted to introduce one other person in the back of the room. He's not always here, but Jim Gable is a senior inspector from Region 3, in the back room there standing up. He is a Division of License Renewal employee, and we use him out of Chicago office. He was on the license renewal audit for Kewaunee, quite a few of our audits he goes out on. He's been a long-time, 24-plus-year mechanical engineer out of Region 3. Did a lot of work on Davis-Besse for two or three years, and we pick him up as one of our employees, and he's here today and I wanted to recognize that.

With that I'll turn it over to John Daily.

MR. DAILY: Thanks, Brian.

Good morning. My name is John Daily. I'm the project manager for the Kewaunee Power Station license renewal review project. We will discuss the

staff's review of the Kewaunee license renewal application as documented in the Safety Evaluation Report with open items. Next slide.

We have an outline of today's presentation as shown here. First of all an overview of the Kewaunee Power Station license renewal review, and we will cover a summary of the results from SER Section 2, the scoping and screening reviews. Next we will do a presentation on the results of the Region 3 license renewal inspection.

Then we will cover a discussion of SER Section 3, the aging management program and AMR results along with the open items that resulted with them.

And finally a discussion of topics out of SER Section 4 the time limited aging analysis.

Most of the information on this overview slide was already covered by Dominion in their presentation so we won't be repeating it all again, it's just here for reference purposes. You can go to the next slide.

Staff review teams conducted audits and inspections for the application during the periods as shown here on this slide of audits and inspections. The main aging management program audit was conducted

June 9th through 12th of 2009, and it was conducted at the Kewaunee site. Then later on during October, during the week of October 19th and 20th, we conducted an audit of the revised work control process aging management program. In addition Region 3 conducted its regional inspection in the timeframe of August to September, 2009, and of course their inspection results will be presented shortly.

In preparing the safety evaluation report, and in addition to the audits and inspections we already mentioned, the staff conducted in depth technical reviews and issued over 240 requests for additional information to which the applicant has responded with further information.

As Dominion had covered during their presentation, one issue in particular that impacted the project schedule concerned Dominion's designation and use of its work control process maintenance program. Of course they have covered most of the details there. We did mention that as a result of the resubmittal in answer to the staff's concerns in September of 2009 the schedule required a revision, and of course we added two months on to the review schedule in order to accommodate this new information that had been submitted. The SER with open items was

issued to the applicant on July 16th, 2010. As an SER it contains four open items which are summarized here. The use of Fatigue Pro software and metal fatigue calculations; concerns with potential primary water stress cracking corrosion in the nickel alloy steam generator plates, divider plates. Number three was concern incorporating recent operating experience for buried and underground piping and tanks. And finally some issues that were identified in the revised work control process program.

Of course we will be covering each one of those in detail later on in the presentation.

This slide presents our summary of the results for SER Section 2. Section 2 covers the structures and components that are subject to an aging management review, along with the results, the subsections which we will summarize briefly here below. Under Section 2.1 which is the scoping and screening methodology reviews, one of the things to note here is that as a part of this audit, the scoping and screening audit, the staff utilized for the first time an independent key word search of the applicant's condition reports, corrective actions, operating experience and so forth, all of that data. We used that keyword search as a method of identifying

material and aging effects that could be of interest. The results from this search were then passed on to the aging management program audit staff for their use in determining whether the applicant has considered all of the relevant age related issues during the development of their applicable AMPs.

And then the conclusion to Section 2.1 is shown here. We did find that the methodology was consistent with the requirements of the rule, 10 CFR 54.4, and 54.21.

The plant level scoping results which were conducted in accordance with Section 2.2. The systems and structures finding was that they were within the scope of license renewal and they were appropriately identified following the request for additional information on things that were submitted in accordance with 10 CFR 54.4.

And then the actual scoping and screening results which are covered in Section 2.3 through 2.5l we found that the SSCs within the scope of license renewal were appropriately identified in accordance with, again, the rule, and those subject to an aging management review were appropriately listed in accordance with 10 CFR 54.21(a)(1).

Next slide. At this point Caroline Tilton

will present a discussion of the Region 3 license renewal inspections.

MS. TILTON: Good morning. My name is Caroline Tilton, and I am the team lead of Kewaunee's license renewal inspection.

For the last year Kewaunee has been in the licensing response column of the action matrix with all cornerstones green. For these inspections we follow inspection procedure 71002. This was a two-week inspection conducted the week of August 17th and August 31st, 2009. Our inspection team consisted of five inspectors and a regional ops server.

We performed both parts of the procedure, the scoping and screening, and the aging management program review.

The inspectors performed walkdowns on portions of 10 systems. These walkdowns were intended to determine the acceptability of the scoping boundary; to observe the current condition of the structure, systems and components; and to assess the likelihood that the proposed aging management program would successfully manage aging effects.

For the scoping and screening section the team performed walkdowns of selected systems. Overall the scoping and screening drawings had adequate

division between nonsafety and safety related. There were a few instances in which minor discrepancies were identified between the drawing and the actual plant configuration. These instances were adequately addressed and corrected by the applicant.

MEMBER SHACK: There was some discussion in the report of this notion of a collapse envelope which seemed to be a nonstandard kind of terminology. Was that sort of reviewed and found that it was just their terminology for what was an acceptable practice?

MR. DAILY: That did come up during the scoping and screening audit, and we got one of our staff members here who can explain that for you.

MR. ROGERS: Good morning. I'm Bill Rogers. I'm with the Division of License Renewal. We considered that during the scoping and screening methodology audit and our review associated with that. I did note that that term was new to me, I hadn't seen that before, and I brought that to the applicant's attention. So what we did when we were on site, we discussed how that fit into their process. And we actually went and walked it down.

So what that related to was essentially tanks at floor level atmospheric pressure, so they would just have some static head, and it would be able

to leak basically below the fluid level in the tank.

So we took one of these examples, we walked down the room, we looked at the location of the tank, the location of any safety-related equipment that might be affected. And then of course the way the equipment was situated such that there would be mitigative features in between the potential fluid path and the --

MEMBER SHACK: Oh, so this was solely for tanks?

MR. ROGERS: Tanks at atmospheric pressure. And if I'm correct they were all at floor level. So it was unusual enough that we walked it down, looked at it. We discussed it with the applicant. They considered that the term, collapse envelope, was maybe a refinement of the ideas contained in 95.10 as opposed to an exception, and when I read the response and applicant, concerning the walkdown and the discussions, I found that to be acceptable. But I did feel it was something that we needed to look at.

MEMBER STETKAR: I am kind of a simple minded person. I have a tank right here. It looks like a coffee cup at atmospheric pressure sitting on the floor. What is the collapse enveloped for this

tank sitting on the floor look like? What is it?

MR. ROGERS: Here is what our conclusion was on that. If you just got rid of the tank, where would the fluid go? The enveloped, you would start with the tank leaking and whether it would have the potential to spray on any associated equipment, and if the tank were to fail completely how would the entire contents of the fluid affect any equipment in the room.

MEMBER STETKAR: Okay, so it's not just strictly a submergence, volumetric submergence. It has something to do with splashing or spray?

MR. ROGERS: No, it has to do with volume. So one thing we did make sure during the walkdown, we reviewed the position and the mitigating effects. There are berms and platforms for the safety related equipment, and the applicant had looked at that and we had looked at that, you could make a reasonable assessment that the volume wouldn't affect the equipment in the room.

So if you go from A to B, from a small leak to a release of a volume, it seemed like it had been bounded either way, so we accepted that. But --

MEMBER SHACK: It could include the effects of both the spray and the flooding?

MR. ROGERS: Yes, it did. Because actually the applicant addressed in their response to the RAI that they considered a through-floor distribution of the fluid, all of that had been considered.

MEMBER SHACK: Okay, thank you.

MR. ROGERS: Okay, you're welcome.

MS. TILTON: For the aging management program the team reviewed a sampling of 24 out of the 34 aging management programs. This would have included programs implementing documents and procedures; lock downs; and interview of plant personnel.

As a result of our aging management program review, several issues were identified. Related to the buried piping and inspection program, the inspectors found that a procedure triggered an engineering evaluation to be performed when the measured wall thickness was less than 75 percent instead of the standard 87.5 percent. This 75 percent acceptance criteria could potentially be nonconforming to the design basis.

The applicant produced a new procedure intended to replace the existing procedure. However it was still in draft status. The applicant initiated

corrective actions, determined that the existing procedure had not utilized the potentially nonconservative acceptance limits, and placed adequate restrictions for its use.

Related to the compressed air monitoring program, there were two areas identified where the applicant --

MEMBER BROWN: Before you leave that, could that 75 percent limit, could that be used for any other evaluations? Or this a go forward type procedure? Did I phrase my question properly?

MS. TILTON: Yes, I don't understand.

MEMBER BROWN: I'll try again. You said they had identified the incorrect wall thickness that they were using 75 percent as opposed to 87.5 percent or something.

MS. TILTON: They actually never used the 75 percent, and the procedure said that 75 percent is an acceptance criteria.

MEMBER BROWN: But they had not used this procedure for anything up to this point anyway?

MS. TILTON: Correct.

MEMBER BROWN: Okay, thank you.

MS. TILTON: Related to the compressed air monitoring program there were two areas identified

where the applicant intended to take exceptions to the GALL that were not noted in the application. These two exceptions were, performing air quality measurements, and trending of air quality sampling result. The applicant agreed to amend the application to include these two exceptions with the appropriate justification.

Related to the external --

MEMBER STETKAR: Caroline, let me stop you on the compressed air. I had a couple of questions. I notice they had three instrument air dryers, 1A, 1B and 1C, and for some reason instrument air dryer is excluded - 1B is excluded from the scope of license renewal, and the justification for that seems to be that their Appendix R fire response procedures say that you go isolate instrument air dryer B when you know you have an Appendix R fire event. The instrument air system during normal operation doesn't know anything about Appendix R fires, so I'm curious how anything to do with Appendix R fires has to do with the use of that particular instrument air dryer to maintain the air quality during the 366 - I'm sorry, 365.25 days per year when you don't have Appendix R fires, given the fact that they are pretty much less frequent than one per year, how can you

justify excluding that air dryer?

MR. DAILY: That may involve the actual classification and reasons for the dryers themselves, and maybe our staff or maybe Dominion might like to explain how the dryers are classified and why that was that way.

MR. RODILL: Yes, Ben Rodill with Dominion. Basically the air compressors and the dryers are nonsafety related. There were two compressors that were credited for Appendix R, and either on dedicated or alternate shutdown. And we included conservatively all the compressors in scope. And then one dryer was excluded from scope on the basis that our procedures clearly have enough time to allow operators to isolate the dryer that is not credited for that event.

MEMBER STETKAR: If I go to the plant and just randomly walk in at any given time, what is the likelihood that air dryer 1B will indeed be in service?

MR. RODILL: I am not quite familiar with the operation of the dryers from day to day.

MR. WOOTEN: Dave Wooten from the applicant. We typically just operate air dryer Charlie. Air dryer alpha and bravo and just used as

backups.

CHAIRMAN BONACA: I didn't hear what you said.

MR. WOOTEN: We have three air dryers, alpha, bravo and charley. Typically we only run air dryer charley, and air dryer bravo and alpha are just used as backups.

MEMBER STETKAR: You didn't quite answer my question, because having quite a bit of experience with air systems and air dryers, they are not the most reliable pieces of equipment in the world. So although charley might be normally lined up, I suspect that alpha and bravo indeed are operating some fraction of the time. And I was asking specifically for what fraction of time bravo might be in service.

My point is that if it's normally operating to maintain quality of the air system, and if the fire protection program takes credit for the availability of air to operate certain pneumatic devices during a fire event, the status of air dryer bravo indeed has some effect on the quality of said air. The effect depends on how often it's actually operated, but indeed it affects the quality of that air system.

So it's not clear to me simply because at

the point of a fire you can go valve it out, that it's historical performance hasn't had some effect on that air out in the lines, way out where the pneumatic devices exist. So I was really curious about why it should be excluded, particularly since you have included all three compressors.

MR. DAILY: So particularly if that air dryer were on service when the event happened --

MEMBER STETKAR: Or had been in service 50 percent or 33 percent of the time for the last 25 years and it had problems, the problem with air systems is contaminates tend to accumulate way out at the ends of things, for example if that air dryer wasn't doing its job and oil and moisture had been getting through accumulating on for example solenoids or air operated valves, they might not work. Even thought it might not have been in service even when the fire happened, or you might have valved in a really good air dryer when the fire happened, the air system doesn't know about that historical operating experience.

MR. DAILY: I think that is something that we may need to look into and discuss with Dominion and find out what would be the proper dispensation for that air dryer.

MR. HOTCHKISS: Let me just make one maybe clarification. This is Mark Hotchkiss from Dominion. The air dryers are credited as part of a compressed air monitoring and quality control system. They certainly are maintained at the plant, and continue to operate when necessary, and operate and function correctly. And as far as the compressor monitoring program, we sample the air, we maintain a quality of the air itself which would lead us back to air dryer problems.

Now from a scoping license renewal scoping standpoint the air dryers did not meet the criteria to be in scope; in other words they were not safety related, and they were not a support system necessary for safety related equipment to function. However for the Appendix R a certain air dryer did meet that scope and criteria, so that air dryer which was, what, alpha, two of them met that criteria so they are in scope. But I think your question is related to compressed air quality, so that is the point, our program maintains the compressed air quality by sampling.

MEMBER STETKAR: Let me - because that question is about air sampling also and bypasses the air dryers. Your air quality sampling point is taken

off the header after the dryers, so you know the quality of the air at the main distribution head. Do you do any air sampling way out at the ends of the lines so you know for example the moisture or oil content of the air out at the end users?

The concern is, I used to operate at a plant that had air problems, because we had air dryer problems, and they were bypassed quite frequently, and oil and moisture migrated down the length of our air lines, and they tended to varnish in place a lot of solenoid operated valves; you basically cooked the oil and made it a varnish. So unless you know the quality of the air or have some means of determining that the pneumatically operated devices are doing well, just sampling the air quality at the outlet of the dryer doesn't necessarily tell you much especially if you are bypassing the dryers pretty frequently.

So the question on air sampling is, do you do any end-use air sampling or at least have a regular blowdown program to blow down the lines at the end users?

MR. AITKEN: Paul Aitken from the applicant. We don't have that information right now, so we will have to get back to you on that.

MEMBER STETKAR: Okay, thanks. I

recognize the licensing concerns and the restrictions on Appendix R and all of that stuff, but ultimately what we care about is what is the quality of the air at the end users when they need it. And in license renewal space if the only end users are a certain subset of air operated devices, I'm assuming there is some valve some place, well that is fine. But the historical performance of the system up to that point determines what that quality is.

MR. PELTON: Let me just leave you with two thoughts, too. When we look at the compressed air monitoring program, it was a program that was largely built to attempt to take credit for an existing series of generic letters, part of which were based on some of the experiences you mention, the varnishing effects, system in leakages and other events that have contributed to failures of the instrument air system to operate appropriate. So as licensees were implementing programs to address those generic events, when we looked at this program and said, well, if you take credit for the actions you have already put in place and just refer to it by, oh by the way it's also an aging management program and it meets the elements of the generic aging lessons learned report, all is good. Alternatively the passive and long-lived

functions of these systems depending on which portions actually are within the scope of license renewal, is largely as a pressure boundary. So it would be pressure boundary capability at piping in valve bodies, which can be effectively managed through using our internals inspection program. So it's not unusual for a licensee or an applicant in this case to propose, so I guess - John made a great point, which is we can further explore and make sure that we inform you folks on what are the efforts right now or the actions that licensees are supposed to have in place to address the overall performance and ability of the system to function when called upon, versus the aging management perspective of the in scope portions. We can get that.

MEMBER STETKAR: Okay. One thing before I give up on the compressed air stuff, I was a bit disturbed by a quote in the SER that it talked about concerns about bypassing - or the air dryers and bypassing the air dryers, and the staff --- here is a quote, the staff finds the applicant's procedure including the establishment of the pressure setpoints to bypass the dryers is adequate to manage the aging effects because the bypass of the dryer with the high differential pressure value greater than the setpoint

can mitigate the potential degradation of air quality and its adverse effect on the degradation of the components in the system.

Bypassing an air dryer is the worst thing you can do for air quality. The more you bypass an air dryer, the worse the air eventually gets. So I was curious if the staff concluded something was good because you could bypass these air dryers.

MR. PELTON: Dr. Minh can speak to that.

DR. MINH: First of all for the air quality questions, I understand Frank Shiff, Dave Pelton, mentioned about the approaches of the air quality control. Let me add just one comment. One of the basis elements we accepted applicant's approach with just one problem. Not measuring the air quality at various locations but at point was that one of the references like associates EPRI NP 70-79 also recommends the air quality check downstream of the dryer so that there is a reasonable assurance that the air supply into the pressurized system is adequately checked, and that would be the reasonable air quality fed into the pressurized system. And that was another one.

And the other one is that my understanding was that the dryer LP reflects the condition of the

dryer so if the LP is too high then the dryer is not working well, and bypassing the dryer will lead to the initiation of the corrective actions and so on; that was my understanding. However the applicant can add some more comments on their actions there for further clarification.

MR. DAILY: Perhaps one of the issues in bypassing the air dryer is if the station routinely bypasses it without placing another air dryer in service. I was at a plant once before, and they had many air problems, but as far as actual experience and performance at the station at Kewaunee, how often does an air dryer get bypassed with no other air dryer being placed in service in that case?

MR. HOLIAN: This is Brian Holian. We can take that question. I think the SER statement that I take out of this, other than the previous discussion, the SER statement, the because statement, is an item we look at, and we need to look at. And we don't want to overstate or understate the conclusion.

MEMBER STETKAR: If it's the only automatic action you certainly don't want to block the airflow, but you certainly don't want to say, because you can bypass it it's okay.

MR. HOLIAN: We don't want the conclusion

to make it sound like that, and we'll work that issue.

MEMBER STETKAR: The bypass line, I don't know where you take the air sample, but I did look at the PNID, and the bypass line not only bypasses the dryers, it also bypasses the downstream filters from the dryers, so whatever is in the supply from the air compressor goes into the header and migrates wherever it wants to go from that point forward.

MR. DAILY: We will need to explore that with the station and find out what actually happens and revisit that. I think that is an excellent point.

MS. TILTON: The related exceptions within the compressor monitoring program, the applicant agreed to amend the application to include these two exceptions with appropriate justification.

Related to the external surface monitoring the inspectors found two deficient areas. Instructions lacked specific requirements to focus on identifying aging effects, and walkdown checklists did not include an attribute of corrosion on uncoated surfaces.

In response the applicant agree to revise these instructions and procedures to adequately address these deficiencies.

Related to the metal fatigue of reactor coolant pressure boundary, the inspectors found that

fatigue monitoring of the reactor coolant hot leg heat exchanger was not included in the program. Our report concluded that defined cycles for the heat exchange would be exceeded prior to the end of extended operation. The applicant initiated follow up action to ensure adequate fatigue monitoring for the reactor coolant hot leg sample heat exchanger.

Our team review resolved, related to the incorporation of operating experience into each program. The inspectors were unclear whether the applicant considered external operating experience for the aging management program. Specifically the operating experience section within the aging management program binders only had examples of internal operating experience.

The inspectors questioned the applicant and reviewed additional documentation. As a result the inspectors concluded that external operating experience is being identified, reviewed, evaluated and tracked, and factored into the aging management program to ensure program effectiveness.

Overall scoping of nonsafety systems, structures and components and application of the aging management program to those SSCs was acceptable. Document supporting the application was auditable and

retrievable. And based on the review of the selected sample our inspection results support the conclusion there is reasonable assurance that the effect of aging will be adequately managed.

CHAIRMAN BONACA: Regarding the corrective action reports for operating experience, I agree that I'm sure that they review operating experience of sister plants and reflect that. The problem still remains that when I look at the programs in Appendix B the only references are always made to the experience of the plant, and it's hard to believe there isn't some inclusion about the experience that could be brought to bear there.

MS. TILTON: During our review initially we found that the only examples we had of operating experience being factored into the aging management program were internal examples. Again, as I mentioned, after further review, they do incorporate external operating experience within their corrective action program. Therefore examples that were brought up through their corrective action program had reviewed external operating experience.

CHAIRMAN BONACA: I understand. I guess I'm not communicating correctly. It seemed to me that there has to be some advance out there in the industry

that other people have experienced, and Kewaunee has not. And yet in the case I would see a reference to the experience of the industry that was not the experience of Kewaunee.

MR. DAILY: What you seem to be asking is whether or not there is documentation of plant XYZ has this issue, we reviewed it and we did these 123 actions as a result.

CHAIRMAN BONACA: Yes, that's exactly right. I would expect in one case or three cases you would have some examples. There are none. And that's what is striking to me.

MR. DAILY: Maybe we could as former staff members might be able to --

MR. ROGERS: Bill Rogers, Division of License Renewal. Actually we discussed that during the scoping methodology audit. What we initially did is we had the applicant management staff give a presentation, an overview presentation on how they considered operating experience in general. And during that presentation they went through the process of looking at the internal operating experience, how they went through the database, and also how they considered the external operating experience. And relative to your question, one thing we did ask them

is how did you determine what OE to put inside your binders, your AMP binders. And the answer was, they had determined to include representative examples in the binders. And representative examples were ones that they thought were probably most illustrative of the AMPs in particular.

So it's really a small sample and a small representation of the overall look that they did. So we reviewed that during our audit, and in addition the regional office did that during their inspection. So although it's not really represented in the binders, it was pretty clear that the applicant had considered that during the overall process.

CHAIRMAN BONACA: And I appreciate it. I'm not going to open it up, because I trust the fact that you performed an inspection, so that confirms the experience. Thank you.

MR. DAILY: We may actually have heard one example even this morning during Dominion's presentation on the reactor vessel had replacement because of industry concerns with the CDRM cracking.

However, I guess maybe your comment is that it's unfortunate that that didn't show up in the LRA application itself.

CHAIRMAN BONACA: I was thinking just

about the example. That's a big one. They had no problems there, and that's wonderful, but they took actions to replace the head.

MR. DAILY: They wanted to do that instead of maybe some other plants which should remain anonymous in other parts of the country, what they do.

CHAIRMAN BONACA: Okay.

MR. DAILY: Thanks Caroline for that presentation. If there are any other questions on the regional inspection?

CONSULTANT BARTON: Yes, I have a question. On the inspection report it seems that the team performing walkdown inspections, for quite a bit of systems, and you had the opportunity to get inside containment. What is your assessment of the overall material condition of the site?

MS. TILTON: Per our assessment the overall material condition was good inside containment. The rest of the inspectors performed mode three post-shutdown walkdowns last year during the refueling outage, and they came to the same conclusion. They found no items of concern.

CONSULTANT BARTON: Thank you.

MR. DAILY: Thanks, Caroline.

Now let's move on to SER Section 3, aging

management programs. And aging management reviews, and we had several topics that we will be bringing up.

The applicant submitted and the staff reviewed 34 aging management programs. And over 4,800 aging management review line items. Of these 34 AMPs 13 programs were presented as consistent with the GALL report. One was considered a plant specific program; seven as consistent with exceptions; eight with enhancements; and then five programs were presented as consistent with both exception and enhancements. So that is just a breakdown of where the aging management programs actually fell in the matrix.

As a result of the staff's review of the aging management programs and aging management reviews, four open items were identified which again are summarized here, and we will now discuss those in the following slides. And of course some of this may seem as a repeat from Dominion's this morning. It's not intended to be a complete repeat, but perhaps we will give some of the staff's perspective in some of these slides.

The first open item relates to the issue of Fatigue Pro and the applicant's metal fatigue calculations. The staff noted that the applicant's aging management program relies upon this software in

order to perform certain fatigue calculations as indicated in the application Section B 3.2. As the ACRS is aware, staff has issued a regulatory issue summary, No. 2008-30, which discusses this issue concerning Fatigue Pro and it's stress-based fatigue module in that it does not use all six components of a transient stress tensor in order to perform the analysis. Whereas the ASME code, Section 3, subarticle NB-3200, does recommend and call for use of all six of those components.

The RIS recommends that license renewal applicants who use this simplified calculation methodology need to perform some confirmatory analyses in order to demonstrate that their simplified approach provides acceptable results. This open item affected two RCS components: pressurizer surge line hot leg nozzle, and the charging leg nozzle. Dominion has agreed to perform confirmatory analyses on these two components. They submitted the results, and a summary report, to the staff on June 1st, which showed their effort to resolve this item, and the staff of course now is in the process of reviewing this response, and we will be confirming its acceptability for the final SER.

The second item identified concerns

related to primary water stress cracking and corrosion in the applicant's LA600 steam generator divider plates. The staff noted that recent foreign operating experience in recirculating steam generators with a similar design to Kewaunee's has identified noticeable cracking due to primary water stress cracking corrosion in the upper portion of the steam generator divider plates, even with proper primary water chemistry. Specifically cracks have been detected in the sub runner divider plate area, and some of them even going to depths of approximately one-fourth to one-third of the way through the wall in the divider plate thickness. Therefore the staff is concerned that the primary water chemistry program alone might not be totally effective in managing these aging effects of cracking due to PWSCC, and we issued an RAI to the applicant on March 26th of this year requesting that the applicant discuss the materials of their steam generator divider plate assemblies. If these materials are susceptible to cracking, for example, if it's alloy 600 materials instead of alloy 690, then to discuss the potential that cracking of the divider plate might propagate into other components, for example, up into the tube sheet platter, or into the RCS steam generator head, the channel head or the

triple point.

Finally the staff requested that a propagation into these components cannot be positively ruled out, the applicant should describe an inspection program ensuring that there are no cracks propagating into other items that could challenge the integrity of the RCS pressure boundary and so forth.

And on July 22nd, as Dominion mentioned, they provided the RAI response. Staff is no in the process of going through that process, and will confirm its acceptability during the final SER.

MEMBER ARMIJO: Can you provide a little more detail on that cracking? Is it in the - does it initiate in welds in the divider plate, or is it on the bulk material? A little more information.

MR. DAILY: We have some extra slides we can throw up onto the screen here, and perhaps Dr. Hiser might be able to --

MR. HISER: These are not in the weld material itself. Maybe in the heat affected zone but it's in the base material.

MEMBER ARMIJO: Of the divider plate stub runner.

MEMBER SHACK: But it is in the high residual stress area, then?

MR. HISER: Presumably, yes. Presumably.

MR. DAILY: Yes, these examples apparently were detected first in several inspections that were done in France as well as up in Sweden with the Ringhals plant. And we actually have some slides that are - we have a transferee that is over working with us from the French Nuclear Regulatory Agency who was involved in some of this, and they were willing to provide a couple of examples of cracks. This particular crack here was in the stub liner area of the divider plate, and it shows intragranular nature, which this is a micrograph etching that was lifted and placed under the microscope so that they could photograph it. And it shows how it propagates along the grain boundaries.

CONSULTANT BARTON: These are not Kewaunee, though?

MR. DAILY: No, these are foreign slides.

(Laughter)

MR. HISER: One of the concerns we on this is that French plants have looked, numerous plants have identified cracks, and U.S. plants have not looked. So we don't know what condition it is.

MR. DAILY: We have no data.

MEMBER ARMIJO: And the materials are

common, the water chemistry are common. Are the designs similar enough the stresses would be --

MR. HISER: There may be some differences in some of the geometry, some of the gross geometry thicknesses and things like that. It's not clear how that would affect the propensity for cracking or propagation of the cracking. And again we know that there is in similar materials, components, structures, cracking; we don't know what the condition is.

MEMBER ARMIJO: What was the duration of time before the French detected these cracks?

MR. HISER: I believe 20 years, somewhere within the first 20 years was when some of the younger steam generators where they were detected --

MR. DAILY: Most of this data that we have here that was shared with us is from the mid-2000s. 2004 to 2009 timeframe. Those steam generators are Westinghouse-licensee constructed model steam generators. They were included in the subject EPRI that had also looked at similar issues. So --

MR. HISER: Some of the other background, multiple inspections of the same steam generator, if you go in and do an inspection and you find some degradation, you don't know, is it prior, is it ongoing, so you come back and look again. In this

case they found a certain population of flaws, came back the second time and found additional flaws. Now it looked like the first flaws that they identified maybe were not continuing to progress. But the continued initiation of flaws and possible coalescence of these is the kind of phenomena that we are concerned about.

MEMBER ARMIJO: But not through the divider plate itself?

MR. HISER: They do not appear to go through wall extensively.

MEMBER SHACK: What, they initiate on the hot leg side and then --

MR. DAILY: Most of them apparently have been found on the hot leg side. I do believe that a couple have been found on the cold leg side. And the maximum depth is approximately 8 out of 34 millimeters according to the data that we got.

MR. HISER: The one concern that we have is that the industry has done some evaluations, and the staff generally agrees that the cracking in the divider plate itself is not a safety concern, so we have not issued a generic letter or any other generic guidance because we in the Part 50 realm at least it's not a safety concern. But we now issue a license for

a plant to go to 60 years, there is the potential that they have a degraded component. We don't want to find new phenomena, year 59, that these cracks can grow into the kiting or out into the base material and cause a reactor coolant leakage. That's the kind of thing that we want to avoid.

MEMBER ARMIJO: Yes, Alan, that picture you are showing there, is that sort of a dye penetrant picture of a crack? What are you looking at there?

MR. DAILY: I believe this is a composite of several photographs of a long section in the stub runner, and this is a PT enhanced photograph that was taken during - on one of the affected generators in 2005.

MEMBER ARMIJO: This is just part of a generic issue that the staff is looking into in Kewaunee?

MR. HISER: That is correct. Kewaunee is the first plant that has alloy 600 divider plate materials, and that's why we are pursuing it with them.

MR. DAILY: I think part of the concern, too, is with steam generator histories, and we had some offline discussions of over the last 30 years or so that we have been associated with, many times we

have what we think is a great analysis only to find out in a couple of years that something new crops up, and nature doesn't really read our engineering reports. So we are just not sure that not being a little proactive is the right way to go.

CHAIRMAN BONACA: On metal fatigue, the reactor coolant pressure boundary, and applicant's use of Fatigue Pro, it's not the first time that this issue has come up, is it true?

MR. HISER: No, that's correct. Numerous plants have used Fatigue Pro. It is standard practice within license renewal for the applicant or licensee to update their calculations using --

CHAIRMAN BONACA: But I am saying that the fact that they did not incorporate portions of the stress tensor, that is not the first time it's happened.

MR. DAILY: That is not the first time. This is actually just the way that particular module in Fatigue Pro is designed. And that was why the staff identified this a couple of years ago, and it resulted in the issuance of a regulatory issue summary to get word out to the industry, and of course this may have been a case where documents crossed in the mail so to speak, because 2008 was the same time that

Dominion was submitted.

CHAIRMAN BONACA: I was going to ask if it was worthwhile to have a generic communication.

MR. HISER: And Fatigue Pro is used by numerous plants for cycle counting, and we have no concerns with that. It's just the stress-based fatigue calculation portion.

MR. HOLIAN: This is Brian Holian. I just wanted to add one other thing on that steam generator divider plate. Kewaunee is just in the queue now for the issue, and the ACRS also often asks what about other plants that you have already renewed, and we do pick them up. We are in contact with the regions. We have a chance in our next inspection that Caroline and her folks go out to, and all the regions do, on 7013, to check on how they take this operating experience and put it into their aging management program that they already have for steam generators.

So we have that closure loop also to inspect plants on how well they do if they have already received the license.

I'm going to go into buried piping here in a minute, and Kewaunee is also in the loop now for the staff pushing a little harder on buried piping commitments. So nothing unusual with their program

with that being an open item other than their coming through at a time when the staff and operating experience both are pushing for more inspection.

CHAIRMAN BONACA: Good.

MR. DAILY: Next slide.

The third open item involves as we had mentioned the applicant's aging management programs for buried and underground piping and tanks. Staff has noted a number of recent industry events involving leakage from such buried and underground piping and/or tanks, and is concerned about continued susceptibility, the failure of these particular components, again whether they were buried or underground but within the scope of license renewal. So the staff issued an RAI on May 27th, 2010, requesting that the applicant discuss the instances of leakage or adverse conditions that they have identified there at the Kewaunee Power Station and how the applicant's aging management programs have been revised in order to address any of these conditions. And we have specifically within the past five years.

And then secondly to discuss how the aging management programs will address these recent industry operating experience concerning aging effects in buried, underground and limited-access piping and

tanks. The applicant has provided their response again July 22nd, and the staff is in the process and in a dialogue to confirm the acceptability and will make this final determination on this for the final SER.

The fourth open item identified some issues in the applicant's work control process program. Again, as Dominion had discussed in their presentation, on September 25th, 2009, Dominion amended its work control process program, and changed it from a plant-specific program to a new program which when enhanced would be consistent with two of the GALL reports, aging management program: The one-time inspection program and the inspection of internal surfaces and miscellaneous piping under those situations.

And the RAI that was issued requested the applicant to provide some explanations or justifications on some of the issues regarding not completely specifying minimum percentages or sample sizes or inspection frequencies of populations. In other words if they are all lumped together is that really the right way, or should we get different component groupings and so forth?

We also requested clarification on the operating experience examples that they had provided

to us. Those operating experience examples actually created some uncertainties in the staff mind as to whether or not they were effectively managing it.

MEMBER STETKAR: Could you elaborate a bit on that? Because I asked the applicant a little bit about how they've accounted for their operating experience in the current work control process. In terms of informing the frequency of inspections or the locations of inspections or how you might organize your sampling. And I didn't get much feedback on that. So I'm going to ask you in terms of, you said it - you used the term, it's created uncertainties. How are you following up on this other than it's obviously an RAI and --

MR. DAILY: There are some issues like that in regard to the frequency. One of the problems in reviewing an application, of course, is you have to review what is submitted. And one of the particular examples that was cited concerned a pipe whose flow became 92 percent blocked, and it was discovered during some maintenance, and of course they corrected the corrosion blockage, and we just kind of stepped back for a second and said, but if it's 92 percent blocked how does that show a proactive program? So is this really what you wanted to say or what? We were

just confused, so the applicant has agreed instead to address this under some different circumstances in order to provide the right kinds of examples.

MR. PELTON: Dave Pelton, branch chief responsible for the work control process or the aging management programs associated with it. Initially the program proposed by the applicant is a program I think you heard earlier that they applied at other Dominion sites. And the first issue the staff had initially was the scope of the component types that were included under the program for Kewaunee was, frankly, significantly larger than had been applied in the past.

MR. DAILY: It is 25 percent of all their line items.

MR. PELTON: In order to have assurance that their program which you heard earlier is one that is largely based on an opportunistic approach -- does anyone want to explore that beep or are we good?

MEMBER STETKAR: No, that is just the phone line.

MR. PELTON: We just wanted to have some reasonable assurance that the work control process as initially defined would cover a sufficient breadth and depth of equipment types such that over the period of

extended operation if you drew a big chart you would say, hey, it seems to be a consistent distribution across component types rather than a siloed or lumped area. And we had discussions with Dominion folks and I think we were all in agreement that that is certainly something that needs to be appropriately managed.

Moving forward through the request for additional information process, getting more and more specific into what sampling approaches, how do we have that kind of assurance, it was Dominion who made the determination to have a shift in direction from the originally proposed program to then look at a couple of existing aging management programs in the GALL. It was not at the request, direction or otherwise of the staff.

MEMBER STETKAR: My apologies. (Laughter)

MR. PELTON: But I just want to make it clear, and we made that point clear during the public meeting, that the program is defined in the GALL report are absolutely suitable, acceptable programs, as was the program they had originally proposed. And during - just so you know, to address your earlier comment, during the public meeting we had we did address the issue of, hey, you originally proposed one

program; you are sliding into a different one. The intent here was never to reduce its effectiveness or otherwise prohibit the licensee from doing what was reasonable. So moving forward, we are continuing to explore their methodology for ensuring an appropriate depth and breadth of equipment or component types. So that's basically, without getting into specifics of operating experience, which by the way was considered, that's kind of where we're at right now, and we are working towards an amicable program that would give us reasonable assurance that over 20 years it will be appropriate.

MEMBER STETKAR: Caroline, I don't remember all the details in the inspection report, for this particular program did you do - it's difficult to do kind of a keyword search for this type of issue. Did you specifically kind of drill down into operating experience for this one?

MS. TILTON: Actually we did not collect the work control process as part of our review, because that was the transition in which Dominion was going --

MEMBER STETKAR: Yes, I understand it was kind of a fluid situation.

MS. TILTON: Correct, it was going to

change so we didn't collect it.

MEMBER STETKAR: And also, it's a little bit difficult to do keyword searches, because this is a broader scope program.

MR. DAILY: One of the things we are trying to do, though, to inform the discussions obviously is going back and looking at some of the history, for example, Millstone, North Anna, Surry, which are part of the Dominion fleet. They used the program there. Obviously there must have been some good things there. Are they also present here? Just to make sure like Dave was talking about that we have some reasonable assurance that just because you have 100 problems with one section of surface water piping due to microbiological corrosion that doesn't mean you did 100 inspections.

MR. PELTON: We are trying to make sure that we don't get into that trap, and we will make sure that whatever response is ultimately agreed to, it's well founded and well based within the available operating experience for sure.

MR. MEDOFF: This is Jim Medoff of the staff. I was originally assigned to this review. But to elaborate on like an example of operating experiences originally provided in the original LRA

where we concluded that it may not demonstrate adequate aging. We had an original OE example of where the applicant stated that they had gone back and I think it was like a turbine generator stator cooling heat exchanger, they had done some eddy current examinations of the tubes and they found some pitting through the tubes, and that this demonstrated adequate aging management. But if you looked at the program elements through their original work control process it proposed visual examinations. So one of the things I perceived was that they detected the aging using an eddy current examination, but eddy currents weren't within the scope of this program and still aren't part of the program. So that would be an example where we looked at the OE, and I was wondering why would you do eddy currents for heat exchanger tubes rather than visual examinations, because that was the technique that detected the aging effect. So there are a number of OE examples that they had given where we had other - whether their handling of the OE or their determinations would demonstrate adequate aging management.

MEMBER STETKAR: It sounds like this is still a bit in the evolving stage.

MR. DAILY: Correct. We are working on

it, yes.

MEMBER STETKAR: We're working on it? Okay, good.

MR. DAILY: Was there another question? Next slide.

As a part of LRA Section 3.5, the applicant supplied data regarding the aging management of in scope but inaccessible concrete that was below grade. We also discussed this in the safety evaluation report. And what we are showing here is - are the data that was supplied to us during the license renewal application, specifically looking at whether or not soil is aggressive in the area of the related concrete structures, with the pH readings. And of note are the chloride readings which the limit is 500 and there were readings in the 2007-2009 timeframe of 1,240 ppm at some of the wells, and in addition the sulfates were as noted.

So to make a long story short in this area because again Dominion did discuss it, the applicant has committed to taking additional coring samples both prior to - core samples in the concrete wall and foundation areas in the vicinity of the high chlorides in order to make sure that there is no possible degradation. If those chloride levels do not decrease

to below the 500 ppm within the first 10 years of a period of extended operations, then the applicant is committed also to perform those core samples again in order to examine and look for any aggressive attacks due to chlorides in the concrete or the rebar.

Staff also wanted to note that the applicant's structures monitoring program also contains a provision to sample groundwater chemistry at least once every five years, and of course if their groundwater program they're sampling as indicated.

Next slide. Regarding SER Section 4 which is the time limited aging analysis, particular note in Section 4.23 the pressurized thermal shock section, we have this highlight here to discuss the PTS limits for reactor vessel material due to neutron embrittlement. The limiting components with respect to the projected PTS values at the end of 60 calendar years were 52.1 EFPY are as indicated here on the slide. These are the top three components or locations with regard to how close they are to their limiting values, and the closest one of course is the top value which is the intermediate shell to lower shell girth weld. The limit of course is less than or equal to 300 degrees Fahrenheit, and the calculated value is 297.5. This calculated value was determined using a methodology

that was approved by the staff safety evaluation data back in May of 2001, and it was presented as an exemption to 10 CFR 50.61 as well as a couple of others we didn't note on the slide.

MEMBER ARMIJO: What would that value be if the new PTS methodology was used? I'm just assuming this is not using the new methodology?

MR. DAILY: I believe we actually have our staff member who has conducted the review and analysis.

MR. CHANG: My name is Simon Chang. I'm with the DCI. If they use the newly approved PTS rule, I think basically they are in a much better position. Because a study was performed probably several years ago and published in NUREG 1874. And in that study, the new rule has like a six screen criteria as opposed to the old one. The old rule, the current rule we have only two screening criteria. One is 300 degrees. One is 270. And by the new screen criteria which is relevant to the sequential world of Kewaunee, actually is the 312, the new screening criteria. And based on that results technical results, issued in the NUREG 1874 for Kewaunee, and their - they use - they do not calculate their RTPTS. They calculate the RTPTS in the subunit in a

different way, and they call it RT maxima CW, something like that. But based on that calculation, the Kewaunee numbers are something like 258, so far below 312. So and along with the methodology our evaluation of the methodology approved in year 2001, we are comfortable that the event is close to 300, with 297.5, we are confident that it is okay.

MEMBER ARMIJO: So it has actually got more margin than you would indicate based on this?

MR. CHANG: That's right, based on the newly approved PTS rule.

MEMBER ARMIJO: Okay, thank you.

MR. DAILY: Thank you, Simon.

So the staff's conclusion on this, just to cut to the bottom line on PTS, was that the applicant has satisfactorily demonstrated that for pressurized thermal shock the analyses have been projected to the end of the period of extended operations, appropriately pursuant to the rule 10 CFR 54.21 (c)(1)(ii).

MEMBER SHACK: But this presumably is for their availability, and now power uprate? No new power uprates?

MR. DAILY: I would project that any new power uprates would obviously have to revisit this.

MEMBER SHACK: I mean it didn't include anything in here, any margin to include a power uprate?

MR. DAILY: No, not that I'm aware of in the future, no future I'm seeing from Dominion.

MEMBER STETKAR: It looks like they projected about 87 percent availability, 52.1 over --

MR. DAILY: That is based on the historical amount of availability they actually exposed the FQI, and they added on a 95 percent cycle I believe 27 going forward.

MEMBER STETKAR: But it is an average 87 percent.

MR. DAILY: Over the entire 60 years that would be an average. Next slide.

So in conclusion, and pending successful resolution of all these open items, the staff determines that the requirements of 10 CFR 54.29(a) has been met for the license renewal of Kewaunee Power Station.

This concludes our formal presentation. Of course if there are other questions we could discuss them now.

CHAIRMAN BONACA: Thank you.

MEMBER STETKAR: I have one. It's nothing

that has been discussed by either the applicant or the staff. The subject is small bore socket welds. And I guess my question is a question of consistency in the staff's approach to an acceptable program, because if I read Kewaunee's commitment, there is a commitment number 43. It says five volumetric examinations of ASME Class I small bore socket welds will be performed using a qualified nuclear industry inspection methodology that can detect and size discontinuities within a specific examination volume if a qualified methodology becomes available.

One destructive examination will be performed in lieu of this inspection in the event that a qualified inspection methodology is not available prior to the period of extended operations.

So essentially they've said unless we have an accepted qualified volumetric examination methodology we are going to select one weld out of a population of I think 320 and do a destruction examination of that weld and that's good enough. The staff seems not to have accepted that approach for other very recent contemporary license renewal applications, essentially saying that, well, although there is no qualified methodologies, there are other methodologies in practice, and other applicants have

indeed been -- let me just say other applicants have agreed to use a sampling methodology of some number of welds for volumetric examination.

So this approval seems to be different. We've gone from historical acceptance of visual inspections to an emphasis on a sampling for volumetric examinations to acceptance of a single destructive examination of one weld as being acceptable. So I'm concerned now about consistency, where we are now among the fleet that is coming before us.

MR. HOLIAN: Let me just, this is Brian Holian, and then I'll turn this socket weld to Alan, but the question and the concern is very good. I was going to add one more item to this discussion at the end, low voltage cable, which is not even in your SER, and it's one that you might see another commitment from this utility by the time they get to the final SER. And it's an evolving issue in GALL where we are pushing low voltage cable.

MEMBER STETKAR: This is low voltage cable?

MR. HOLIAN: So this is low voltage cable. So in truth in advertising I wanted to bring that up at the end, and that kind of relates to consistency

issues. But as the GALL grows we get smarter. We find new operating experience we apply, things like that. So I wanted to address that. And I previously mentioned that we don't forget those things. We come back in inspection space to pick them up on previous plants to make sure that they are learning from the operating experience for the license renewal reviews of later plants.

On socket welds I'll let Dr. Hiser address that, but in general this issue is also one that as you know we've evolved to wanting more, and we believe the operating experience and the ability of the plants to do more, you are catching some wording that is a little bit awkward, I'll admit, but let me have Dr. Hiser address this.

MR. HISER: Yes, you are right on target that this is - what we are trying to do is focus things down a little bit, so that we have a common approach with all the plants. What we have been told repeatedly by the industry is there are no qualified techniques. There is no non-destructive technique that can detect and size cracks. What we have seen at the EPRI developed for one applicant was a very good phased-array approach that we are told will be shared with the rest of the industry. Our expectation is

that the question of having a technique that can detect cracks, not necessarily size but at least detect cracks, should be at the window. So commitments such as this, the destructive backstop if you will, should not come into play. I mean our expectation is that there now is a technique that all plants should be able to use. So we will be pursuing this with Kewaunee and others. We may want to have them tweak that commitment somewhat.

MEMBER STETKAR: As I read the commitment Kewaunee basically - their period of extended operation will start in 2-1/2 years, something like that, they are committing to do a destructive examination of one weld. Bill, you are a materials guy, I'm not sure what an examination of one weld out of a large population.

MR. HISER: My expectation is they are not going to be doing the one. They will be doing periodic UT is my --

MEMBER STETKAR: Well, the commitment doesn't say that.

MR. DAILY: That is why this is a SER with open items.

MEMBER STETKAR: There is an open item on this.

MEMBER SHACK: The difference between 42 and 43, 42 calls for period inspections of small bore pipes, and 43 just says volumetric inspection, it doesn't say anything about periodic you know, the prior one says that you will do it during each 10-year ISI, this one as the commitment is, I read it as a one-time five volumetric shot. And so there is actually quite a difference between the small bore commitment and the socket weld commitment.

MR. HISER: I think I misspoke, because for small bore socket welds, this is a one time inspection. There are some plants that have had a history of failures with socket welds, and there it becomes more of a periodic program.

This information is just within the last couple of months, at the EPRI Center.

MEMBER ARMIJO: It is the staff's intent, though, to really get at least a detection capability, a nondestructive detection capability. And if you want to pursue a destructive exam to get an idea of size, that is something else. But just to do destructive exams without any guidance that there might be a crack there, that's kind of a waste of time.

MR. FU: This is Bart Fu. I'm the

reviewer of the license renewal. It is not really the staff's intent to destructively examine. It is only as an alternative. If they haven't had an opportunity. That's why we call it opportunistic destructive examination. If we --

MEMBER ARMIJO: If you were going to cut it out anyway.

MR. FU: If they do a plant modification. Say they have a section of the line, just cut it out, and then you know we will have an opportunity to take a look at the socket welds. And when we talk about one examination, one destructive examination, that could be also a weld in a section of the line.

And also understand this is out of a series of discussions between the staff and the applicant, I believe back from this time last year until January timeframe this year. And the staff learned and knows a lot more now than at that time. And since then I believe Dr. Hiser mentioned EPRI has qualified the program for socket welds.

MR. HISER: I would be careful. One of the words I hate is qualified. And actually the wording I liked is demonstrated capable of detecting degradation at interest. Because from a license renewal perspective, we want to know is the aging

going on. We want to be able to detect it from a license renewal perspective. I don't care if you can size it. Because if you find it, then you are going to have to figure out what to do with it. And that is where sizing comes into play.

MEMBER ARMIJO: I totally agree with that.

MR. HISER: So what EPRI has demonstrated is the capability of detecting cracks. And that is exactly what the staff has been looking at . I think we have gotten bollixed up with the industry on the word, qualified. So we - the staff has tried to pull away from qualified, and just go to demonstrate capable of detecting.

MEMBER STETKAR: That is the type of commitments that I have seen in other - those sorts of words - in other license renewal applications.

MR. HISER: I think Bart is correct that we have resolved this with this commitment many months ago. And I from my perspective I didn't realize that we still had this type of commitment for Kewaunee. We need to go back and relook at that.

MEMBER STETKAR: I think a little bit of our concern is we, as you well know, we have a constant stream of these things coming through us, and our relative attention on how to think about this

issue needs a bit of recalibrating every now and then.

MR. HOLIAN: This is Brian Holian. Your question is very good on these commitments, and we are doing that, even on the period piping. On the 14 plants that we have in house you are going to see some variations in the commitments, but they are well above the one buried piping that we had several years ago 10 years prior, which they should be. But you are getting some variances until we get that new GALL out in December.

MEMBER SHACK: Notice nobody said guided waves for buried piping in this application. And we thank you for that.

MR. HOLIAN: That is right. So we are still working that, and we will take this comment.

MR. DAILY: These are definitely moving issues and evolving, and I think it's a point well taken that the staff is trying to converge everything so that there is some consistency and predictability and usefulness.

MEMBER STETKAR: It is also, there is a message for your people coming in.

MR. FU: I would like to respond to the consistency issue. Kewaunee, we reviewed the plant operating experience. In their experience, you may

recall the few reviews we did with Wayne Arnold and Cooper when they had experienced tracking, especially at Wayne Arnold, they had pretty bad SSC, we're talking about bad chemistry.

MEMBER SHACK: These guys have never had a socket weld fail?

MR. FU: Not class one small bore socket weld; that's in the application, they make that statement.

MR. AITKEN: This is Paul Aitken. We don't have any reported failures of Class I sockets. And we don't have the OE. And Dr. Hiser mentioned the technology. I think there has been some success at EPRI. I know there is a project to be evaluated for further funding that is going to be discussed in the next couple of weeks, but I think that was for a specific configuration, and they would have to expand that scope to include bigger and more techniques and things like that. So they are some advancements. We are very much in touch with that. And it is our intent to meet the spirit of this commitment to do the necessary volumetric exam.

MR. DAILY: And clearly the lead tests or the visual tests already shows a failure that is not detecting ahead of time and that is not what we're

about.

CHAIRMAN BONACA: Any other questions? For the presenters?

If not, I want to thank you very much for your great presentation and the licensee too, and I would like to go around the table and get some feedback from the members regarding two issues. One is, do we need a interim letter, and two, what your views about the significant issues here. And I'll start with you, Charley.

MEMBER BROWN: I don't have any additional issues. I would not - based on what I've heard I wouldn't go down the interim letter path. But somebody else might have a different perspective.

CHAIRMAN BONACA: Okay, Bill.

MEMBER SHACK: Yes, I don't see any - to me the most confusing issue is the work process control one, and everybody seems to be working that one. I'm not sure we'd add anything to it by adding a letter, but we will be looking at that when it comes time for the final SER.

CHAIRMAN BONACA: In my mind I was thinking of the three air dryers. Is there something that we have to communicate? I think we did already, but anyway that is the example. John.

MEMBER STETKAR: I don't have anything to add. I agree with Bill. I think that --

CHAIRMAN BONACA: No interim letter?

MEMBER STETKAR: No interim letter necessary.

MEMBER ARMIJO: I agree. I don't think there is need for an interim letter. I think the presentations were very helpful, I think from both the staff and the applicant. I think the open items are things that will get closed - there is a clear path to get those things closed. I think they are on the right track. I don't see a problem.

CHAIRMAN BONACA: John.

CONSULTANT BARTON: Resolve the open items, that's all I see in this plan.

CHAIRMAN BONACA: The licensee should note that.

Okay, so that is the feedback and I will report to the board, to the committee, in two weeks in the full meeting, it will be a brief update anyway.

And with that then the meeting is adjourned.

(Whereupon at 11:52 a.m. the proceeding in the above-entitled matter was adjourned)

Kewaunee Power Station

Presentation to Advisory Committee on Reactor Safeguards - License Renewal Subcommittee

August 18, 2010

Participants

- Steve Scace – Site Vice-President
- Alan Price – Engineering Vice-President
- Michael Wilson – Station Safety & Licensing Director
- Stew Yuen – Engineering Director
- Paul Aitken – License Renewal Project Manager
- LR Project Team Members
- Station Staff

Presentation Outline

- Background
- Operating Information
- License Renewal Application
- Aging Management Programs
- Commitments / Implementation
- Technical Items of interest
- SER Open Items

Background

Site Description

- Located in Kewaunee County, Wisconsin
- Once-through cooling from Lake Michigan
- 2-Loop Pressurized Water Reactor
- Westinghouse Electric Corporation (NSSS), Pioneer Service and Engineering Co. (A/E)
- Turbine / Generator – Westinghouse
- 1772 MWt
- Steel Containment Vessel with Concrete Shield Building

Background


N
Menominee
Marinette
Oconto
50-Mile Radius
Shawano
Green Bay
Door
Green Bay
Kewaunee
Kewaunee
Lake Michigan
Outagamie
Appleton--Neenah
Brown
Kewaunee Power Station
Point Beach Nuclear Plant
POINT BEACH STATE FOREST
Two Rivers
Winnebago
Manitowoc
Manitowoc
Calumet
Oshkosh
Lake Winnebago
Fond du Lac
Sheboygan
Sheboygan

Background

Plant History - Licensing

• Construction permit	August 6,1968
• Operating license	December 21, 1973
• Commercial operation	June 16, 1974
• Uprated Power License	
◇ MUR (1.4%, 23 MWt)	July 2003
◇ Stretch uprate (6%, 99 MWt)	February 2004
• Plant Owner change to Dominion	July 2005
• Operating License expires	December 21, 2013

Operating Information

Current Plant Status

- ◇ Operating Cycle 31
- ◇ 100% Power
- ◇ 301 Days On-line
- ◇ 1268 Days since Last Automatic Trip
- ◇ Next refueling outage: February 2011

Operating Information

Major Improvements

• Replaced Main Condenser Tubes	1985
• Replaced Feedwater Heater Tubes	1992
• Replaced the Plant Process Computer (twice)	1993 / 2005
• Steam Generator Replacement	2001 {pic}
• Replaced Component Cooling Pumps	2001
• Replaced Upper Internals Split Pins	2004
• Replaced Reactor Vessel Head	2004

Operating Information

Major Improvements

• Replaced Reactor Coolant Pump Internals	2003 / 2008
• Constructed ISFSI	2009
• Replaced Service Water Pumps	2009
• Improved Tech Specs Draft SER Issued	2010
• Switchyard Improvements	On-going {pic}
• Transformer Replacements	On-going

License Renewal Application

- License Renewal Project Overview
  - ◇ Diverse project team members (Site, Corporate, Contract)
  - ◇ Experience with Surry, North Anna, and Millstone LRAs
  - ◇ Site involvement in IPA and AMP development
  - ◇ Participation in NEI LR industry working groups
  - ◇ Involved with GALL Updates (Rev. 0 & Rev. 1)

License Renewal Application

- LRA Development
  - ◇ Scoping and Screening
    - Consistent with 10CFR Part 54 and NEI 95-10
    - Utilized site component databases, controlled drawings, design and licensing documents
    - In-scope structures, components and commodities were screened to determine if AMR was required
  - ◇ Aging Management Review
    - Consistent with 10CFR Part 54 and NEI 95-10
    - Utilized industry aging reports and plant-specific OE
    - Results showed good consistency with GALL Report (Rev. 1)

License Renewal Application

- LRA Development
  - ◇ Time-Limited Aging Analyses
    - Reactor vessel neutron embrittlement
    - Metal fatigue and thermal cycle limit assumptions
    - Environmental qualification of electrical equipment
    - Metal containment and penetrations fatigue
    - Misc TLAAs
      - Crane load cycle limit
      - Reactor coolant loop leak-before-break
      - Reactor vessel underclad cracking
      - RCP motor flywheel crack growth

Aging Management Programs

- 34 total
  - ◇ 28 - Existing programs (1 plant-specific)
  - ◇ 6 - New programs
- GALL Consistency – Programs showed good consistency with model AMPs in GALL

Commitments / Implementation

- Commitments were documented in the LRA and modified as needed during NRC review
  - ◇ 45 License Renewal Commitments
    - 28 original
    - 19 added
    - 2 deleted

Commitments / Implementation

- LR commitments have been entered into the Licensing Commitment Tracking System
- Implementation of commitments is in progress and will be completed on the schedule provided in the LRA or sooner
- Leveraging fleet knowledge and experience
- Dominion participating in NEI-LR Implementation Working Group
- Benchmarking others in the industry

Technical Items of Interest

- Groundwater Quality
- Historical Reactor Trip Transients

Technical Items of Interest

- Groundwater Quality
  - ◇ Elevated groundwater chloride concentrations were indicated near in-scope structures based on monitoring well sample readings {pic}
  - ◇ Readings were marginally over 500 ppm limit
  - ◇ Elevated readings attributed to de-icing methods – use of road salt
  - ◇ Changed de-icing practice to incorporate sand mix to reduce total chloride deposited on ground

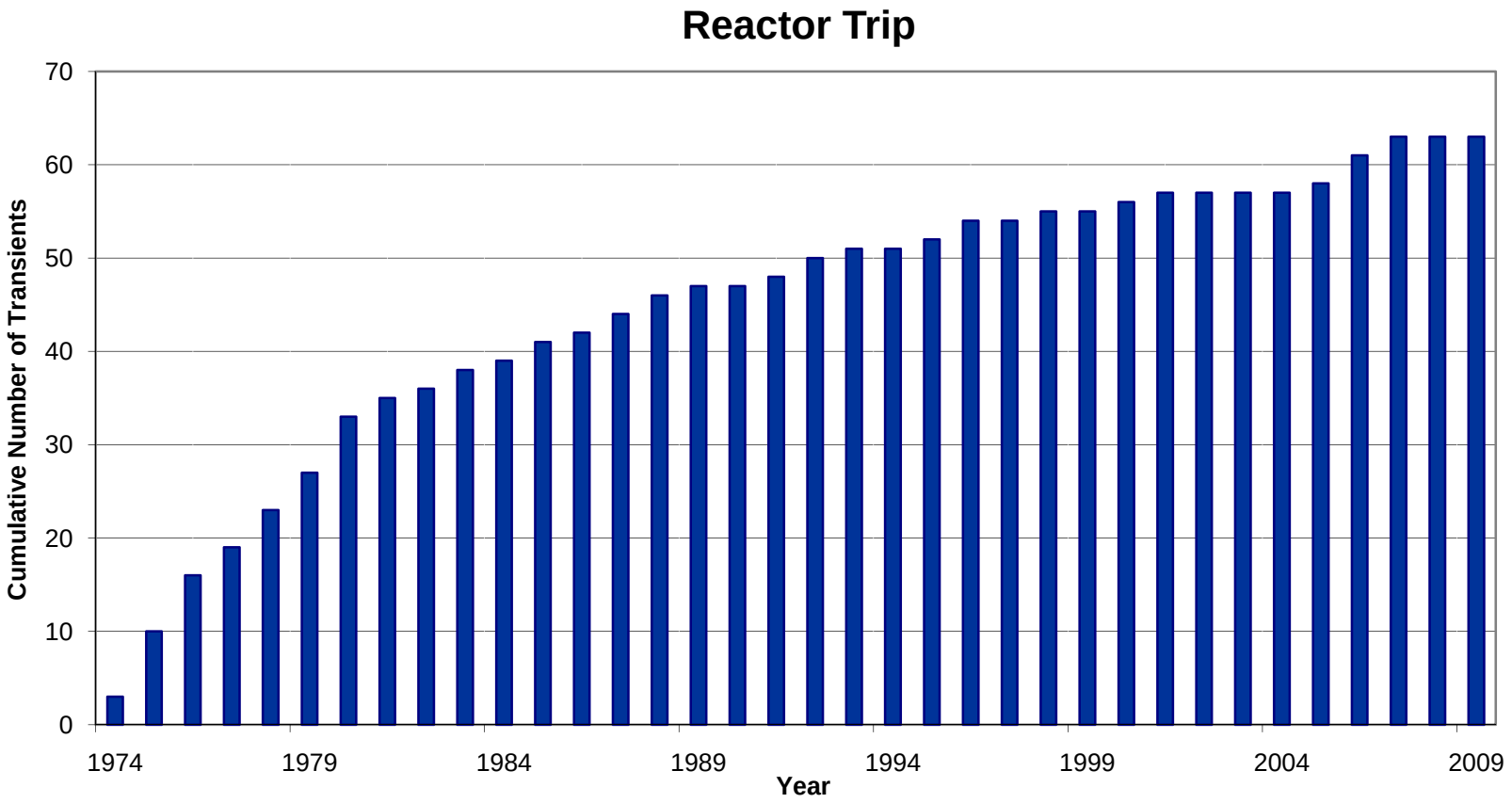
Technical Items of Interest

- Groundwater Quality
  - ◇ No significant effect on structure based on:
    - Below grade concrete protected by waterproofing membrane
    - Minimal potential for exposure of concrete due to low groundwater elevations
    - Low permeability concrete – only minor in-leakage noted during 36 years in service
  - ◇ Core removal and testing planned for confirmation
  - ◇ Additional coring in 10 years if Cl^- readings do not decrease <500 ppm

Technical Items of Interest

- Historical Reactor Trips
  - ◇ Rate of occurrence of reactor trips reduced since initial operations
  - ◇ Reactor trips have been recorded since plant initial startup
  - ◇ Reactor trips are monitored as a transient for fatigue cycle counting purposes

Technical Items of Interest



SER Open Items

4 Open Items (OI)

OI 3.0.3.2.20-1	Use of FatiguePro Software
OI B2.1.32-1	Work Control Process Program
OI 3.1.2.1.7-1	S/G Divider Plate Cracking due to PWSCC
OI 3.0.3.2.4-1	Recent Operating Experience for Buried and Underground Piping and Tanks

SER Open Items

OI 3.0.3.2.20-1: Use of FatiguePro Software

- Initial evaluation of environmental effects on fatigue life utilized EPRI FatiguePro stress-based fatigue (SBF) monitoring for 2 locations
- RIS 2008-30 identified potential for non-conservatisms when FatiguePro SBF applied – RAI B3.2-2 issued
- LR Commitment 41 established to re-evaluate these locations using ASME Code, Section III, NB-3200 compliant methods
- Acceptable 60-year fatigue life results were obtained and a summary report submitted in response to RAI B3.2-2 to support closure of Commitment 41

SER Open Items

OI B2.1.32-1: Work Control Process Program

- Work Control Process program revised following initial submittal in response to NRC concerns
- WCP (as revised) is a new program that is consistent with –
  - ◇ NUREG-1801, M32: One-Time Inspection
  - ◇ NUREG-1801, M38: Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

SER Open Items

OI B2.1.32-1 (cont'd)

- NRC requested additional clarifications for:
  - ◇ Selection of one-time inspection sample sizes and schedule for completion of inspections
  - ◇ Minimum sample size for periodic inspections and inspection frequencies for inspections of internal surfaces
  - ◇ Capability to detect aging effects, based on OE examples submitted
  - ◇ Clarification of the commitment to implement the WCP program

SER Open Items

OI B2.1.32-1 (cont'd)

- Additional information provided to address NRC request:
  - ◇ M32: Clarified the methodology used to determine one-time inspection sample size
  - ◇ M38: Clarified that periodic inspections are based on planned surveillance and maintenance activities, and not predetermined sample size; and that inspections are expected to be performed multiple times due to periodic nature of program.
  - ◇ New Commitment 47 established to provide relevant OE within 2 years after implementation of WCP
  - ◇ Clarified that the WCP AMP is a new AMP and that one-time inspections will be completed prior to period of extended operation
- A response to RAI B2.1.32-1 has been provided to address this Open Item

SER Open Items

OI 3.1.2.1.7-1: S/G Divider Plate Cracking due to PWSCC

- RAI 3.1.2.2.13-1 requested:
  - ◇ identification of materials of construction for SG divider plate assembly
  - ◇ evaluation of the potential for PWSCC cracks to propagate to base materials or cladding, and provide an inspection program if required.
- Request was based on recent foreign operating experience with SG divider plate cracking

SER Open Items

OI 3.1.2.1.7-1 (cont'd)

- EPRI Steam Generator Task Force evaluating concern for generic industry action
- Kewaunee monitors and evaluates industry (foreign and domestic) operating experience, including steam generator OE
- Kewaunee SGs replaced in 2001, limited service life for cracking
- Crack propagation into base materials or cladding limited by:
  - ◇ Kewaunee divider plate assembly welds are Alloy 52/152 (PWSCC resistant)
  - ◇ Industry experience indicates that PWSCC cracking stops when non-susceptible materials are encountered (i.e., SS, LAS, Alloy 52/152)
  - ◇ No domestic or foreign OE related to crack propagation into base materials
- A response to RAI 3.1.2.2.13-1 has been provided to address this Open Item

SER Open Items

OI 3.0.3.2.4-1: Recent OE for Buried and Underground Piping and Tanks

- RAI B2.1.7-3 requested:
  - ◇ Identification of buried and underground components addressed by the Buried Piping and Tanks Inspection and the External Surfaces Monitoring programs;
  - ◇ Identification of updates to these programs to incorporate lessons learned from recent events related to buried piping leakage

SER Open Items

OI 3.0.3.2.4-1 (cont'd)

- Buried piping and tanks, and planned inspections

System	Prior to PEO	During 1st 10 Yrs of PEO
CW piping (15'/200')	Two*	Two*
DG FO piping (500')	One	One
DG FOST (3)	One tank	One tank
FP piping (2350')	Three	Three

*One for stainless steel piping and one for carbon steel piping

SER Open Items

OI 3.0.3.2.4-1 (cont'd)

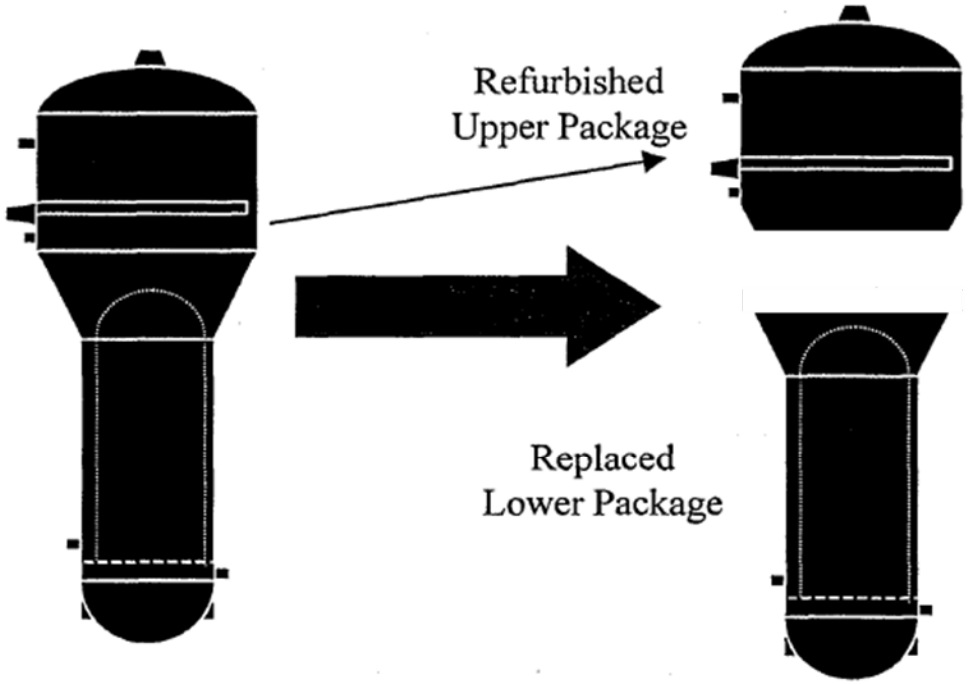
- Industry Operating Experience
  - ◇ NEI NSIAC buried piping initiative adopted by Kewaunee
  - ◇ Kewaunee evaluates industry operating experience for buried piping program enhancements
  - ◇ A site program owner is assigned responsibility for implementation of the buried piping program
  - ◇ Dominion actively participates as a member of EPRI Buried Piping Integrity Group
- A response to RAI B2.1.7-3 has been provided to address this Open Item

Kewaunee License Renewal

Questions

Kewaunee License Renewal

Additional Slides



Original SG
Model 51

Replacement SG
Model 54F

Key Improvements

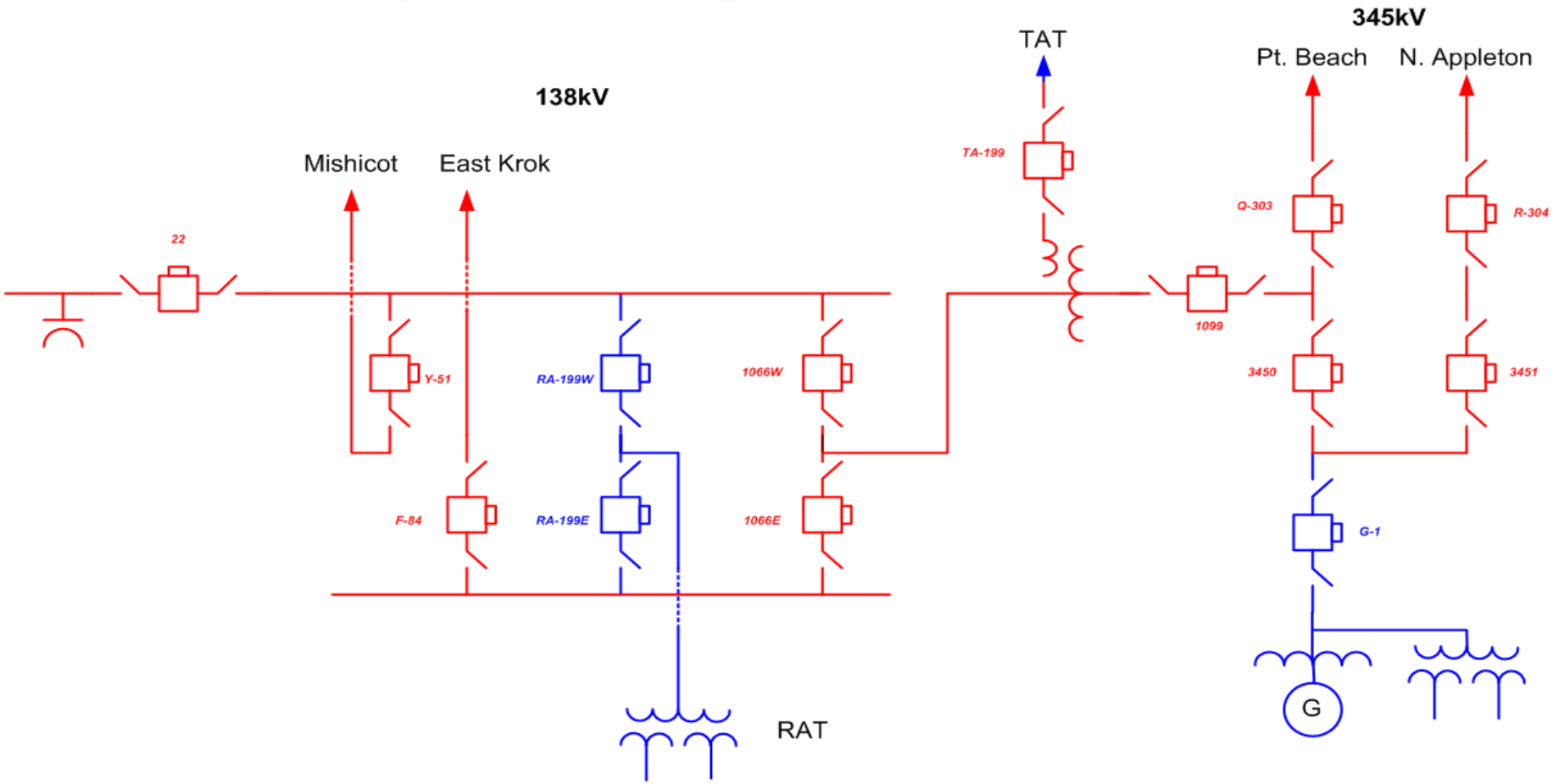
Steam Flow Limiter
Separator Mods
Feedwater Ring

Alloy 690 Tubes
Stainless Support Plates
Alloy 600 Divider Plate with 52/152 weld material

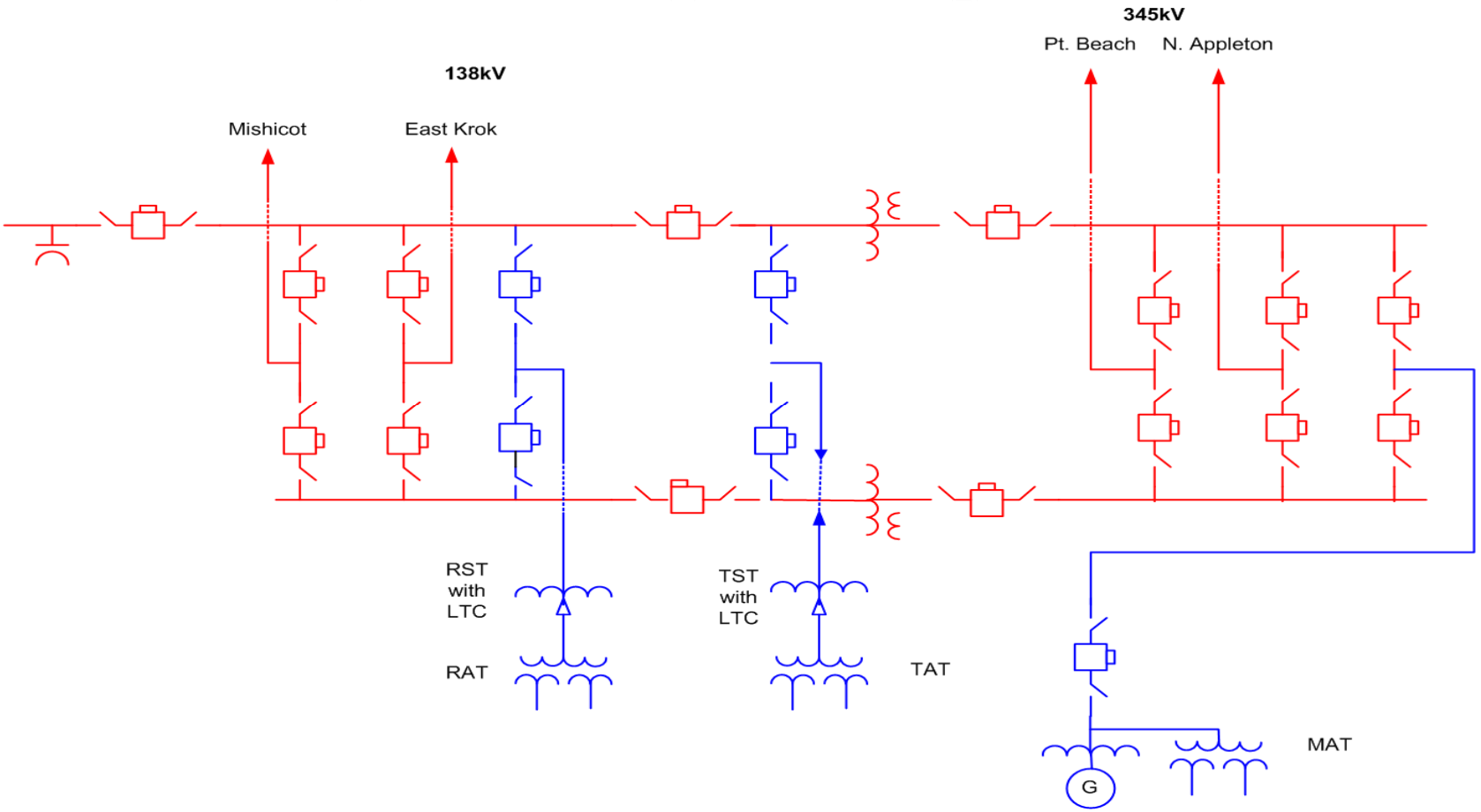
Not Unique to KPS
Similar Replacements Performed for Surry ('80 & '81) and North Anna ('93 & '95) + others.

Back

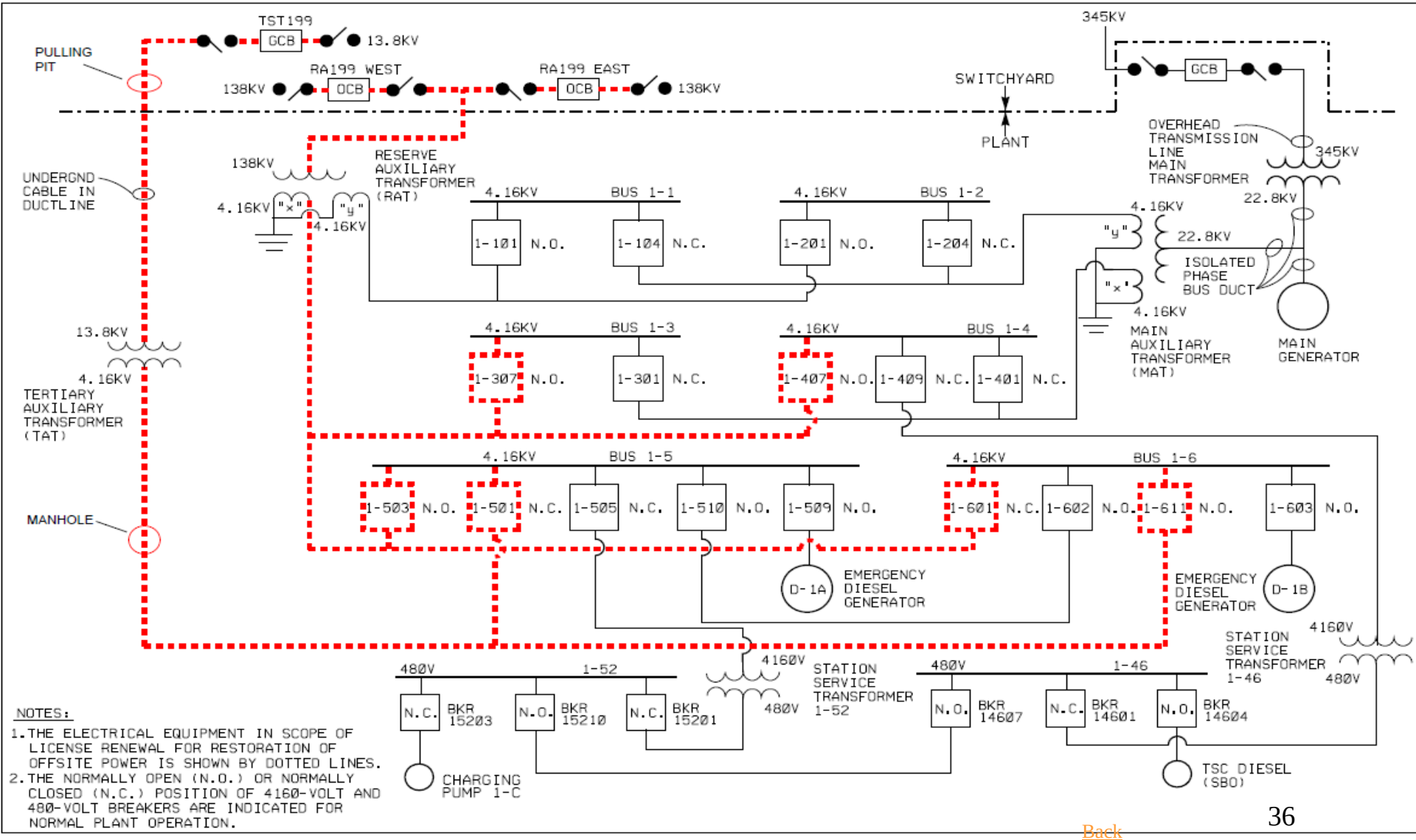
Switchyard Layout in 2006



Switchyard Layout by 2011

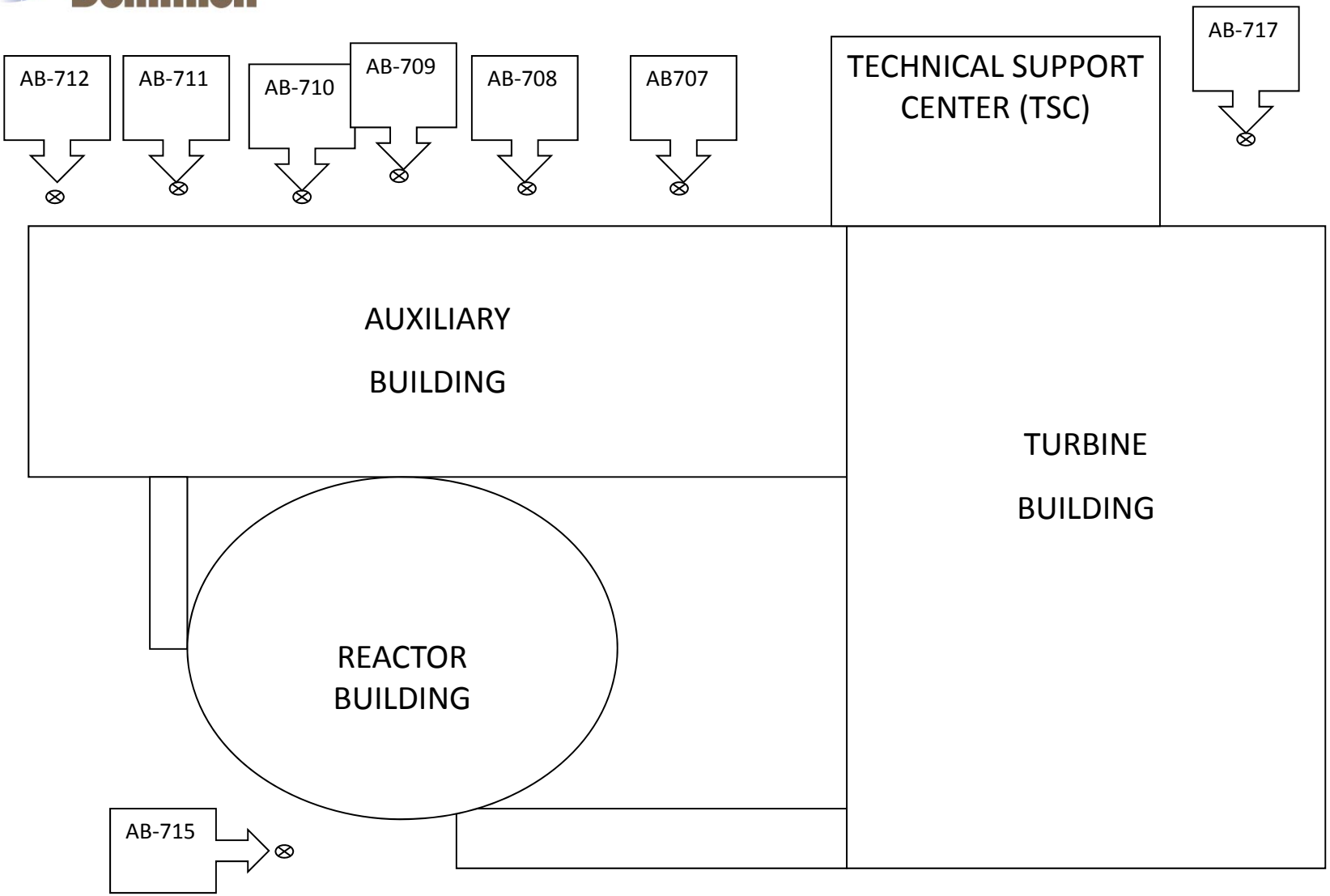


Back



NOTES:

1. THE ELECTRICAL EQUIPMENT IN SCOPE OF LICENSE RENEWAL FOR RESTORATION OF OFFSITE POWER IS SHOWN BY DOTTED LINES.
2. THE NORMALLY OPEN (N.O.) OR NORMALLY CLOSED (N.C.) POSITION OF 4160-VOLT AND 480-VOLT BREAKERS ARE INDICATED FOR NORMAL PLANT OPERATION.


AB-712
AB-711
AB-710
AB-709
AB-708
AB707
TECHNICAL SUPPORT CENTER (TSC)
AB-717
AUXILIARY BUILDING
TURBINE BUILDING
REACTOR BUILDING
AB-715

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Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Kewaunee Power Station (KPS)

Safety Evaluation Report (SER)
with Open Items

August 18, 2010

John W. Daily, Project Manager

Office of Nuclear Reactor Regulation

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Presentation Outline

- Overview of KPS license renewal review
- SER Section 2, Scoping and Screening review
- The Region III License Renewal Inspection
- SER Section 3, Aging Management Programs and AMR results, with Open Items
- SER Section 4, Time-Limited Aging Analyses (TLAAs)

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Overview (LRA)

- License Renewal Application (LRA) submitted August 12, 2008
  - Applicant: Dominion Energy Kewaunee, Inc. (DEK)
  - KPS located in Kewaunee county, Wisconsin
  - Westinghouse 2-loop PWR Design
  - 1772 MWt, 590 MWe
  - Facility Operating License No. DPR-43 expires December 21, 2013

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Audits and Inspections

- Scoping and Screening Methodology Audit
  - March 10 – 13, 2009
- Aging Management Program (AMP) Audits
  - June 9 – 12, 2009
  - October 19 – 20, 2009 (Audit of the revised Work Control Process AMP)
- Region III Inspection (Scoping and Screening & AMPs)
  - August – September 2009

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Overview (SER)

- Safety Evaluation Report (SER) with Open Items issued July 16, 2010

- SER contains 4 Open Items (OIs):
  - Use Of FatiguePro™ Software in Metal Fatigue Calculations (OI 3.0.3.2.20-1)
  - Ni-Alloy Steam Generator Divider Plate Cracking due to PWSCC (OI 3.1.2.1.7-1)
  - Incorporating recent operating experience for buried and underground piping and tanks (OI 3.0.3.2.4-1)
  - Work Control Process Program Issues (OI B2.1.32-1)

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SER Section 2 Summary

Structures and Components Subject to Aging Management Review

- Section 2.1, Scoping and Screening Methodology
  - Methodology is consistent with requirements of 10 CFR 54.4 and 54.21
- Section 2.2, Plant-Level Scoping Results
  - Systems and structures within the scope of license renewal are appropriately identified in accordance with 10 CFR 54.4
- Sections 2.3, 2.4, 2.5 Scoping and Screening Results
  - SSCs within the scope of license renewal are appropriately identified in accordance with 10 CFR 54.4(a), and those subject to an AMR in accordance with 10 CFR 54.21(a)(1)

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Kewaunee Power Station License Renewal Inspection

Caroline Tilton

RIII Inspection Team Lead

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Regional Inspection

- IP 71002
  - 2 weeks: Aug 17 – 21 & Aug 31 - Sep 4, 2009
  - 5 inspectors and 1 observer
  - Scoping & Screening
  - Aging Management Programs

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Inspection Results

- Visual Observation of Plant Equipment
  - Walkdown of portions of 10 systems
- Scoping & Screening
  - Walkdowns of selected systems
  - Drawings had adequate division between safety and non-safety
  - Non-Safety Affecting Safety was Acceptable
- AMPs – Team reviewed a sampling of 24/34 AMPs
  - Program Documents & Procedures
  - Walkdowns including Containment during hot shutdown.
  - Interviewed Plant Personnel

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AMPs Discussion

- **Aging Management Program (AMP) Changes**
  - Buried Piping and Tanks Inspection Program (procedure revision)
  - Compressed Air Monitoring Program (supplemented LRA)
  - External Surface Monitoring Program (modified requirements)
  - Metal Fatigue of Reactor Coolant Pressure Boundary (procedure updated to include component)

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Operating Experience

- Operating Experience Review
  - System Program Results
  - Operating Experience related procedures and documents
  - Corrective Action Reports for Prior SSC Problems, associated with the AMPs reviewed

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Inspection Conclusions

Overall

- Scoping of non-safety SSCs and application of the AMPs to those SSCs was acceptable
- Documentation supporting the application was auditable & retrievable
- Based on the review of the selected samples, our inspection results support a conclusion there is reasonable assurance that the effects of aging will be adequately managed

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SER Section 3

3.0.3 – Aging Management Programs

34 Aging Management Programs (AMPs) presented by applicant and evaluated in the SER

	Plant specific	Consistent with GALL	Consistent with exception	Consistent with enhancement	With exception & enhancement
Existing (28)	1	8	7	8	4
New (6)	0	5	0	0	1

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SER Section 3 Open Items – Summary

Four Open Items were identified during staff review:

- Applicant's use of FatiguePro™ in metal fatigue calculations
- Potential Cracking in Ni-Alloy Steam Generator Divider Plate due to PWSCC
- Incorporation of recent Industry OE for Buried and Underground Piping and Tanks
- Various Issues in Work Control Process AMP

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SER Section 3 Open Items

Metal Fatigue of Reactor Coolant Pressure Boundary

OI 3.0.3.2.20-1:

- Applicant's use of FatiguePro™ in stress-based portion of metal fatigue calculations did not incorporate all portions of stress tensor for calculations on 2 RCS components
- Applicant agreed to perform updated, confirmatory fatigue calculations for the 2 affected components
- Submitted results to staff on June 1, 2010
- Staff in process of reviewing the results

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SER Section 3 Open Items

Cracking Due to PWSCC (Steam Generator Divider Plate)

OI 3.1.2.1.7-1: Cracking due to PWSCC for Ni-Alloy SG Divider Plate

- Extensive cracking due to PWSCC has been identified in some European SG divider plates, even with proper primary water chemistry
- Cracks in those SGs were found in stub-runner/divider plate region
- Staff concern of possible propagation into tubesheet cladding, tubesheet or into SG-RCS channel head
- Applicant provided RAI response July 22, 2010.
- Staff in process of evaluating applicant's response

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SER Section 3 Open Items

Buried Piping and Tanks Inspection

OI 3.0.3.2.4-1:

- Staff has noted a number of recent industry events involving leakage from buried and underground piping/tanks
- Staff is concerned about continued susceptibility to failure of buried/underground piping within the scope of license renewal
- Staff issued RAI on May 27, 2010, requesting applicant to:
  - Discuss all instances of leakage/ adverse conditions identified at KPS and how applicant's AMPs have been revised to address (past 5 yrs)
  - Discuss how the AMPs will address recent industry OE concerning aging effects in buried, underground, and limited access piping and tanks
- Applicant provided response July 22, 2010.

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SER Section 3 Open Items

Work Control Process Program Issues

<u>OI B2.1.32-1</u>:

- Staff has noted a number of issues in newly-submitted Work Control Process AMP
- Staff issued an RAI April 14, 2010, to request applicant explanations/justifications on these issues:
  - The program does not completely specify minimum percentages/ sample sizes/ inspection frequencies of populations
  - The OE examples create uncertainties as to whether the AMP will effectively manage the aging effects
  - Applicant's Commitment 25 was somewhat ambiguous
- Applicant's response received, staff in process of evaluating

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SER Section 3.5

Section 3.5.2.2.2: Aging Management of In-Scope Inaccessible Concrete (below grade)

Parameter	Acceptance Criteria	KPS (2007-2009)	
		Min	max
pH	>5.5	7.10	8.17
Chlorides	<500 ppm	34 ppm	1240 ppm
Sulfates	<1500 ppm	36 ppm	422 ppm

Commitment: (Commitments 44 & 45) Take additional core samples to monitor concrete below ground level.

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SER Section 4.2

SER Section 4.2.3: Pressurized Thermal Shock

Section 4.2.3 PTS Limits for Reactor Vessel Materials Due to Neutron Embrittlement

RV Beltline Region Location (LRA Table 4.2-3)	RT_{PTS} (Deg. F) (60 years, 52.1 EFPY)	RT_{PTS} Acceptance Criteria (Deg. F)
Int. Shell-Lower Shell Girth Weld	297.5 °F[1]	≤ 300 °F
Upper Shell Forging	164 °F	≤ 270 °F
Intermediate Shell Forging	146 °F	≤ 270 °F

[1] – Calculated value determined using methodology approved by staff SE dated May 1, 2001, as exemption to 10 CFR50.61

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Conclusion

On the basis of its review and **pending satisfactory resolution of all open items**, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Kewaunee Power Station.

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Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Kewaunee Power Station (KPS)

Safety Evaluation Report (SER) with Open Items
Extra Slides (If Needed)

August 18, 2010

John W. Daily, Project Manager
Office of Nuclear Reactor Regulation

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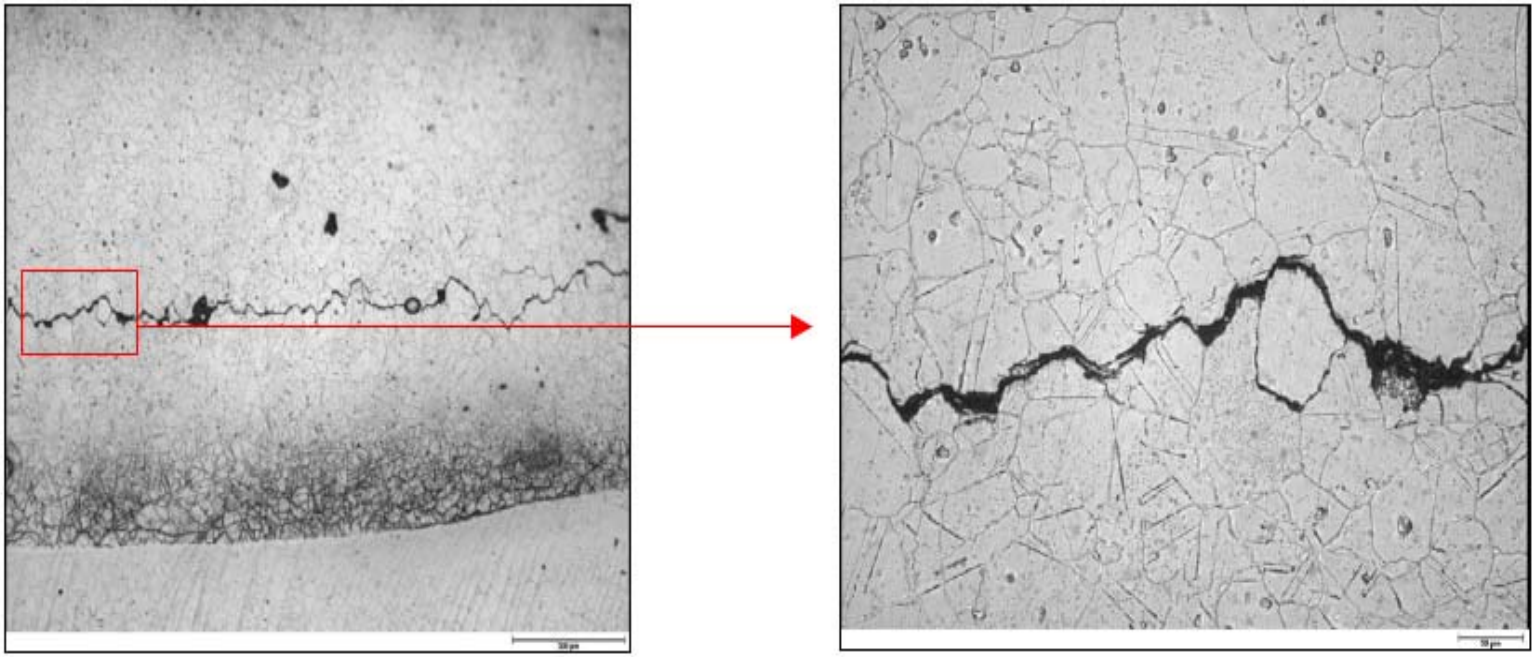
From EDF Presentation – Sept. 2006



Intergranular path characteristic of PWSCC of alloy 600

EDF

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From ASN Presentation – Sept. 2006

AUTORITE DE SURETE NUCLEAIRE

STRESS CORROSION CRACKING OF THE INCONEL ZONES: POINT OF VIEW OF THE FRENCH NUCLEAR SAFETY AUTHORITY

Bureau de Contrôle des Chaudières Nucléaires

- 2005: PT results