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Susquehanna Plant License Renewal

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

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MEETING

+ + + + +

WEDNESDAY

APRIL 1, 2009

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ROCKVILLE, MD

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The Subcommittee convened in Room T2B3 in the Headquarters of the Nuclear Regulatory Commission, Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., Dr William Shack, Chair, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

WILLIAM J. SHACK, Chair

JOHN D. SIEBER

SAM ARMIJO

JOHN W. STETKAR

MARIO V. BONACA

SAID ABDEL-KHALIK

OTTO L. MAYNARD

CHARLES H. BROWN, JR.

HAROLD B. RAY

CONSULTANT TO THE SUBCOMMITTEE PRESENT:

JOHN J. BARTON

NRC STAFF PRESENT:

PETER WEN, Designated Federal Official

BRIAN HOLIAN

DAVID PELTON

EVELYN GETTYS

GLENN MEYER

SAM LI

JAY ROBINSON

BILL ROGERS

ERACH PATEL

SAM LI

SIMON SHENG

CHUANG YANG

ALSO PRESENT:

PHIL BRADY

NICK D'ANGELO

DUANE FILCHNER

DAVE FLYTE

ROSS GARDNER

MARK HAGER

JOHN KRAIS

MITCH McFARLAND

RICK PAGODIN

DALE ROTH

GARY STEVENS

BRUCE SWOYER

MASSOUD TAFAZZOLI

JEFF WEIK

JIM WILLIAMS

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

8:29 a.m.

CHAIR SHACK: The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I am Bill Shack, Chairman of the Susquehanna Plant License Renewal Subcommittee.

ACS members in attendance are Mario Bonaca, Jack Sieber, Otto Maynard, Sam Armijo, Harold Ray, maybe, John Stetkar, Charles Brown and our consultant John Barton.

Peter Wen of the ACRS Staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the license renewal application for the Susquehanna Stream Electric Station Units 1 and 2, the Draft Safety Evaluation Report and associated documents. We will hear presentations from representatives of the Office of Nuclear Reactor Regulation and the applicant PPL Susquehanna. The subcommittee with gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full committee.

The rules for participation in today's meeting were announced as part of the notice of the meeting previously published in The Federal Register

on March 16th, 2009.

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

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

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

We will now proceed with the meeting and I call upon Brian.

Said Abdel-Khalik reminds me that he is, in fact, present and I didn't realized. Oh, Harold is definitely here.

We will now proceed with the meeting and I call upon Mr. Brian Holian of the Office of Nuclear Reactor Regulation to introduce the presenters.

MR. HOLIAN: Thank you. It's our pleasure

to be here again for a Subcommittee on Susquehanna. My name's Brian Holian. I'm the Director of License Renewal.

I'd like to do some brief introductions and then just have a quick opening comment on Susquehanna Draft SER.

To my left is Mr. Dave Pelton. He's the Branch Chief for License Renewal and responsible for the Susquehanna plant among others. He'll also be here for the TMI plant this afternoon.

To his left is Evelyn Gettys, the Project Management for the Susquehanna project and to her left is Mr. Glenn Meyer, the Senior Reactor Inspector from the Division of Reactor Safety in Region I.

We have additional technical staff and branch chiefs in the audience to support our presentation later. I would like to mention a Branch Chief from Region I. Mr. Richard Conte is here also to support the inspection side of the house.

You know, the Susquehanna Plant Draft SER is -- just wanted to comment on a few items that aren't in it that the staff will touch after the licensee's presentation. One of the aspects that came out of the Inspector General Review of licensed general process was to increase our peer reviews over

a year/year and a half ago. So, we've been doing that and have technical reviewers reviewing our draft SERs even as they come to ACRS.

You'll notice in the staff slides we have a couple of confirmatory items and an issue on Boral that we continue to look at in the Susquehanna SER. We've verbally talked about all three of these issues that we'll talk about, but I'll mention them here prior to the licensee's presentation.

One -- the first two items are some confirmatory items. We're still reviewing data from Susquehanna that deals with cycle counting which is often an issue that we look at. So, the staff may have been looking at that or aspects of that and we're verifying some of their cycle counting.

We're also looking at an issue with dissolved oxygen in the metal fatigue calculations. Just verifying what they historically have for dissolved oxygen content and the calculations and the assumptions and how that compares to their tech specs.

And finally, another issue that's come up recently on several plants is the Boral issue and, you know, aging effects of Boral and Susquehanna also has that and that's an item the staff continues to look at and review with them.

So, I just wanted to mention those items. You'll hear them again in the staff's presentation, but I wanted to mention them before Susquehanna starts their presentation so the subcommittee's aware of that.

With that, I'll turn it over to Mr. John Krais, the Manager of Special Projects for Susquehanna.

MR. KRAIS: Thank you. Good morning. My name's John Krais. I am the Manager of Special Projects for PPL Susquehanna. Thank you for the opportunity to discuss the Susquehanna License Renewal Request.

With me here today are Rick Pagodin, General Manager of Engineering at Susquehanna; Nick D'Angelo, Manager of Station Engineering; Dave Flyte, License Renewal Lead Engineer who will be speaking to you later and we also have with us subject matter experts and the License Renewal Project Team including representatives from AREVA and Structural Integrity who assisted us in our license renewal application preparation.

Now, we would like to discuss the background and operating history of Susquehanna, major modifications and investments in that plant as well as

our License Renewal Team and schedule.

Dave Flyte will be presenting a scoping discussion, application of GALL, commitment process and topics of interest.

A little background on Susquehanna, Susquehanna's located in Northeast Pennsylvania approximately 20 miles southwest of Wilkes-Barre. The plant is owned by PPL Susquehanna LLC and co-owned by Allegheny Electric Cooperative. The licensee operator is PPL Susquehanna.

Susquehanna has two BWR units licensed up to 3952 megawatts-thermal and I'll discuss our current operation in a few slides.

Generator rating is 1300 megawatts-electric. General Electric is our NSSS supplier and Bechtel is our AE.

The ultimate heat sink is provided by a spray pond and turbine cycle cooling is provided by natural draft cooling towers with make-up water being pumped from the Susquehanna River.

Brief discussion of our operating history, construction permit for Susquehanna was issued in November of 1973 and the operating licenses were issued Unit 1 in July of 1983 and for Unit 2 in March of 1984.

We implemented a stretch power uprate of approximately 4.5 percent. That took us from 3293 megawatts-thermal to 3441 megawatts-thermal and that was implemented for Unit 2 in April of '94 and Unit 1 in February of '05.

Our measurement uncertainty recapture uprate of approximately 1.5 percent was completed in July of 2001. We submitted our license renewal application in September of 2006 and in power with that, our extended power uprate review occurred and we received the extended power uprate renewal in January of 2008. Extended power uprate took us to 3952 megawatts-thermal.

Our current license expires for Unit 1 July 17th of 2022 and then March 23rd of 2024 for Unit 2.

Some of our recent operating history at Susquehanna, our refueling outage 15 was completed in April 2008 and our first step EPU was implemented in May 2008. That first step increased our operating power levels from 3489 to 3733 and our full uprate to 3952 megawatts-thermal. In 2010, final installation of new reactor feed pump turbines. Unit 2, refueling outage 13 was completed in April of 2007 and we're currently on a record continuous run of 718 days.

MR. BARTON: Your refueling cycle is?

MR. KRAIS: Twenty-four months.

CHAIR SHACK: Now, which one of these units is got the instrumented stream dryer?

MR. KRAIS: Unit 1 has the instrumented stream dryer and we've --

CHAIR SHACK: Any interesting things occur when you implemented the first-step EPU?

MR. KRAIS: The response is as we expected. The first step for EPU for Unit 2 will be implemented in May of 2009. The increased power levels to 3733 megawatts-thermal and the full operate to 3952 will occur in 2011. Again, following the installation of the new reactor feed pump turbines.

These next two slides is a sampling of some of the modifications and improvements made at Susquehanna. These modifications are instead and have been evaluated for license renewal. Our plant modification process includes administrative requirements to insure that license renewal is considered and evaluated when designing and implementing mod.

For example, we have replaced feedwater heaters and moisture separator vanes based on inspection results from condition monitoring that

identified some degraded material conditions. Those are just some examples of --

CHAIR SHACK: Now, your hydrogen water chemistry is that with noble metal additions?

MR. KRAIS: That is not with noble metal additions.

CHAIR SHACK: Standard hydrogen water chemistry.

MR. KRAIS: That's correct.

MEMBER SIEBER: In this list, most of the items are wear and tear items, but the diesel is not. Why did you add extra diesel?

MR. BRADY: This is with the -- Susquehanna. The fifth diesel was added very early in the plant life. The issue is that we have basically a 72-hour LCO with a diesel out of service.

MEMBER SIEBER: Right.

MR. BRADY: It affects both units.

MEMBER SIEBER: Okay. That's --

MR. BRADY: So, we added a fifth diesel which we can substitute for any one of the original four diesels.

MEMBER SIEBER: Okay.

MR. BRADY: And not have to shut the plants down.

MEMBER SIEBER: Thank you.

CHAIR SHACK: You have a modification of your core shroud, too. Right? Or no, it's unrepaired?

MR. KRAIS: We do not have a modification on a core shroud.

CHAIR SHACK: Okay. What's the -- oh, okay. Maybe you'll talk about the condition of the core shroud sometime.

MR. KRAIS: We can touch on that. Yes. License renewal team -- project team was assembled and initiated in 2002 and our PPL and AREVA team was established in 2004.

Our license renewal team is engaged with the industry. We have members on the NEI License Renewal Task Force and the various discipline working groups since 2001. We've also observed audits and inspections at two peer plants and participated in four other license renewal peer reviews at other plants.

Our license renewal application was also reviewed by an independent industry group.

Plant subject matter experts including station system engineers and program owners are involved in the development of basis documents for

license renewal and review and have agreed to the aging management commitments and programs that our license renewal application contains.

License renewal schedule, license renewal was prepared in conjunction with our extended power uprate project and both projects are part of a special projects groups. The license renewal application was developed at EPU conditions and submitted in September of 2006.

Our EPU submittal occurred at approximately the same time, October of 2006, and the EPU occurred first.

Around January of 2007, our license renewal safety review was placed on hold pending completion of the EPU review and during this time, however, our environmental review continued.

Upon issuance of the EPU license in January of '08, the safety review resumed.

At this point in time, I'd like to turn it over to Dave Flyte who will discuss some details of the license renewal application.

MR. FLYTE: Thanks, John. Good morning, everyone.

I'd like to talk about some of the specific aspects of the license renewal process for

Susquehanna and the license renewal application itself including touching on scoping, how we use the GALL report in preparing the application, a little bit of -- just a brief touch on time-limited aging analyses and finally on this segment looking at the commitment process.

Scoping was preformed in accordance with industry guidance -- established industry guidance in NEI 95-10 Revision 6. For the non-safety effecting safety spacial interaction scoping, we used the conservative spaces approach. We did develop mechanical boundary drawings as a reviewer's aid. Mechanical boundary drawings showed all three categories of in-scope components. The (a)(1) safety related, the (a)(2) non-safety effecting safety and the (a)(3) regulatory -- regulated against.

MEMBER STETKAR: Dave.

MR. FLYTE: Yes.

MEMBER STETKAR: In the -- I read through the inspection -- the regional inspection report and they mentioned HPCI cables running through the Unit 1 turbine building that you determined did not have an affect on operation at HPCI. What are those cables?

MR. FLYTE: They're actually cables that are running through the Unit 2 turbine building and

they're the cables for the suction swapover for HPCI on the low condensate storage tank level.

MEMBER STETKAR: And that's not credited in the licensing analysis? The swapover is not?

MR. FLYTE: The swapover is credited, but we entered that situation into our Corrective Action Program, did an evaluation on it and we determined that the only thing that could impact those cables is a high-energy line break and if you look at the -- the help evaluation, it does not rely on this, on the swapover. So, from that perspective with the only thing that could impact them, you know, it didn't matter that they were in the turbine building.

MEMBER STETKAR: Okay. Thanks.

MR. FLYTE: In aging management reviews, we made extensive use of the GALL report. Guidance in NEI-95-19 which basically comes down to identifying all the various combinations of component material, environment and aging effects that are present for the passive components in the scope of license renewal.

We compared those lists of combinations to the aging management review tables in GALL and found that we were -- had about an 82 percent match between the two lists.

The items that are left off the table

there that are consistent but equally divided among three major categories. The first of which is where the environment for a given component and material is not in GALL and about two-thirds of those that we found actually turn out to have no aging effects that require management. So, they weren't a big issue there.

You know, one example would be copper cooling coils in a heat and ventilation system that are exposed to ventilation environment. No aging effect requiring management.

Another grouping about equal in size was -- with the aging effect was not in GALL for complement material environment combination. So, we identified things that weren't specifically listed in GALL. A lot of these turned out to be copper components cracking in a treated water system.

And the leading group was where the GALL aging effect, GALL identified an aging effect and our aging management review didn't show that aging effect on over half of these that happened to be concrete and for them, we have a confirmatory program anywhere. We have a program credited for managing that and confirming that there's no aging effect. So, even though we included AMR, that is not the program that

is there.

CHAIR SHACK: So, you had admiralty brass or some components in places where GALL didn't expect to find those materials?

MR. FLYTE: Yes, that's -- I think that's a good characterization.

CHAIR SHACK: Okay.

MR. FLYTE: The other place that we made extensive use of the GALL report is in the evaluation of the aging management programs that are credited for license renewal. You can see about 20 of those -- well, 20 of those programs are existing programs that require no change. So, they lined up well with the GALL programs or the evaluations that were done in GALL.

Another 12 of those programs are existing programs that we saw we needed to make some kind of enhancement in order to get them to align with the GALL evaluation. So, we committed to those enhancements.

And lastly, there's about 19 new programs that were identified for license renewal. Ten of which are one-time inspections.

Overall if you look at the split, you can see that the majority of the programs are GALL related

or they have a GALL counterpart and we do have only four plant specific programs.

MEMBER STETKAR: Dave. Another question on this fuel oil tank program. Your fuel oil tanks are lined with something or other. What are they lined with? It's the fuel oil storage tanks. Not the oil tanks.

MR. FLYTE: Yes. Bill, do you know that -- do you know what they're lined with? I know they're lined, but I --

MEMBER STETKAR: There was an exception taken that you couldn't do measurement of the thickness of the bottom of the tanks because you'd have to remove the lining and I was curious what --

MR. BARTON: Was that about the lining or was that a coating?

MR. FLYTE: A coating. A coating.

MR. BARTON: On the outside of the tank.

MEMBER STETKAR: No, I think it's on the inside.

MR. BARTON: The inside.

MR. FLYTE: Inside.

MR. BARTON: Okay.

MR. ROTH: Dale Roth. I'm the Supervisor of Program and Testing at Susquehanna.

Yes, they are coated. They just have epoxy coding.

MEMBER STETKAR: Okay.

MR. D'ANGELO: Let me just -- the coding of the tanks are coated with a Carbomaster 14 on the interior.

CHAIR SHACK: Which is what?

MR. D'ANGELO: I don't know. Not really sure.

MEMBER STETKAR: It's called Carbonmaster 14.

MR. D'ANGELO: Carbomaster.

MEMBER STETKAR: Carbomaster?

MR. D'ANGELO: Fourteen.

MEMBER STETKAR: All right. Hold on a second. I was curious. The rationale you said well, we can't -- we're going to take credit for measuring the potential thinning of the fuel oil day tanks because that will tell us whether there's corrosion going on in the fuel oil storage tanks.

I was curious about that because I wasn't quite clear how the direct correlation was made between those. It kind of depends on where the fuel oil transfer pumps take suction from the fuel oil storage tanks. If they take suction directly from the

bottom, I can see that rationale, but oftentimes they don't. So, you can get a good stagnant layer of whatever at the bottom of the tank and you don't really mix up.

So, where do your transfer pumps actually take suction. Is it relatively above the bottom of the tank?

MR. D'ANGELO: Yes, the suctions do come off the bottom of the tank.

MEMBER STETKAR: Oh, directly off the bottom or --

MR. D'ANGELO: They're elevated off the bottom on a pedestal.

MEMBER STETKAR: Okay. So, there could be a stagnant layer of fuel and contaminants at the bottom of the storage tank that you'd never -- you never really deliver that stuff into the day tank.

MR. D'ANGELO: That is correct. However, we do do sampling on the fuel oil tanks and we do sample down to the bottom of the tank.

MEMBER STETKAR: To the bottom. Okay. Good.

MR. D'ANGELO: Yes.

MEMBER STETKAR: Thank you. Sorry.

MR. BARTON: Since you can't use UT, what

is your program for visual inspections of the tanks? Is it a visual or what? What is your aging program for those tanks? For the storage tanks?

MR. FLYTE: Dale, can you address that question?

MR. ROTH: Yes, this is Dale Roth again. Yes. We use -- we have a periodic inspection of the tank. I think it's every ten years and we do a visual inspection of the coating for integrity to look for any degradation. A good coating translates into a good solid structurally sound tank.

MEMBER ABDEL-KHALIK: When was the last inspection? Major inspection?

MR. ROTH: We just completed inspection of one of the diesels this summer. So, I'm not sure exactly which of the five, but we do them, I think, every ten years and I'm not sure of the exact schedule, but we just completed one this summer.

MEMBER ABDEL-KHALIK: Everything was fine.

MR. FLYTE: I would like to talk briefly about the exceptions that we found when we did the comparison with the GALL evaluations.

The programs are consistent with GALL with a few exceptions. The exceptions don't mean that there's a particular problem. It just means we've

taken a different approach and our evaluation did conclude in all cases that aging would be effectively managed.

I think the number of the exceptions are pretty typical of what we've been seeing across the industry. Ours are in the areas of scope differences between the programs, use of alternative inspection or monitoring methods and differences in the parameters we look at, how we detect aging effects and some of the preventive actions that we take.

MEMBER SIEBER: How many exceptions did you say you --

MR. FLYTE: There's a total of 13 exceptions.

MEMBER SIEBER: Okay.

MR. BARTON: On your aging management program for reactive S internals, section on cracking due to cyclic loading stainless steel BWR jet pump sensing lines, if you take exception to instrumental lines inside the vessel because they do not perform an intended function, now, these are jet pump instrumentation lines, you know, what are these lines used for and aren't they subject to cracking and becoming loose parts?

MR. FLYTE: I believe Mitch can provide a

response to that.

MR. MCFARLAND: This is Mitch McFarland with the Washington Oil Team. We have evaluated that situation. I'm sorry. Mitch McFarland with the Washington Oil Team.

We did evaluate that situation inside the vessel. The jet pump sensing lines are used for information but are not credited for accident mitigation or required for accident mitigation.

We've looked into -- there's an evaluation in BWR VIP 06 DSER for that. I believe it is ADAMS number MC7448 that evaluated the impact of those becoming loose parts and determined that they would not be able to leave the shroud.

MR. BARTON: Okay. Thank you.

MR. FLYTE: The next area I'd like to touch on briefly is time-limited aging analyses. We identified TLAAs in accordance with guidance that we find in standard renew plans for license renewal, NUREG-1800 and the guidance in NEI 95-10. TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1).

CHAIR SHACK: Just on there, I mean you're environmental fatigue is fairly sensitive to your dissolved oxygen levels and your measurements of dissolved oxygen levels are made where?

MR. WEIK: This is Jeff Weik, Mechanical Lead for the PPL Project Team.

I'm not exactly sure of where they pull the samples. The information that we have from our chemistry group that we -- in fact, that we used in the calculations for the EAF results were such that we requested information from the chemistry group that would be indicative of the lower vessel region for reactor water and we also pull samples for the feedwater system that are indicative of the feedwater returning the reactor vessel.

CHAIR SHACK: Well, it is sort of -- I mean, you know, the feedwater's going to have a different oxygen. I mean typically the recirculation lines are going to have much lower oxygen levels than inside the vessels and so, it does sort of become important exactly where those samples are being taking from if you're taking credit for those low oxygen levels.

MR. WEIK: Well, for the reactor itself, the locations of the reactor vessel, we are using the reactor water values provided to us by chemistry. Currently --

CHAIR SHACK: Are those measurements or are those projected from some hydrogen water chemistry

novel?

MR. WEIK: Those are daily measurements taken, daily samples and we use the reactor water values which before hydrogen water chemistry were typically in the range of 250 to 280 parts per billion and following hydrogen water chemistry, they're not typically -- they're maintained less than two. They're typically running well under two.

The feedwater levels have shown that they are consistently in the 20 to 50 part per billion range and we actually maintain them above 30 parts per billion now under hydrogen water chemistry.

CHAIR SHACK: Those vessel levels sound a little low to me for normal water chemistry if they're actually being made inside the vessel.

MR. D'ANGELO: The reactor water cleanup influence system is where we get our dissolved oxygen samples. That ultimately takes a suction from the recirc loops and bottom head drain.

CHAIR SHACK: Okay. But, then how are you -- well, does that bound -- that doesn't bound all the oxygen levels for all the components.

MEMBER SIEBER: No.

CHAIR SHACK: What happens to your fatigue analyses for, you know, somewhat higher oxygen levels

in the reactor internals?

MR. PAGODIN: Bill, this is Rick Pagodin.

Again, I think this is an issue that we've recently just started looking into with the staff. We were going through and getting additional data and we're providing -- we have some -- we've had some discussions on that. I think this is an area where we need to finish that review and have all of that data collected for both us and the staff to look at.

MR. FLYTE: The license renewal process for Susquehanna resulted in identification of 59 new regulatory commitments. Fifty-one of these are for implementation of aging management programs be it either continuance of a program, putting a new program in place or enhancing an existing program.

These commitments have all already been entered into the Susquehanna commitment tracking process. They've been assigned to an individual at the station for implementation.

The commitment process -- commitment tracking process has oversight by our Nuclear Regulatory Affairs Group and that's just another vehicle to make sure that they get implemented.

From this, I'd like to move into several topics of interest. First is an inspection of a

piping vault that includes -- is an underground vault. Includes RHR service water and ESW emergency service water piping. This was requested by the Region I inspectors when they were onsite for the inspection during last August. It couldn't be arranged to occur during the inspection. So, one of the inspectors returned to the site later on to witness when the vault was opened.

Part of the motivation to opening the vault was to insure that the information we assumed in the evaluation for the aging management review was correct. That the environment inside the vault was what we assumed.

Yes, sir.

MEMBER STETKAR: If I recall from the inspection report, this vault was not originally included in your inspection program. Is that correct? This vault was subsequently added after the inspection.

MR. FLYTE: That is correct. That is correct.

MEMBER STETKAR: Requested to look at.

MR. FLYTE: Yes.

MEMBER STETKAR: Okay. Thanks. I just wanted to make sure I remembered the same vault.

MR. FLYTE: Yes, it's the same one.

Conditions, again, we conditions in the vault to be dry because design drawings show that both the lid and the piping penetrations were sealed -- had seals. We did open the vault and conditions were as expected.

We performed some inspections of the coatings, wrapping of the pipe and the general -- and found conditions to be acceptable. No significant degradation.

The next topic of interest is underground medium voltage cables. Susquehanna has both 15 kV and 05 kV cables that are in scope of license renewal and have segments that run in underground duct banks. I want to talk about the 15 kV cables first. They're in non-safety related circuits and they're in scope of license renewal for the station blackout recovery. Talk about these in two segments.

The first segment is from the low side of the startup transformers and runs into the turbine building. There's a stretch that goes underground. Includes five manholes and from past inspections of those manholes we observed submerged cables in two of those manholes.

The other segment of this circuit is from

the reactor building out to the engineered safeguard services transformers. So, a very short one. No manholes in that underground run. So, obviously, no inspection to see about water. Had no operating experience.

The fact that we've had cables submerged in water, these are energized greater than 25 percent of the time. They're the offsite power supply sources. So, therefore, since we have the stressors present to require or suggest an aging management program, so, we committed to the aging management program for these cables for license renewal which results in periodic testing and inspection, pumped down to the manholes to keep the cables from being exposed to standing water.

MEMBER BROWN: How often do you inspect them? Are you going to inspect them? I mean it's 15 kV cables buried in water. It's not high on anybody list to maintain.

MR. FLYTE: Phil Brady can address that question.

MR. BRADY: Phil Brady. I'm the Supervisor of Retro and INC Design at Susquehanna.

The inspection process, after we had done some inspections of looking at the water for

approximately an eight-month period at Susquehanna, measuring the water level intact in each of these manholes and draining them down, we have established pump-down frequencies to, in fact, assure ourselves that we'll maintain the water level below any of the medium voltage cables in the future.

Obviously, as we continue that process, we'll look further as far as if we'll have to make any refinements to that number based on our actual experience as we go into it, but our plan is --

MEMBER BROWN: So, you inspect to see where that level -- they're obviously refilling.

MR. BRADY: That's correct.

MEMBER BROWN: So, you try to determine what the periodicity of the refilling was and then do pumping to keep them below those levels?

MR. BRADY: That is correct.

MR. BARTON: Where did you incorporate this? Is it in your PM program or what?

MR. BRADY: Yes, it is. It's in our PM program. We have those for the various offsite power supply cables coming in from T10 and T20.

MEMBER MAYNARD: Have you found that the rate of the water intrusion -- is it related to weather in anyway or is it just fully steady over a

given period of time?

MR. BRADY: The eight-month period did include some fairly significant rainfalls at different times during the course of the year. We did look at that. We're not able at this point to make the direct correlation that it is just rainwater. We know the manholes are not necessarily sealed as an entity. So, it is possible we still have some groundwater that's also coming into the manhole systems.

MEMBER STETKAR: Your mentioned an eight-month period that you monitored things. Had you checked for water before that eight-month period?

MR. BRADY: No, the only time -- at that time, the only times we would have been going into the manholes would have been if we were doing some physical work activity, maintenance activities. Things along that line would have been our only time at that point under these particular manholes.

MEMBER STETKAR: As you know, I mean this is not necessarily specific license renewal issue. It's a current --

MR. BRADY: No.

MEMBER STETKAR: -- it's a current issue. So, I know that a lot of these topics will get resolved as part of the current licensing basis, but

I'd -- have you done any testing of the insulation on those cables since --

MR. BRADY: Yes, we've --

MEMBER STETKAR: You have.

MR. BRADY: Yes, we have. All of our -- our cables initially were all done under double testing during the initial construction and startup phase.

MEMBER STETKAR: Initial.

MR. BRADY: And we have, in fact, in many of these cases, our safety-related cables, we've had on a frequency of approximately about a four-year frequency to do a double test on those cables and verify the insulation.

The outside power sources, we, in fact, have, in fact, instituted a program. We're also on a four-year frequency under a PM program to now do double testing on those cables.

MEMBER STETKAR: That's double testing?

MR. BRADY: Double testing. That's correct.

MEMBER BROWN: For the uninitiated like me on what doubles, is that just twice the voltage?

MR. BRADY: No. No. No. Double testing is looking at a power factor testing.

MEMBER BROWN: Oh. Okay.

MR. BRADY: It's looking at the actual insulation from a power factor standpoint.

MEMBER BROWN: Okay.

MR. FLYTE: A typical grouping of cables that's included with the scope of license renewal meeting voltages is the 5 kV and these are safety related cables and the circuits that they're involved with are emergency diesel generators, the RHR service water and the emergency service water systems.

The underground duct bank run for these includes ten manholes. Previous inspections of these ten manholes did not show any cables -- meeting voltage cables being submerged.

These cables are also energized less than 25 percent of the time. So, we concluded from our aging management review that they don't meet either of the criteria established in the GALL report for having the stressors that would require an aging management program and, therefore, there's no additional commitment for a license renewal aging management program for these cables.

MEMBER STETKAR: Your ESW pumps don't normally run. I don't know Susquehanna. So, I -- they're normally a standby?

MR. D'ANGELO: That's correct.

MEMBER STETKAR: Okay.

MEMBER BROWN: You do inspect even though you -- is there -- I presume there's an inspection frequency for these. Even though you typically don't find them, you just don't want away and ignore them. Right?

MR. FLYTE: Yes, I'll let Phil address that.

MR. BRADY: Yes, again, this is Phil Brady.

Yes, we do inspect those manholes as well and are using the operating experience that we gained through that similar eight-month period to look at periodicity to go into those and actually pump them down and verify the water is, in fact, being maintained below the medium voltage cables.

Even though as Dave pointed out, by the GALL report, they are not energized more than 25 percent.

MEMBER BROWN: I understand that.

MEMBER STETKAR: Phil, do those manholes also contain non-safety related medium voltage cables that are normally energized? Like what do they call your normal surface water pumps, you know, that are

run in the same --

MR. BRADY: We do have -- I'd have to look at it. We do have cables that do come out of our building going down to the river intake structure down the Susquehanna River that are, in fact, non-safety related and they're 15 kV cables as well and, in fact, are energized on a continuous basis and, in fact, we are monitoring one of the -- those two cables running down to that intake structure because we do know that at the river those cables have been subjected to water on a continuous basis because of the water table near the river quantity. So, we are monitoring those and doing double testing. In fact, our frequency on those, we're testing right now on a yearly basis.

MEMBER STETKAR: Do they run through the same ducts? The same cable --

MR. BRADY: You know, not on the same trays, but --

MEMBER STETKAR: No. No. Through the same cable ducts as the safety related cables. Do you know?

MR. BRADY: I believe in front of the diesel generator building, they do. I think they're on separate sides of the manhole is the way we separated those, but they, in fact, run through it

because then the duct bank continues down from that location down toward the river.

MR. FLYTE: The last item of -- topic of interest that I'd like to touch on is scoping that was done for station blackout recovery. Grounding for the outside power supplies is established at this point for the latest staff guidance.

Moving out from the plant, out from the startup transformers, in fact, toward the transmission system, this includes the overhead transmission lines between the startup transformers, structures that support the out into the first breakers that you get to in the switchyards and that includes circuit breakers at the 230 kV level in three switchyards.

MR. BARTON: Let me ask you a question. Do you have an overhead you can show the station blackout arrangements so we can follow your description of how this is designed?

MR. FLYTE: In fact, we do and I'd ask Phil if you can just walk us through this. Just explain the layout here.

MR. BRADY: Again, this is Phil Brady.

When you look at the slide, basically, the connection on the top left-hand part of the slide is coming from a T-10 ring bus. That's one of our

sources of offsite power into our startup transformer T10. So, that's one of the connections.

We have a two-breaker connection up in that switchyard that is part of the SBO scope.

Our T20 source is off of a -- it's tapped off of a line which goes between our 230 kV switchyard which is across the river on the east side of the Susquehanna River and also has a breaker connection coming from an auto-transformer from our 500 kV to 230 kV. We use that breaker as the breakpoint on the connection.

So, again, one breaker off of the auto-transformer, two over in the 230 kV switchyard across the river and two in the T10 switchyard. Associated with the T10.

MEMBER BONACA: Could you comment on containment shelf, the conditions of the shelf?

MR. FLYTE: Thanks, Phil. We're done.

Yes, the -- Bruce, could you just comment on the condition of the containment liner?

MR. SWOYER: This is Bruce Swoyer, Design Engineer in Susquehanna.

You would like to know the suppression pool containment liner status. Correct?

We have done inspections on both units.

As a matter of fact, the last inspection was done in 2007 and we have had divers, NDE-qualified divers go in and do a visual inspection on the liner and we found no holes that were problems.

MEMBER BONACA: Have you experienced advance of the liquid over the --

MR. SWOYER: No, we have not.

CHAIR SHACK: Just coming back to your hydrogen water chemistry, since you sort of credit the hydrogen water chemistry in the fatigue analysis, does that mean that you're crediting hydrogen water chemistry operation for the extended license period?

MR. FLYTE: Gary, could you address that please?

MR. STEVENS: This is Gary Steven Structural Integrity.

The answer is yes. I think similar to the other evaluations you've seen for the other plants, there's an assumed duty going forward for the hydrogen water chemistry system. So, there's a time averaged -- over the 60-year life of the plant, there's a time averaged chemistry assumed that considers normal water chemistry prior to hydrogen water chemistry implementation. What the availability of the system has been since implementation and then an assumed

level going forward.

CHAIR SHACK: Just -- your Commitment 60 seems to address most of the questions associated with the FatiguePro software, but since we have Gary here and he understand this, can you explain what you did to benchmark FatiguePro so far? I wasn't quite sure exactly what you did.

MR. STEVENS: Susquehanna has the advantage of -- and they've had 20 years experience with FatiguePro. Originally when it was developed and we're talking about the stress-based fatigue locations here that are on two components, the feedwater nozzle, both the safe in and the nozzle foraging end, and the CRD penetrations.

Originally when it was developed, it was benchmarked up against the design basis NB-3200, you know, stress reports and how that was done is on two items. Number one, the stress intensity predictions that were coming out of FatiguePro were matched up against those predicted for design transients and then also, it was -- the fatigue usage itself was looked at to make sure that was what coming out of FatiguePro was consistent or bounding compared to those stress reports.

CHAIR SHACK: Okay. So, FatiguePro

doesn't take credit for doing a finite element analysis that gives lower stresses than your design methods would. You just scale the results back up.

MR. STEVENS: Correct.

CHAIR SHACK: Is that standard or is that a Susquehanna implementation feature?

MR. STEVENS: It's fairly standard. Not all plants have done that extensive of a benchmarking. It's becoming more standard.

CHAIR SHACK: Yes, I can understand that.

MR. STEVENS: This was done from the beginning at Susquehanna. So. And part of that was due to they were one of the first plants to implement FatiguePro. So, it was -- I think there was a lot more rigor put in in the early days to substantiate the initial, you know, versions of the program that were just recently developed.

MR. FLYTE: We passed over a question earlier about the condition of the course route.

CHAIR SHACK: Yes.

MR. FLYTE: At this time, we'd like to pick that up. If Bruce could address that.

MR. SWOYER: This is Bruce Swoyer.

Both course routes have cracking on the horizontal welds. We have done plant-specific

analysis on that cracking in accordance with the BWR VIP requirements and have established an inspection program again in accordance with the BWR VIP and the calculations.

CHAIR SHACK: Okay. How extensive is that cracking?

MR. SWOYER: The most extensive crack is in Unit 1, the H4, the midline. If you want to put that so everyone can see the --

MR. FLYTE: We have a slide here that shows the profile of the shroud.

MR. SWOYER: Right. Mid H4 Unit 1, the average crack is .6 inches. Our shroud is 2 inches thick.

CHAIR SHACK: And how long is it?

MR. SWOYER: It's approximately 60 percent around the circumference.

CHAIR SHACK: Big.

MR. SWOYER: Yes, sir.

CHAIR SHACK: I presume that was there before the hydrogen water chemistry was implemented.

MR. SWOYER: That is correct, sir, and in 2000 just prior to our initiating hydrogen water chemistry, we had done an inspection on that particular weld in Unit 1 and at that time, the

average crack depth was .5 and in 2004, we inspected it again and the crack depth went up to .6 and we will be doing an inspection again in 2010 on that weld.

CHAIR SHACK: Now, did you notice any differences in extension of the crack?

MR. SWOYER: The crack did grow, but again, the extension wasn't as great as it had been before hydrogen water chemistry.

But, again, in my opinion, the extension is more due to the cold work that was applied to the shroud. It's the depth that I think that the hydrogen water chemistry is affecting. The BWR VIP, of course, is utilizing some of that information at this time.

MR. BARTON: Have you applied any modifications to the shroud?

MR. SWOYER: No, we have not.

MR. BARTON: To the cracking? So, the shroud is as originally installed?

MR. SWOYER: That is correct.

MR. BARTON: Okay.

CHAIR SHACK: You've also done relatively little to the piping in this plant. Right? Compared to most BWRs.

MR. SWOYER: I'm not sure what you --

CHAIR SHACK: The recirculation piping.

MR. SWOYER: Well, originally, we replaced the safe ends and we have also done stress improvement on the recirc piping. We have done stress improvement on all the stainless steel and all the DM welds in the recirc system and other systems.

CHAIR SHACK: Okay. My generic letter -- does the stress improvement in the hydrogen water chemistry get you out of the augmented inspection?

MR. SWOYER: We continue to do augmented inspection, but we have gone to risk-informed and we've -- we've basically complied with VIP 75.

CHAIR SHACK: Okay. That's your two mitigating measures then. Is it the stress improvement and the hydrogen water chemistry.

MR. SWOYER: You are correct. Yes.

CHAIR SHACK: And you've -- what kind of cracking do you have in the recirc piping itself?

MR. SWOYER: We had two instances of cracking in the recirc piping in Unit 1. We had the N1 nozzle, the 26 inch and also one in one of the 12 inch and we weld overlays on those two and we've done PDI inspection on every single weld in Unit 1 that is a -- what we call Category C from Generic Letter 8801 and in Unit 2, we plan on doing the remaining welds this particular outage.

MR. BARTON: Have you done inspection of the top guide in the --

MR. SWOYER: Yes, we have. Yes, we've -- when it is available during the outage and they're looking at the guide tubes, we go in and do a visual inspection on the top guide.

MR. BARTON: Have you found any evidence of cracking?

MR. SWOYER: Not so far, sir.

MR. BARTON: Not so far.

CHAIR SHACK: Now, what's the difference in fluence between the top guide and the core shroud, the H4?

MR. SWOYER: Difference in fluence, well, the top guide has the highest amount of fluence.

CHAIR SHACK: Is it a factor of --

MR. SWOYER: The top guide, we had taken samples of the top guide for the BWR VIP back in 2003 and one of the samples had hit one time sense of 21st. Yes, sir, and that's above what the core shroud is.

CHAIR SHACK: Now, one of these top guides, it's made up of the interlocking pieces or is this a one piece?

MR. SWOYER: No, sir, it's an interlocking piece.

CHAIR SHACK: It's interlocking.

MR. SWOYER: Yes, sir.

MEMBER BONACA: I have a question relating to the LRA. You did refer to the LRA reflected in staffing a few years ago. Reflected in the plant history prior to the power uprate. Okay.

The question I have is that are you going to look at your problems and commitments and how they fit now at the higher power level? For example, the corrosion. You might expect that there will be some impact by the power operators and piping.

How do you deal with that? I mean do you have it reflected already in your LRA commitments or do you have to make an adjustment or --

MR. FLYTE: Bruce, can you speak to what we've -- no, we're done with -- the FAC program is -- done anything for EPU? Have we changed the FAC program?

MEMBER BONACA: Just an example.

MR. FLYTE: Yes, it's a good one to follow. Have we made any specific changes for EPU to the FAC program that you're aware of?

MR. SWOYER: Well, this is Bruce Swoyer.

We have evaluated the effect of EPU on the FAC program. In some cases, there's increases. Other

cases, there has been decreases in the impact on FAC.

MEMBER BONACA: So, what you're telling me we are talking -- for that issue, have you performed a thorough review of programs that you have presented us?

MR. KRAIS: Yes, the programs for license renewal do take into account the extended power uprate and higher power levels. All the evaluations done here, license renewal work done at the EPU conditions. That's one of the things we touched on earlier. Both projects were done within the same group so that they could be integrated.

MEMBER BONACA: Although, I mean your history -- your data is based on operation at a lower level. So, you have to --

MR. KRAIS: That's correct.

MEMBER BONACA: -- assume issues and project.

MR. FLYTE: We do have a additional commitment that we've added to our commitment list to really look at operating experience at extended power operating conditions in the future to -- to see if anything else pops out before we enter the period of extended operation. So, that is kind of a safeguard in that area.

MEMBER BONACA: Okay.

MEMBER ABDEL-KHALIK: Could you tell us about the nature of the OPRM modifications that you were making?

MR. KRAIS: Basically, the OPRM modifications, we upgraded from the original design to a digital NUMAC system from General Electric.

MEMBER ABDEL-KHALIK: What motivated the modification?

MR. D'ANGELO: Obsolescence.

CHAIR SHACK: Okay. It wasn't something you needed for the power uprate?

MR. WILLIAMS: This is Jim Williams. I'm with PPL Susquehanna.

We had to go to digital OPRMs in order to implement ARTS MELLLA. So, that's what precipitated going to the GE NUMAC for OPRMs.

MEMBER ARMIJO: I have a couple of questions on your hydrogen water chemistry. If I recall from the EPU reviews, you intended to increase the amount -- the hydrogen input to be -- to account for the increase in power. Is that correct and are you doing that?

MR. D'ANGELO: Yes.

MEMBER ARMIJO: That is correct. Okay.

The other thing is since you've instituted hydrogen water chemistry, have you found any new cracks in any of your core internals or piping? Not extension of existing cracks, but anything new to be --

MR. SWOYER: This is Bruce Swoyer.

No, we have not. Again, the only real area that we have cracks in as far as internals go are the shroud and we have not found -- to date, we have not found additional crack.

MEMBER ARMIJO: Thank you.

CHAIR SHACK: Now, you don't use the noble metal editions because you have enough shielding in your turbine building that shine doesn't bother you. Is that basically the situation?

MR. PAGODIN: Yes, that's basically correct. We operate at a moderate hydrogen injection rate and, you know, we've analyzed all the radiation levels on the plant both at the pre-EPU conditions and at full EPU conditions. We continue to monitor that and they are all acceptable for continued operation.

MEMBER ARMIJO: You also have electrical chemical potential probes in these plants. Do you monitor that or just the hydrogen input?

MR. PAGODIN: Yes, we have installed those probes several times. We did it again as part of our

EPU project and we will be putting it -- in the future, we've be putting additional probes in. They don't last very long.

MEMBER ARMIJO: Yes, I know that's the problem.

MR. PAGODIN: So, we don't have them in there continuously, but we've put them in at various times throughout the power uprate as well.

MEMBER ARMIJO: Okay. Just spot check as things are --

MR. PAGODIN: That's correct.

MEMBER ARMIJO: Okay.

CHAIR SHACK: Okay. Where are the probes?

MR. WILLIAMS: This is Jim Williams.

The probes are actually contained in the OPRM streams.

CHAIR SHACK: Okay. And what kind of potentials are you reading when they are reading?

MR. WILLIAMS: All right. You're beyond my area of expertise.

MR. SWOYER: This is Bruce Swoyer.

I have seen data from chemistry that we can get -- they have gotten down to minus 500, but we track it. Again, I don't have the data from the chemistry exactly what -- how it tracks through the

vessel, but based in the lower portion of the vessel, they can get down to minus 500.

CHAIR SHACK: But, you can move those things in the stream up and down. Right? No?

MR. PAGODIN: They're fixed. Basically, you've replaced one of our LPRM strings with the probe.

MR. BARTON: A couple of questions on the responses to BWR VIPs. In your response to VIP 38, the shroud support inspection contains action items that you mention that you were -- in this -- in your response here, you mention that the program includes actions planned to inspect welds that are inaccessible. Those always kind of interest me.

The same comment on VIP 41, jet pump assembly inspection and flow evaluation. Again, your response to this is that you're going to do inspections to welds that are presently inaccessible.

So, my question is how do you plan to do your commitments on inaccessible weld inspections?

MR. FLYTE: Bruce has the magic on that I think.

MR. BARTON: I always knew there was somebody that could answer that.

MR. SWOYER: As far as VIP 38, that's for

the shroud supports. There are two welds down there, H9 and H8 and they are inaccessible. The bottom half of those welds, of course, are inaccessible. We have done UT from the outside of the vessel. GE -- using GE GERIS and Southwest Research has also done that to look at the H8 which is on the inside welded to the shroud. So, we have done UT and done full inspection on those welds.

As far as the jet pump welds, that's the thermal sleeve welds and no, we have no inspected those. We are very involved in the BWR VIP and the BWR VIP is attempting to establish a program for that. Either -- I know that there have been inspection groups that have tried to get smaller transducers to get down in there and also the BWR VIP is trying other methods like risk methods to determine how to resolve that problem. But, we will be following the BWR VIP as --

MR. BARTON: You're done the shroud and you're still working the jet pump?

MR. SWOYER: Excuse me, sir.

MR. BARTON: You've done the shroud, but you're still working on the jet pump? A program for that.

MR. SWOYER: That is correct.

MR. BARTON: Thank you.

CHAIR SHACK: Can you get back to that shroud inspection again? Can you put that shroud diagram back up? On whether it's got those --

MR. SWOYER: Yes, there's H9 and H8 at the bottom there. The vessel wall. I should get closer to the mike.

CHAIR SHACK: So, you're inspecting those from the outside?

MR. SWOYER: Outside. Yes, sir.

MR. BARTON: It's interesting

MEMBER SIEBER: You can do it.

MR. SWOYER: Oh, yes, sir.

CHAIR SHACK: How do you qualify that technique?

MR. SWOYER: It is qualified.

CHAIR SHACK: Is it qualified?

MR. SWOYER: Yes, sir.

CHAIR SHACK: An ASME performance demonstration or your own kind of home blue qualification?

MR. SWOYER: It would have to be a BWR VIP. Yes, sir, demonstration.

CHAIR SHACK: Okay.

MEMBER ABDEL-KHALIK: What is the root

cause for the turbine moisture separator vane damage?

MR. KRAIS: The cause of the turbine moisture separate vane damage is basically some spacers in between the various vanes that over a period of time have degraded causing the vanes to either shift one direction or another and that was -- we chose to replace our vanes as opposed to do temporary repairs on those spacers and that could increase performance as well as to repair the damage that we've observed?

MEMBER ABDEL-KHALIK: And what is the nature of the damage?

MR. KRAIS: Erosion and degradation of the spacers between the vanes themselves.

MEMBER SIEBER: Did you replace them with like kind design and materials or did you --

MR. KRAIS: Upgrade materials.

MEMBER SIEBER: Upgrade?

MR. KRAIS: Yes, upgrade design --

MEMBER SIEBER: What's upgrade consist of?

MR. KRAIS: The primary upgrade was in the design of the vanes themselves. Double-pockets versus single-pocket vanes.

MR. FLYTE: In summary for our presentation, I would just like to say that our

license renewal team has prepared a license renewal application that conforms to the regulatory requirements, the extensive use of established industry guidance and we had a team that was actively involved with industry activities and the bottom line for us is that Susquehanna is ready to and will manage aging in the period extended operation.

MEMBER STETKAR: I'd like to -- you know, the penalty you pay for getting through your presentation really fast is that we have time.

I'd love to follow up on -- on us -- I'm sitting here trying to think in real time. The question I asked initially and I wanted -- I didn't want to spend too much time on it so that everybody could get through the other issues that might have been more -- of more interest, but the turbine building scoping regarding those HPCI cables that I asked about, unfortunately, the only information that I have is a paragraph in the inspection report that makes a reference to the engineering evaluation you performed and it didn't identify the function of the cable. So, I know now they're related to transfer from -- you normally take a section from the condensate storage tank, right, on HPCI?

You said that you -- if I made my notes

correct here, you did -- you concluded that, if I understand it, the -- you did -- the only impact on those cables would be from a high-energy line break, but that those cables are not required for those particular high-energy line break events. Is that my correct understanding of the conclusions?

And if I'm not correct, I need to get my understanding corrected.

MR. FLYTE: Yes, that's correct. That's my understanding as well. So, I -- Jim, can you offer any --

MEMBER STETKAR: High energy -- because HPCI is kind of important for high-pressure makeup and if you have a high-energy line break in the turbine building, it's quite like you're going to lose feedwater condensate or something like that which HPCI tends to be relatively important for. So, I'm kind of curious about that rationale.

MR. WILLIAMS: Yes, this is James Williams again.

The conduit and cabling that you're talking about is the HPCI CST suction swapover from the CST to the suppression pool.

MEMBER STETKAR: Right.

MR. WILLIAMS: The analyses that they

performed, the high-energy line break is the situation that would affect this conduit and cabling and a high-energy break line in the turbine building is not going to affect those cables to achieve safe shutdown following a high-energy line break.

We would lose feedwater in that case, but HPCI would still be available. HPCI and RCIC.

MEMBER STETKAR: Until CST is drained. At which point, you have to swapover for long-term cooling to -- unless you somehow cool down and depressurize and --

MR. WILLIAMS: That's correct. It still can be performed manually.

MEMBER STETKAR: These are things like level-sensing cables or is --

MR. WILLIAMS: Yes, it's a low CST level-sensing cable.

MEMBER STETKAR: Okay.

MR. WILLIAMS: There's 135,000 gallons reserved in the CST for HPCI operation.

MEMBER STETKAR: Yes, that's fine, but eventually, you run out of water.

MR. WILLIAMS: Um-hum. But, at that time, our emergency operating procedures required us on the high-suppression pool level which -- what would

happen, you'd take a suction of CST water. It would eventually raise the level in the suppression pool.

MEMBER STETKAR: Right.

MR. WILLIAMS: And our emergency operating procedures require us to transfer over to the suppression pool.

MEMBER STETKAR: And you still do that manually?

MR. WILLIAMS: Correct.

MEMBER STETKAR: Do these cables if they're the level-sensing cables also provide level indication CST in the main control room?

MR. WILLIAMS: Not those particular cables. These particular cables are strictly the level switches. It's not the level indication. We still have zero to 100 percent level indication.

MEMBER STETKAR: And you mentioned this is only in Unit 2 turbine building?

MR. WILLIAMS: That is correct.

MEMBER STETKAR: It's --

MR. WILLIAMS: Only in the 2.

MEMBER STETKAR: So, it only affects Unit 2?

MR. WILLIAMS: Correct.

MEMBER STETKAR: The cables are routed

differently in Unit 1.

MR. WILLIAMS: Correct.

MR. PAGODIN: Phil, do you have something?

MR. BRADY: Yes, I can -- again, this is Phil Brady.

The cables we're talking about on the Unit 2 side is because of the CST location the cable routing does through. It's down in the basement of the turbine building and it's very short, the area where it comes out of the location of the CST and then goes into our reactor building. So, it's a very short distance. It's down in the lower elevation of the turbine building not near a lot of our high-energy lines that are in the turbine building location-wise. So, part of that analysis included the location analysis to assure that the high-energy line break was, in fact, not going to be an impact. Okay.

On the Unit 2 side, the reason that's not an issue is the cables actually come out of the CST area on the Unit 1, go through our diesel generator which are safety related and then use the manhole system in front of the diesel generator building as the route back into the building. So, it avoids this route into the turbine building on Unit 1 side because of the location of the diesel generators and safety-

related routing.

MEMBER STETKAR: Okay. Thanks. At least, I understand a little bit better.

MEMBER SIEBER: Are these your duct lines or are they in trays or duct line?

MR. BRADY: No, it's all in conduit. These particular ones are routed strictly in conduit.

CHAIR SHACK: As John said, we seemed to be ahead of schedule.

MR. BARTON: I got a question. You have several tanks onsite whose bottoms rest on oil-sand pads. Now, what's your inspection program for these bottoms? I know some of these tanks with oil-sand pads do fail.

MR. FLYTE: Mitch, can you address that question?

MR. MCFARLAND: Yes. This is Mitch McFarland with the Washington Oil Team.

The inspection is the condensate storage and refueling water tank inspection which is a one-time inspection that will perform UTs on the bottoms of the tanks.

MR. BARTON: Have you done an inspection yet?

MR. MCFARLAND: No.

MEMBER SIEBER: They're carbon steel tanks? Carbon steel.

MR. MCFARLAND: I believe they are. Yes.

MEMBER BONACA: Since I have -- have a little time, I wanted to ask a question. With inaccessible locations, you know, the inspections are relying on BWR or VIP program. It would be a big problem to discover that they really haven't got a solution yet. So, you know, who have been in license renewal for a long time as we have been, we're still waiting to see when a solution will come and this will be over the 60 years of the plant or after that and if you don't, for those progress that is being made.

MR. FLYTE: Bruce is going to take a shot at that, but I don't think we have much of a --

MR. SWOYER: Yes, Bruce Swoyer. Yes, I am a representative for Susquehanna on the BWR VIP Assessment Committee.

And, you know, the Assessment Committee and the BWR VIP is trying to be very proactive and resolve these issues. These aren't issues that we take lightly. So, the industry since Susquehanna is not alone, for example, like on the jet pump thermal sleeve lack of inspection, inaccessibility, all the -- most all of the BWRs are in that realm. So,

therefore, it behooves us to try and resolve that problem as soon as possible. So, I know for a fact we are working on that at this time.

MEMBER BONACA: But, you don't have any sense of when?

MR. SWOYER: No, sir.

MEMBER BONACA: It is --

MR. SWOYER: I mean it's being worked on. All I can tell you is we've had some success. We had -- we have inaccessible inspection areas in the core spray system for the BWR and the BWR VIP has just issued an NRC-approved resolution to that based on risk. So, that is -- at least, that is a success and we hopefully may be following on that path for some of the other areas that are inaccessible.

MEMBER BONACA: Thank you.

MR. SWOYER: You're welcome.

MEMBER ABDEL-KHALIK: Have the data from the steam dryer instrumentation already been compared against the model predictions for the first step?

MR. KRAIS: That is correct. We have done that comparison and it has been submitted per our EPU license conditions to --

MEMBER ABDEL-KHALIK: And how does that comparison looked?

MR. KRAIS: The comparison shows that the assumptions made in the licensing for EPU was conservative compared to the actual data that we saw. So, our under-prediction factor in the licensing basis is slightly higher than what it was actually after the data comparisons were completed. Which means our licensing basis was conservative.

CHAIR SHACK: Any other questions? Well, I think we're on break until 10:35 since we don't want to get ahead of schedule.

MR. BARTON: Thank you, Mr. Chairman.

(Whereupon, at 9:41 a.m., off the record until 10:33 a.m.)

CHAIR SHACK: We can come back into session. I think Brian Holian will introduce the staff presentation.

MR. HOLIAN: Well, good. Thank you. Introducing the staff presentation, I just had a couple of other comments.

Two additional introductions, one joining us at the side table here is Dr. Sam Li, the Deputy Director for License Renewal. Wanted to recognize him and also at the front table assisting Evelyn a little bit with slides and also in the staff presentation some or in questions is Senior Project Manager for

TMI, who you'll hear from this afternoon, Jay Robinson. So, he's up helping also.

I had one comment from this morning's presentation by the licensee and it affected our staff review a little bit and that was the issue of the power uprate being done kind of in parallel with or at least partially in parallel with the license renewal application.

In general, the NRC frowns on, you know, two significant licensing actions like that coming in at the same time for the potential that, you know, the licensing basis, one, be confused and the SER write-ups for the two-year period where we're writing up an SER and even the applications themselves, the licensee either putting it -- the power uprate assumptions in license renewal or not in.

So, plants have approached us before. We've told them, you know, we don't say it's impossible, but we frown against it just to make sure that, you know, the reviews can go on and that one review even the timing of that is not dependent on the other one.

So, I do appreciate the committee's comments and questions on that and making sure that, you know, one, especially the operating experience

they have for the extended power uprate is reflected in the license renewal application and that was an item that the staff recognized.

We actually did work with the licensee and put, as they mentioned, their license renewal application on hold for several months and the staff -- the technical staff concentrated on the extended power uprate.

I mention that for a couple of reasons. One, it worked out well in Susquehanna's case and it's also something the committee will see again. I know Crystal River's in for an application right now for both and the industry, themselves, have learned a little bit from that on staging it so that they can clearly put the assumptions in for power uprate into the license renewal application. So, I just wanted to highlight that.

With that, I'll turn it over to Evelyn Gettys.

MS. GETTYS: Good morning. My name is Evelyn Gettys and I'm the Safety Project Manager for the Susquehanna Electric Station Units 1 and 2, the license renewal application.

I will begin by providing an overview of the LRA and the staff's view. We will discuss section

1 of the SER. Glenn Meyer will discuss the license renewal inspection and the finding and then we will discuss the staff's review of section 3 and 4.

The license renewal application was submitted by letter dated September the 13th, 2006. Both units are BWRs with a Mark II containment. Both the extended power uprate and the license renewal application were submitted to the NRC around the same time. The LRA considered the EPU power level.

The operating license expires in the year 2002, excuse me, 2022 and 2024 for the respective units.

The plant is located near the town of Berwick, Pennsylvania.

The staff issued the SER with open items in March 2009. The staff issued 278 RAIs. The applicant has 59 commitments.

CHAIR SHACK: Isn't their commitment 60?

MS. GETTYS: Yes, that's true. It's 60, but as I'll explain later, one was removed.

CHAIR SHACK: Oh.

MS. GETTYS: The slide shows the schedules for the audits and the regional inspections that occurred during the review.

As a result of the staff's review,

additional piping was brought into scope according to (a)(2). Therefore, the applicant amended the LRA to include portions of non-safety related piping attached to safety related system structures and components located within containment and non-safety related piping attached to safety-related systems, structures and components at the containment penetration and extending outside of the containment in accordance with 10 CFR 54.4(a).

Based on the review of the LRA and additional information submitted as a result of the request for additional information, the staff concluded that the applicant's methodology is consistent with the requirements.

The staff did not find any omissions of systems or structures in the scope of license renewal in accordance with 10 CFR 54.4.

In section 2.3 of the SER which documents the staff's review of the scoping and screening results of the mechanical systems, the staff concluded that based on its review of the LRA and additional information submitted as a result of the RAIs, that there were no omissions of the structures or structures components from the scope of license renewal in accordance with 10 CFR 54.4(a) and no

omissions from the Aging Management Review in accordance to 10 CFR 54.21(a)(1).

In section 2.4 of the SER which documents that staff's review of the scoping and screening results for structures, the staff concluded that based on its review that there were no omissions of the structures or structure components for this license renewal in accordance to the regulations.

Section 2.5, the electrical system, as a result of the staff's review, the applicant added sections of the offsite switchyard to the scope of license renewal for the station blackout in accordance to 10 CFR 54.4(a)(3).

With the inclusion of the sections of the offsite switchyard and based on the review of the LRA and additional information submitted as a result of the RAIs, the staff concluded that there were no omissions of electrical and instrumentations and control system components from the scope of license renewal and no omissions from the AMRs in accordance with the regulations.

Overall for section 2 of the SER, the staff concluded that the applicant's scoping and screening methodologies is consistent with the requirements of the regulations and that --

CHAIR SHACK: Let me interrupt for a second. Has the staff gone back and looked at the earlier license renewals in terms of the SBO? Have you changed the rules in the middle of the game here? Did somebody get through?

MS. GETTYS: Yes.

MR. HOLIAN: Yes, the -- in general, the -- and we've covered this at a couple ACRS meetings. We put out a revised Draft Regulatory Issue Summary that clarified the wording the station blackout issue that we had. The guidance we had originally.

The guidance originally said typically you would go out to the switchyard breakers. That was the previous guidance.

It was put out last year, a Draft RIS to define that a little bit better because of some of the plants were coming up with issues and gee, that's not typical for us and making those arguments and our electrical branch in particular as they review the station blackout rule felt it important that you get out to the switchyard and station voltage as they deemed it.

As I discussed really at Indian Point which we covered last month, they had an open item on this issue and our latest guidance is still to look at

that revised RIS and it's most probable that the staff has extended our interpretation of the station blackout rule and getting the station voltage further that we should have. So, we'll probably go back to the RIS that's out there currently which is typically get to there, but a licensee can define what's in their current licensing basis and, you know, how they can cope with the station blackout.

CHAIR SHACK: But, I mean specifically except for Calvert Cliffs, have you gone back and --

MR. HOLIAN: Yes, we've gone back. The electrical branch has gone back on -- out of the 51 plants, about 40 of them get out to the switchyard breaker. So, we've looked at that and a few plants in there and during the review process did not. They had reasons why. The staff right now is still looking at whether it's worthwhile to go back.

If we were to go back on those, it would probably be through the backfit provisions unless they voluntarily decided to scope into the switchyard breakers.

MEMBER STETKAR: Brian, since --

MR. HOLIAN: Yes.

MEMBER STETKAR: -- Bill brought it up and on Indian Point there was a discussion about

transmission voltage versus not. I noticed on Susquehanna that they've taken one of the paths out to the low side transformer breaker which is not "transmission system" voltage, but that's -- just to keep --

MR. HOLIAN: Right.

MEMBER STETKAR: -- the target, that's okay now.

MR. HOLIAN: That's okay now.

MEMBER STETKAR: Okay.

MR. HOLIAN: That's right. That's okay now.

MEMBER STETKAR: Just -- just to keep the target --

MR. HOLIAN: The target would be -- that would meet the current RIS that is out there.

MEMBER STETKAR: Okay. And certainly circuit breakers.

MR. HOLIAN: That's right and it meets their licensing basis that they were licensed for. That's right. Which in some ways the industry, you know, told us that by an NEI letter about a year ago. Staff, you're basically trying to extend, you know, the boundary for a few plants.

For most plants, I think it wasn't an

issue because either their licensing basis had it in there to the switchyard which is not always clear. But, it either had it in there or it was an easy item for most plants. Hey, we'll go there. There have been some failures of some of the components of the phases and some of the switchyard breakers. So, even the plants themselves under the maintenance rule will have that scoped in and it's not an issue.

So, that's while you'll still see some plants here coming through and --

MEMBER STETKAR: The question is it a breaker or a disconnect, you know. I think we're settled on an active breaker and this one, you know, then it doesn't need to be transmission voltage whatever that is or low-side breakers. Okay.

MR. HOLIAN: That's right. That's right.

MEMBER STETKAR: Okay.

MS. GETTYS: Thank you. Overall for section 2 of the SER, the staff concluded that the applicant's scoping and screening methodology was consistent with the requirements of the regulations and that there was no omissions from the scope and screening review in accordance with 10 CFR 54(a) and there were no omissions from the aging management review in accordance to 10 CFR 54.

This is really bothering me. This feedback. Sorry. Better.

I'm now going to turn it over to Glenn Meyer.

MEMBER STETKAR: Evelyn, let me ask you one question before Glenn comes up. I've had too much time to think on the break.

Back to my HPCI cables. It's a scoping and screening, you know, 54(a) tool or whatever it is. One, and this is mostly for my education, when the applicant and you consider whether or not something is potentially in scope, is there some consideration of failure modes and effects?

For example, if I cut a cable, I cannot transmit electricity through it and that's one failure mode. If I short the cable, I might get a spurious signal. So, for example, are those two failure modes considered when you think about possible affects from interactions?

MS. GETTYS: That's a good --

MEMBER STETKAR: So, for example, these cables, if they're level-sensing cables, could a shortcircuit -- could some sort of interaction cause a shortcircuit to the -- closes the CST suction valve? Which, for example, if suppression pool level was

normal, would cavitate the HPCI pump which is not a good thing to do.

Do you think to that level of detail and is the applicant suppose to do that? I don't know if these particular cables can do that, but I'm trying to get in my own mind the types of thought process that goes into determining whether something is in scope or out of scope especially with the -- you know, the non-safety versus safety interactions.

MEMBER BONACA: -- is an element.

MR. ROGERS: Yes, I'm Bill Rogers. I'm from the Division of License Renewal.

And the way the rule is set up, it's set up such that for non-safety related components if they can affect the (i), (ii), (iii) of (a)(1) which brings safety related components in the scope, if they can affect any of those three things, that would bring it -- the non-safety related features in the scope regardless of the failure mechanism. That's the conceptual approach.

CHAIR SHACK: But, you would consider all the failure modes that could occur in making that decision.

MR. ROGERS: Yes. Yes.

MEMBER STETKAR: Both failure to perform

or spurious-type.

MR. ROGERS: Yes, so for (a)(2) in general, a non-safety related structure or component can be brought in the scope if its failure to function can affect one of those, the three portions of (a)(1) or if it could have a physical impact on a safety related structure or component and cause its failure.

MEMBER STETKAR: Um-hum.

MR. ROGERS: So, yes, the applicant is to consider all the failure effects and that, of course, is -- that is known effects not hypothetical effects.

MEMBER STETKAR: No. No. No, but --

MR. MEYER: From the regional -- the inspection standpoint, I would say that approach is pretty conservative. What we typically see is a spaces approach. They referred to that. So, it doesn't get to the level of failures and -- but, if it's performing some function and it is in that space, that building, that room, that whatever, that -- all the equipment in that room, building, space is in scope. This is one example where they did choose to go beyond that and do the evaluation and see was the function preserved and so --

MEMBER STETKAR: And that's why --

MR. MEYER: Right.

MEMBER STETKAR: -- I brought it up. Because the function that they looked at is failure to transfer when required. I didn't hear and I don't know if those cables, I'll probably ask the applicant here in a moment, but I was trying to get straight in my mind whether they should also consider the fact that those cables could spuriously close a valve when they're not suppose to and because they did transit past the just impact or no impact and make an argument based on a particular function and a particular response scenario and take credit for manual operator actions, they've gone past as you said most -- what most people do.

MR. MEYER: Right. No, and in HPCI, I think the system is typically interlocked. So, that it insists that one valve is open. If you had, I guess, for example, sure if that would tend to close one of the suction valves, it would automatically open the other. But, the controls prevent a simultaneous suction valve closure. But, those are the details that the analysis -- you would expect to have I mean.

MEMBER STETKAR: I think if -- we okay on time? I don't want to go forever, but if I could ask the applicant then, can failures of those level-sensing valves cause a spurious signal to close the

normal condensate suction valve?

And basically, the, you know, spurious low level on the condensate storage tank is what I'm talking about because that would -- that would --

MR. BRADY: Yes, this is Phil Brady.

That circuitry is set up in such a way that if, in fact, the cable were to fail and, in fact, cause the valve to close from the CST, a loss of suction would be initiated in either trip HPCI off at that point or initiate the transfer operation to the suppression cooling. But, those cables themselves have been evaluated from a failure mode in each direction. Both a short, short to ground, open.

MEMBER STETKAR: Okay. Thanks. Thank you. Good.

MR. MEYER: Okay. We're ready. Okay. Good morning, Chairman Shack and ACS members. I'm Glenn Meyer. I lead the regional license renewal inspection. I'd like to briefly cover our results.

The inspection basically endeavors week two objectives. We do look at scoping of non-safety system, structures and components. We also look at aging management programs to evaluate their soundness. In this case, we looked at 12 new aging programs and 17 existing programs.

We do use a third technique of a system review to look at the two objectives. We pick the HPCI system and so, we look at the condition of the system, the test records, take a look at the complements that are in the field to make sure that aging management programs that have been, you know, put in place will cover all the components and also get a sense of how well they're addressing the aging that's occurred thus far.

MEMBER ABDEL-KHALIK: Is there any history of problems with the HPCI system at --

MR. MEYER: No, what comes into play is that HPCIs can be -- because it's somewhat self-contained. Many of the systems go throughout so much of the plant that it really wouldn't be feasible to pick that system and look at test records, conditions and the aging programs that apply. So, we tend to pick -- it's not because HPCI has been a problem and it deserves the focus. But, it suits our purposes well would be one of the main reasons. So.

MEMBER ABDEL-KHALIK: Would you tend to select generally an MSPI system or this just happens to be a convenient one?

MR. MEYER: Yes. Yes, MSPI, the mitigation system performance index. I would tend to

say yes on PWRs. Sometimes we'll look at aux feedwater. Again, self-contained safety-related non-safety -- since we're looking at scoping of non-safety components, we got to look at what's in the vicinity. Is there, you know, another drain line or demon water or something that could affect the system? So, it's a check on that.

But, yes, we tend to pick, you know, systems that matter that would tend to be in the MSPI.

MEMBER ABDEL-KHALIK: Has the indication for HPCI at Susquehanna been consistently green?

MR. MEYER: I can't talk to the history of HPCI at Susquehanna.

MR. BARTON: But, you don't always pick HPCI or aux feedwater. Do you?

MR. MEYER: No, sometimes we've picked a river, you know, cooling systems. There's been a variation.

MR. BARTON: Right. I just wonder if people know where you are beforehand. That's all. I want to make sure that they don't know what system you're going to look at in BWR and a PWR. That's the only reason.

MR. MEYER: Yes, and the nature of our review is, you know, if they know in advance, I don't

think it compromises our review.

MEMBER ABDEL-KHALIK: Does the applicant have an answer to the historical status of the HPCI system?

MR. FILCHNER: Yes, this is Duane Filchner, Regulatory Affairs.

The HPCI system from an MSPI standpoint has been green since MSPI was initiated.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. MEYER: There were a few scoping related items that we picked up during the aging management review and I'll talk to those.

In general, we felt that scoping of non-safety system, structures and component was generally accurate and that they had used an acceptable approach. As part of that, we did look at structural and spatial interactions.

Regarding the HPCI cable issue that we talked to, what the inspection found was that they had identified -- an engineer had identified there was a safety-related cable that hadn't been fully evaluated and they had put it into the corrective action program.

The inspection concern was that they hadn't updated their application to indicate that.

So, they did amend the application to do that. I would say that the inspection report says it's in Unit 1, but it's, in fact, in Unit 2. So, you know, the Unit 2 is correct and it did go out and look at the cable and they are in conduit. They are in the vicinity of the feed pumps. So, it's appropriate to consider for a high-energy line break and so --

MEMBER STETKAR: Is -- if I can interrupt for a moment, maybe I completely misinterpreted. The problem is we don't get -- we don't have benefit of the updates to the license renewal application or at least not immediately. We have a 2006 version. We don't have all of the supplements.

Are the -- well, in principle, we do. In practice, I don't --

MR. MEYER: Okay.

MEMBER STETKAR: -- right at the moment. Is now that area of the turbine building included in scope for 54.4(a)(2)? For those --

MR. MEYER: No.

MEMBER STETKAR: Okay. So --

MR. MEYER: No, based on their evaluation.

MEMBER STETKAR: So, I --

MR. MEYER: They were able to say that --

MEMBER STETKAR: Okay. Fine.

MR. MEYER: -- the turbine building did not need to be in scope.

MEMBER STETKAR: Thanks. Sorry.

MR. MEYER: Okay. The aging management programs, I'll briefly describe some of the issues that we followed.

The first one was in the supplemental pipe and tank inspection program. Our inspectors found that the starting air tanks for the emergency diesel generators and some of the stainless steel fuel oil components had not been put into the program and the LRA was amended to include those.

The buried piping and tanks inspection program, we felt that their sampling for coded -- coded pipes had not been as thorough as it should have been and also the way that they controlled opportunistic inspections, in other words, digging up a buried pipe for other reasons, but yet doing a thorough inspection so that it was taken credit for and documented and they amended the LRA to address those issues.

They also had the area-based NSAS as in non-safety effects safety inspection program and in that they had sampling for the cracking of copper alloy piping, but they had a specification that would

have allowed them to exclude the inspection if ammonia was determined to be absent and we felt that that was -- you know, given that aging is such a long process, that a test for ammonia was an inappropriate exclusion and they agreed to take that out and the application amended.

In the chemistry program effectiveness inspection, the home addressed the qualification of inspectors and they did amend the application to specify ASME coded qualifications.

And lastly, in the programs, the small-bore Class 1 piping inspection program. The program had referenced vibrational fatigue failures, a non-aging effect and subsequently, they did amend the application to delete that reference.

In the existing program that we pursued, the structures monitoring program, we found that it had been a sufficient program for the maintenance role, but that for aging management, we found that it didn't have some of the basic elements it should have in terms of acceptance criteria, inspection record retention, trending of results and inspector qualifications and they did agree that they would upgrade the program in those aspects and amended the LRA to address that.

In the masonry wall program, our inspector as part of walking down the ESSW pump house determined there was a masonry wall there that had not been in the application. It had been a relatively recent modification to address security concerns and so, it hadn't been picked up. So, they amended the application to include that masonry wall.

In the fuel oil chemistry program, I think we made mention this morning about ultrasonic tests that they hadn't met the guidance of the GALL. So, that amended the application to do some UTs of tank bottoms and to take an exception.

There was a question this morning about the recent visual inspections and I checked our inspection record. We had looked at the most recent ten-year inspections and on the delta tank, that occurred in July 3rd of last year and on the alpha tank, it was in August 21st of the year prior. So, it is something that we tend to look at.

Piping corrosion program, the application had not addressed coatings which the aging management program had taken credit for and it also wasn't specific on opportunistic inspections and so, they amended the LRA to address that.

Fire water program, our inspector noted

that in the fire water piping there are some parts that area infrequently wetted for testing and then drained, but they had no sampling of that. Also, many inspections of some piping we felt wasn't properly addressed. So, they amended the LRA to address sampling of such piping.

Instrument air monitoring, the application did not have an aging management program for instrument air. Now, they count on the quality of the air in terms of evaluating aging for components that are -- use instrument air and we felt that it was appropriate that there be some evaluation of how well that was performing if they're going to take credit for it and they amended the application to include commitment 58 to continue existing air quality monitoring.

System walkdown program, our inspectors noted that at the interface between buried piping and the exposed piping inside the building Susquehanna had noted in some instances they had groundwater intrusion and some corrosion at the interface. The issue in our mind was the coating that protects the pipe, it's not clear how far it comes into that building wall and given some evidence of corrosion, we were curious as to how it was going to be addressed and so, they

determined that the system walkdown program was the best on to do that. They agreed they would do some UT inspections of the joint to evaluate the piping and also, as noted, we did find some pipe vaults that hadn't been inspected. They did look at the one. We came back and looked at that and that was acceptable. So, they'll do subsequent reviews of such vaults in the future.

Closed cooling water chemistry, their application didn't address the fact that they had plans to do one round of inspections of components addressed by closed cooling water systems versus the GALL recommended periodic monitoring. So, they amended the application to properly address that.

CHAIR SHACK: On the piping corrosion, there was some discussion of whether they needed coatings or whether cast iron or ductile iron without coatings. Was that an adequate treatment? Was that resolved?

MR. MEYER: I think from the inspection, it wasn't necessarily what was acceptable, what should be coated, but how the program addressed those two types.

CHAIR SHACK: Okay.

MR. MEYER: The HPCI/RCIC turbine casing

program, we felt that the program had insufficient details. I mean they have been doing periodic maintenance and inspection, but the program itself needed some basics on the inspections, the qualifications, the acceptance criteria. They did change that in the LRA.

Lastly, the leak chase channel monitoring program which, you know, addresses the spent fuel pool and the cask shipping pool and looks to see what's in the chases, we felt that the needed some clarification regarding water chemistry and that was done in the application. So.

MEMBER STETKAR: Glenn, you do an audit of the AMPs. Right? What fraction of all of the AMPs did you actually look at?

MR. MEYER: I --

MEMBER STETKAR: Do you have a rough --

MR. MEYER: We typically are in the range of -- we almost always do more than half. So, it's typically a half to three-quarters of the programs.

MEMBER STETKAR: Okay.

MR. MEYER: And simply based on the fact that a lot of the existing programs are part of an ongoing inspections. So, we get a look.

MEMBER STETKAR: The only reason I ask

that is that frankly this -- you guys do a really good job by the way.

MR. MEYER: Thank you.

MEMBER STETKAR: I really appreciate the effort that you put into these inspections.

This report in particular seemed to highlight a much larger fraction of AMPs where you identified a deficiency and I mean a substantive deficiency not a --

MR. MEYER: Um-hum.

MEMBER STETKAR: -- different code case and the applicant came back and basically agreed and amended the program, amended the LRA.

MR. MEYER: Um-hum.

MEMBER STETKAR: The reason I ask about the fraction that you actually looked at is because that list that you just went through is relatively long. Do you feel that there may be additional AMPs out there that you didn't audit that would have similar deficiencies that might merit a little more deep -- another audit?

It's kind of a leading question. It's just that the length of this list and the applicant's kind of agreement with yes, things that you found that indeed were deficiencies. They were added to the

program. Standard words. Was just quite a bit more than at least I've been used to seeing in their reports.

MR. MEYER: Well, like I said, I can't predict the unknown or --

MEMBER STETKAR: Right.

MR. MEYER: -- what were in the other programs, but like I say, we tend to sample and you tend to skip over programs that have been existing, are part of the program. So, a lot of -- you know, ISI program, we don't look at.

Also, in this case, experience does matter and so --

MEMBER STETKAR: Okay.

MR. MEYER: -- we have done a number of inspections over the last two years and, you know, you learn from it and briefly, one of the inspectors had been a resident inspector at Susquehanna and, you know, he was familiar. So, those sorts of things matter.

MEMBER STETKAR: Okay. I'm glad you said that. So, it's -- this is not necessarily a purely random sample?

MR. MEYER: True.

MEMBER STETKAR: Okay.

MR. MEYER: Also, I'll be here this afternoon talking about TMI and the list is considerably shorter.

MEMBER STETKAR: That's right.

MR. MEYER: And you know and still had it's inspectors. It's just -- so.

MEMBER STETKAR: Okay. Thanks.

MEMBER BONACA: Could you comment on the physical conditions of the plant?

MR. MEYER: It's not something we typically do since it's inherently subjective. But, I would give you the one measure that is fairly consistent is the structural or concrete area. The same inspector is very experienced and he does that each and every plant and, for example, at Susquehanna, he said that the condition of the structures was very good. That, you know, the aging effects are minimal and that he thought that, you know, the buildings themselves were in very good shape.

You know, the overall material condition is not something that we try and address. I mean it is addressed to a large extent by the maintenance rule and the MSPI indicator, but I think it was -- well, like I said, structurally, the plant's in very good shape.

MR. BARTON: I noticed you addressed structurally in one report. It was either the audit report or this. I don't remember. I don't remember, but in neither report did it address the overall material condition and I think that's important because it tends to tell you what's the culture at the site, you know. The system's rusty. They got leaks or whatever or the system is well maintained and you know and you guys know your own plants. You got residents and I think you know how to assess, you know, the material condition. I mean is it -- normally, you used to put words in there like it was adequate. In the last few plants I reviewed, it's not been addressed at all. So, it makes me wonder why wasn't it addressed. Because it's not adequate this time or they didn't look at it or didn't assess it. Whatever. But, I think it's important to know from the regulator's position, you know, how do you feel the overall condition of this plant is, you know, and I'm surprised it doesn't get mentioned.

MR. MEYER: All right. Well, I would say that we certainly try and meet our customer's need and that would be the headquarters staff and if they wanted that, we certainly could do it. My belief is that it is subjective.

MR. BARTON: Sure.

MR. MEYER: Too many times it tends to become a measure of housekeeping. I think the MSPI that looks at, you know, the availability and reliability of systems is probably a better measure of overall condition of the materiel. So.

MEMBER BONACA: Yes, but for example, the containment that -- the drywell. You know, it's part -- it's still -- I believe it's still an ISG for BWRS and, you know, I would have liked to see some look at it or inspections, conclusions why it is not discussed by the applicant nor by the presentation here.

MR. MEYER: Okay. Our inspection looks at the records of, you know, all the various ASME inspections that they have.

To go on the inside and look at the liner, would merit going during the outage and it's not something we typically do unless we see indication that there are problems that merit that. Again --

MEMBER BONACA: And I would have liked to hear that because it had indication or et cetera --

MR. MEYER: Okay.

MEMBER BONACA: -- you know, the rest. Because I mean it is the only substantial ISG that you have for BWRs. So.

MR. MEYER: It's a good note and certainly we -- if we choose not to return during an outage and look at the inside, then we'll make that clear.

MEMBER BONACA: All right. Thank you.

MEMBER BROWN: Can I interject for a minute. I'd springboard off of John's comment.

Well, I've known Glenn from many years ago in the Naval Nuclear Program and you talk about the subjectivity of the plant. Put aside the concrete looks good, but the subjective maintenance, appearance of the plant and the Naval Nuclear Program, I mean we walk into a submarine and we see rusty pipes, dripping water, CO gets fired. I mean I'm being pejorative. You know, there's always some gray line, but we use the subjectivity with the thought process that if you're not taking care of vacuuming the rugs and wiping the dust off of stuff or whatever it is, you may not be paying attention as much to the PMs that need to be done, the recording of information. You know, how careful are you with your tripping calc procedures and others? So, whether that's good or bad, whether it's right or wrong, it's just the way it's used.

MR. BARTON: But, to me, I always use it. It's a culture -- it's a culture just like --

MEMBER BROWN: You walk in. You got rust and water and steam leaks and everything else. You're going to say um, geez, that's --

MR. BARTON: That may run good, but it's falling apart.

MEMBER BROWN: Yes.

MR. BARTON: I mean it's --

MEMBER BROWN: Well, and that's probably wrong. Maybe, I guess.

MR. BARTON: Maybe. Yes.

MEMBER BROWN: I'm just -- you know, it just -- I tend to agree with him that a little bit of subjectivity as long as you -- is not all that bad. So, I'll stop right there. I just --

MR. MEYER: Well, I will say I don't want to diminish value of an experienced inspector's ability to go various places and draw conclusions based on what that inspector sees. So, there's value in it, but it's also fraught with some risk of the subjectivity and how do you draw an overall conclusion for the plant.

We used to try to do that in the days when we had SALP, the Systematic Analysis of -- yes. Yes, and it didn't tend to be that useful.

MEMBER ARMIJO: It was terrible.

MR. MEYER: Another thing worth mentioning is --

MEMBER BROWN: See I take advice from somebody who's --

MR. MEYER: A thing worth mentioning is we do have resident inspectors. Everyday they're inspecting. They're in the plant. If it's a leak, yes, I totally agree. A leak is a valid indication of a problem and they would ensure that it's been in the -- it's been put into the corrective action system or it is subsequently to address the problems.

So, all the specific problems get addressed, but an overall materiel condition is something like I -- well, I've said what I believe.

So, was there anything that --

MEMBER BROWN: I'm not going to say another else.

MR. MEYER: -- headquarters wants us to do?

MEMBER BROWN: An observation. That's all.

MR. MEYER: And serve their needs.

MR. BARTON: I would like to add onto Mario's comment on containment. I know you can't schedule your inspection when there's an outage, but

I know the plants that I was at whenever there's an outage, the resident usually went in and did a walkdown of my containment. So, you know, what does he say about condition in containment? Maybe you didn't cover it, but the resident should know and, you know, it could be in your report. You know, containment was, you know, fine or there's paint peeling all over the liner, the liner's rusted. I mean in some of the submittals of other units, you see that comment and I know the inspectors weren't necessarily there. Your team wasn't necessarily there during an outage, but I know it's probably feedback from the resident. So, and you could cover it that way. So, I know you don't have to be there.

MEMBER SIEBER: Inspections have to have attributes and observations as opposed to the place is a dirty place and INPO can easily say this is a dirty place and make it stick.

On the other hand, an inspector going into a plant who notes housekeeping is poor, that puts him on the alert to make sure that he inspects the attributes thoroughly enough to determine what the condition of the equipment is.

I think based on my experience with the Regions that happens.

Maybe you can tell me whether it does or to what extent, but if an inspector goes into a plant that doesn't look very good, that inspector's on the alert as soon as he gets there.

MR. HOLIAN: This is Brian Holian, Division Director of License Renewals and previously nine years in Region I as a manager.

I'd just like to comment on the issue in front of us. I will look back at some of our inspection reports and even in our prep for these sessions, we do bring up material condition and we are looking at how well it's documented in license renewal inspections or just for this subcommittee for a feeling of the condition of the plant. We do agree that it's an indicator. It might not be an indicator we measure, but it's clearly an indicator for the inspectors. We do look at INPO reports. We do look at the reviews of different inspections, maintenance rule, ISI inspections. We are in there every outage. Regional managers, in particular since Davis-Besse, but even before that, are crawling around during the outages every chance we can get. So, those observations are done.

There's probably a better way we can summarize some of that for the ACRS in a license

renewal context for how it influence our inspection samples and other things. I'll take that.

MEMBER BONACA: Particularly on the drywell. As you know, it has been the focus of other review of BWRs in the past two/three years.

It's central to the ISG. I mean it's the main ISG issue.

I was startled not to find any element of a presentation here. I'm pleased to hear that it's in good shape, but, you know, thinking about what the members may like to hear in presentation, that would be probably items that I certainly would like to hear about.

MR. HOLIAN: And we'll take that in particular for, you know, the full committee. Thank you.

MR. MEYER: As a summary for my part, it was not left out for any reason. It wasn't excluded because of --

MR. BARTON: Well, it just kind of makes you wonder when you don't talk about it what -- you know, what is it. You know.

MR. MEYER: Um-hum. And as to the resident inspectors going in during the outage, the problem with that tends to be that they're most

familiar with their site and since an industry standard for overall material condition is a little difficult to define, then we kind of default each inspector's standard and that really tends to be subjective. So.

MR. BARTON: I would hope their standards are really high.

MR. MEYER: Well, they may be, but their job is --

MR. BARTON: You're digging a deeper whole, Glenn. You can continue. I'm sorry.

MR. MEYER: So, as we said, we addressed aging management. We did look at the four amendments that were submitted to address these issues.

On the HPCI system review, we felt that aging effects had been addressed on HPCI and that the coverage of the aging management programs was appropriate for aging management --

MEMBER ABDEL-KHALIK: The HPCI system review involved a review of all the system health reports for the past several quarters --

MR. MEYER: Yes.

MEMBER ABDEL-KHALIk: -- and/or --

MR. MEYER: Yes.

MEMBER ABDEL-KHALIK: -- observation of

the system during tests or was it just a walkdown?

MR. MEYER: I don't think there were tests that we were able to observe. It was walkdown of the system. We did look at the health reports because they tend to highlight any problems they've had that we would follow-up on.

MEMBER ABDEL-KHALIK: So, the inspector never really saw the pumps running?

MR. MEYER: I can't state for sure. I don't recall that -- the pumps running.

MEMBER ABDEL-KHALIK: Okay.

MR. MEYER: It's a --

MEMBER ABDEL-KHALIK: You would have no indication, for example, on level of vibration associated with the pump operation?

MR. MEYER: No, but the --

MEMBER ABDEL-KHALIK: You can get that from the system health reports?

MR. MEYER: The monthly test would certainly look at function, you know, pressure and flow and things like that, but they also do check vibration. We can see at the monitor locations the kind of vibration they've had and it would be something we would look at.

MEMBER ABDEL-KHALIK: And historically,

there have been no problems and no obsolescence issues associated with subcomponents of the systems?

MR. MEYER: I can't talk to that. I don't have those details. I could get them if that's worthwhile.

MEMBER SIEBER: Well, pumps themselves are active components as opposed to the license renewal rule which deals with passive components.

MEMBER ABDEL-KHALIK: Are there any -- perhaps I should direct my question to the applicant. Are there any obsolescence issues associated with subcomponents of the HPCI system?

MR. D'ANGELO: I think in general the station health reports on any system do address obsolescence of subcomponents required to that system.

Nick D'Angelo, Station Manager of Engineering.

In general, station health reports have a section on obsolescence and certainly in HPCI, there are components that we have an obsolescence program and are working now, you know, through a CAP process to, you know, develop suitable replacements for those.

To be able to answer directly is there one specific component we're, you know, concerned about right now, the answer is no. We have sufficient

spares, sufficient replacements and are sufficiently ahead of any shortages we have of parts that we don't have a direct impact on station operation now.

That is addressed in station health.

MR. MEYER: On the aging management programs, we can concluded that the proposed activities are capable of managing aging effects.

Our inspection conclusions, we concluded that the scoping of non-safety system, structures and components and the aging management programs are acceptable. Our inspection results support a conclusion of reasonable assurance that aging effects will be managed and attendant functions will be maintained during the period of extended operation.

I'd also like to briefly address current performance. Both the Susquehanna units are in the Licensee Response Column of the action make-up which is the lowest level of regulatory oversight and that's based on all of our -- the inspection findings have been green and that the performance indicators are also green as shown on the slide.

And that concludes my remarks.

MS. GETTYS: Section 3 of the SER, this is the following sections. I do not plan to cover each subsection, but we'll touch on those which have

information of interest.

Section 3.0.3 contains the staff's review of the applicant's aging management programs. There's 52 AMPs that were viewed by the staff. Twenty are new programs. Thirty-two are existing programs. Twenty-eight were identified as consistent with GALL. Seven with exceptions. Eleven -- excuse me. Seven with enhancements. Eleven with exceptions and two with both enhancements and exceptions. Four were identified as plant-specific programs.

MEMBER BONACA: The 52 AMPs, is it the total number of AMPs or is it only the total number of AMPs reviewed by the staff?

MS. GETTYS: It's the total that was reviewed by the staff.

MEMBER BONACA: Oh, number of AMPs larger?

MS. GETTYS: I'm sorry.

MEMBER BONACA: So, the number of AMPs for this plant is larger than 52?

MR. ROBINSON: There are 52 AMPs and they were all reviewed by the staff.

MEMBER BONACA: Oh, okay. Okay.

MS. GETTYS: I think the next slide will help clear this up. During the staff's review, two aging management programs were added. They are the

preventive maintenance activity of the main turbine. This was an existing program that Susquehanna was not taking credit for.

The next one that was added was the fuse holder program. It was added because the program was needed to manage aging for fuse holders.

The main steam flow restrictor inspection program was a new program that the plant had added for the LRA, but during the review of the AMP, it was deleted based on the GALL recommendations that the AMP was not needed.

MEMBER ABDEL-KHALIK: The concern there is change in flow diameter or something? What is the concern with the inspection of the main steam flow restrictor?

MR. BARTON: Whether the flow restrictor will grow. As age goes on, it gets larger and larger. That's the issue here.

MEMBER ABDEL-KHALIK: And the determination was made that over the years the flow diameter in the restrictor has not changed? Is that why it was renewed?

MS. GETTYS: It was that it wasn't -- there were other programs that were covering aging for that. This particular program wasn't needed. It was

removed by the applicant.

MR. BARTON: I don't remember that. I thought it said something to do with insignificant change or something that -- I don't remember. Somebody who reviewed this ought to know the answer.

MS. GETTYS: Erach Patel is --

MEMBER ABDEL-KHALIK: Could the applicant perhaps explain this?

MR. PATEL: Hi. I'm Erach Patel. I reviewed that program and there were three aging effects on the main stream flow restrictor. Loss of material, cracking and they had reduction of fracture toughness due to the thermal embrittlement.

This program was originally put in there for thermal embrittlement. When you look at the GALL enbrittlement AMPN 12, it provides a screening criteria which says that if the material is centrifugally cast there might have been material, but then you don't have this aging effect of thermal embrittlement and based on that, that program was not required.

But, they did have loss of material and cracking of the same component managed by ISI program and water chemistry.

MEMBER ABDEL-KHALIK: Other programs. All

right.

MR. PATEL: So, they're managing the cracking and loss of material, but you didn't need for thermal embrittlement.

MEMBER ARMIJO: So, this was eliminated based on the material chemistry --

MR. PATEL: That is correct.

MEMBER ARMIJO: -- and microstructure of these cast components?

MR. PATEL: Right. Right. Right.

MEMBER ARMIJO: But, it --

MR. PATEL: And the guideline is very clear. That if it's centrifugally cast material that aging effect is not a susceptible aging effect.

MEMBER ARMIJO: Okay.

MS. GETTYS: Thank you, Erach.

MEMBER SIEBER: Before we get too far, the applicant's slide 15 and your slide 21, the numbers there don't agree.

MS. GETTYS: Fifty-one?

MEMBER SIEBER: Applicant's 15 and your 21. The applicant says there is 52 aging management programs. You say 51. He says there is 13 exceptions. You say 11. So, maybe before we finish you can tell us which slide is --

MS. GETTYS: My slide represents what came in the LRA and if anything changed about those programs, it's contained in the SER. I believe the applicant and I believe what their numbers come from after the review was done what the changes were.

MEMBER SIEBER: So, if I were to bet, I would bet on the applicant's slide?

MR. MEYER: For current conditions.

MEMBER SIEBER: Okay. Thanks.

MEMBER ABDEL-KHALIK: Back to the flow restrictor inspection program. I guess the comment was made that the loss of material is covered in some other program.

MS. GETTYS: Yes. I believe --

MEMBER ABDEL-KHALIK: Are there data that would suggest a change in the flow diameter of these flow restrictors over the past 20 years? How are they inspected? How is the loss of material indicated? How does one measure a change in the flow diameter of the flow restrictor?

MR. PATEL: They're using the ISI program. ISI program.

MEMBER ABDEL-KHALIK: If the flow diameter is 16 inches at time zero when the plant started, what is it now and how do they find out?

MR. PATEL: Well, loss of material basically is for pitting more than anything else.

MEMBER ARMIJO: Well, there's a visual and mechanical measurement -- dimensional measurement?

MR. PATEL: Well, they look for pitting. That's the loss of -- the aging mechanism is pitting because of it's -- it's stainless material. You got your water chemistry, but you could have some pitting involved and that's what they look for.

MEMBER ABDEL-KHALIK: And how is that done? Visually?

MR. PATEL: Visually.

MEMBER ABDEL-KHALIK: It's not defined?

MEMBER SIEBER: Well, it's usually in a flange. If it's a ventory, it's a section. If it's just a diaphragm, there's a flange there. So, you take that apart and pull the -- there's an edge that comes out. Then you know where it is.

MR. PATEL: There's a pipe based upon the components. So, it's within the pipe itself. It's not an external component.

MEMBER ABDEL-KHALIK: Yes, I understand.

MEMBER BROWN: Are these measurement flow restrictors you're talking about or just flow restrictors?

MR. PELTON: This is Dave Pelton from License Renewal.

You know, if the licensee has a question, maybe they can address it a little later. Give you a chance to talk it through. But, what we'll do in our end is we'll make sure that -- well, you know, like we said, we certainly have a number of aging management programs we do apply to these components and we can do a review and get back to the members. Just give you a feel for what do we do and what do we expect the licensee, do the dimensional check, a visual check, et cetera. We'll get that to you.

MEMBER ABDEL-KHALIK: Yes, just trying to figure out how real is this. What does it -- how is this program conducted?

MR. PELTON: Good question and we'll get back to you on that.

MS. GETTYS: This table shows the groundwater sampling, the pH, the chloride and the stuff that -- okay. I'll talk louder. Susquehanna's groundwater is non-aggressive for steel imbedded and concrete.

The staff did inspect several manholes and found water in number 2 and number 16. The water in the manholes is a generic current operating issue that

is being addressed by the Division of Engineering.

Based on its audit and review and the additional information submitted as a result of the --

MEMBER BROWN: Could I interrupt a minute?

MS. GETTYS: Yes.

MEMBER BROWN: Well, I think I didn't expand on a question that I asked about how they determined the inspection frequency and somebody answered the question relative to -- that you measured stuff over an eight-month period, determined how fast they filled up and what you had to do and it was -- and John asked the question is that -- how do you implement that and I think you said about preventative maintenance.

Have you implemented that now? Are you doing that now every -- and I didn't ask what the periodicity was. Or is that something that you're going to do when you go into the extension period or what? I mean since you found it, is it now a current PM where you're actively measuring or checking these things every year or every two months or every -- you did it every month I think you commented for the eight-month period.

MR. BRADY: Yes, this is Phil Brady.

That's true. We did do the inspection

over an eight-month period. Inspected basically those manholes to look at what water rate was input.

At the time, we, in fact, didn't continue that effort as far as the pump down. So, as pointed out here, we, in fact, did see water later.

We have, at this point, implemented the PMs and are in the process of implementing them and the frequency is adjusted based on the actual intake results that we had seen previously to assure we maintain the water level below the medium voltage cables.

So, the periodicity range is anywhere from three months up to, I think, 18 months was what we had looked at for the various manholes based on what we had seen in the previous inspection.

MEMBER BROWN: You determined over an eight-month period that it takes 18 months to refill.

MR. BRADY: That's correct. That's -- yes, there's some intervals that the water intake was very low.

MEMBER BROWN: Okay. So, you calculated?

MR. BRADY: Yes.

MEMBER BROWN: All right.

MR. BRADY: Yes.

MEMBER BROWN: You did it analytically

from that point.

MR. BRADY: That's correct.

MEMBER BROWN: But, you are in the process of executing those PMs, those inspections now as opposed to -- because you found that you did not keep them submerged obviously.

MR. BRADY: That is correct.

MEMBER BROWN: Okay.

MR. BRADY: Based on the industry involvement and the issues that continue to proceed on this issue, we have, in fact, put those PMs in place and, in fact, are in the process of implementing those.

MEMBER ABDEL-KHALIK: If the primary source of water intrusion is rain rather than seepage of groundwater, what would a frequency of pumping out based on data collected over an eight-month period give you? Why is that relevant? Why isn't it something that you would do every time it rains?

MR. BRADY: The manhole structures are fairly deep and so, when we looked at the periodicity and the rain, we had had some very large rainstorms during the period of time that we did the measurement over the eight-month period. So, in looking at that and looking at the rate of intake into the manholes,

we felt very comfortable that we were enveloping in what would be a severe rainstorm.

The water level has to get to a very high height in most of these manholes in order to be an impact on the medium voltage cables. The medium voltage cables are normally at the very highest level within the manhole structure.

MEMBER ABDEL-KHALIK: Well, how deep are these manholes?

MR. BRADY: They vary. They vary. I would say normally they're about 10-foot deep. Is, I guess, the standard large electrical manholes that we have at the plant, but you could have some that are a little bit smaller and not quite as deep. Depending on the application.

MEMBER ABDEL-KHALIK: And there are no sensors that would tell you what the water level in those manholes --

MR. BRADY: That is correct. There's no level indication, automatic sensors or alarms that would indicate that.

We do have a sump location in the manhole. So, when we do go to pump it out, we have a location where we can put the sump to assure we pump it dry, but we do not have the level indication at this point.

So, the inspection effort will really be our input to that determination.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER BROWN: Thank you, Evelyn, for my interruption.

MR. PELTON: This is Dave Pelton.

Let me just add one more aspect to that. You know, a program is so predicated on operating experience and this is no different. Where a licensee, you know, regardless of the particular study and the scope of that study they do, we would still expect that they would inform their program using current operating experience and if necessary, make adjustments on hey, you know, bad -- whatever the cause is. So, and we will have opportunities in the future to do follow-up commitment inspections and other things that give us the opportunity to look at their operating experience and make a call as to whether their current program is informed.

MS. GETTYS: On conclusion of the AMPs, based on its audit and review and the additional information submitted as a result of the REIs, the staff concluded that the affects of aging will be managed so that intended functions will be maintained consistent with the CLB during the period of extended

operation.

Section 3.3.2.2.6, this is an emerging issue that came up after the SER was issued. The staff is in the process of requesting additional information regarding neutron-absorbing material, Boral, in the spent fuel pool. The staff has a path for this and will provide the applicant with REIs. The SER will be revised accordingly.

Based on its review of the LRA and additional information submitted as a result of the REIs, the staff concluded that except for the Boral issue in section 3.3.2.2.6, the aging effects will be managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

Some of Susquehanna's reactor vessel beltline welds do not have unirradiated Charpy upper shelf values -- energy values. To determine that this -- to demonstrate that these welds have adequate fraction toughness, the applicant performed equivalent margin analysis for the welds' material.

The equivalent margin analysis demonstrates that the reactor vessel will have a margin of safety against fracture equivalent to that required by Appendix G of Section 11 of the AMSE code

and will satisfy the requirements so that Appendix G of 10 CFR 50 will continue until the end of the period of standard operation.

This slide is a summary slide of the results for the equivalent margin analysis.

In section 4.3 of the SER, the staff documents its review of the metal fatigue of the piping and components TLAA. The 60-year fatigue analysis was performed on the applicable high-fatigue locations identified in NUREG/CR 6260. The applicant managed the fatigue for all the Class 1 components using the Metal Fatigue of the Reactor Coolant Pressure Boundary Aging Management Program in accordance to 10 CFR 54.21(c)(1)(iii).

Since the issuance of the SER with open items, the staff identified an area in which additional information is needed. Specifically, the feedwater system. The staff is requesting data on the dissolved oxygen values prior to 1994. The applicant has previous provided data for the dissolved oxygen from 1994 through 2007. The staff will issue a formal RAI to request the dissolved oxygen data for certain periods between plant startup and 1993.

In addition to the dissolved oxygen concentration issue just mentioned, the staff will

also request additional information on the following items shown on this slide. The staff will view the information provided by the applicant and document the findings in the final SER accordingly.

Based on it's review --

MEMBER ABDEL-KHALIK: Does the applicant have the historical data for the dissolved oxygen data for the period that you have requested?

MS. GETTYS: Yes, I believe they do.

MR. BARTON: I'm sorry. Go ahead. I didn't mean to cut in, Evelyn. Were you finished?

MS. GETTYS: Yes, sir.

MR. BARTON: How many actual open items are there against this application right now? None?

MS. GETTYS: These are emerging issues that came up after we issued the SER. So, these are things that we're addressing now.

MR. PELTON: This is Dave Pelton.

You know, this is a 22-month process and our tech staff and peer reviews, et cetera, et cetera as they find these technical issues, we can't always promise that they'll all be found resolved and fully fleshed out prior to the ACS subcommittee.

But, the way we will treat these, you know, in generic terms is well, we're just looking to

validate data. We'll probably -- we'll look at them like we would any confirmatory item. Where right now we don't believe that there's an issue with the methodology used to evaluate metal fatigue. However, we want to validate some of the data that was used to make sure that their assumptions were bounded.

MR. BARTON: But, on some list, there's some kind of item?

MR. PELTON: Yes, we will address it fully at the -- in our final meeting with you for the full committee.

MEMBER ARMIJO: You'll have all that data and the analysis done?

MR. PELTON: Absolutely.

MEMBER ARMIJO: Okay.

MR. PELTON: Absolutely. As a matter of fact, we'll have a slide I can promise you that will be specific to these items include the Boral issue and what's a little bit different about the Boral issue is that's likely going to cause either a new commitment to be added or an adjustment made to an existing commitment. So, had we -- you know, we -- you know, had we identified this, you know, a couple of weeks ago, we would have had time to call that like a formal open item if you will. But, we're tracking them the

same way nonetheless and we'll have a full story to tell at the final meeting.

MEMBER ARMIJO: But, they'd have to make a commitment even if they weren't requesting license renewal. I mean this is a current problem with the Boral. So, all plants are going to have to address it in some way.

MR. PELTON: That's exactly right and again, you know, just to that point, you know, we're looking at all these generically across all of our plants and that's -- frankly, that's how we, you know, have included these today is in our generic reviews and peer reviews to make sure that we're consistent with all of our applications.

MS. GETTYS: Based on its review, the staff concluded that the applicant provided an adequate list of TLAAs. The staff concluded that the TLAAs will remain valid for the period of extended operation. TLAAs have been projected to the end of the period of extended operation. The aging effects will be managed for the period of extended operations.

MEMBER ABDEL-KHALIK: Back to the previous slide 31.

MS. GETTYS: Yes.

MEMBER ABDEL-KHALIK: What are your

questions about cycle counting?

MS. GETTYS: They're being developed. Those REIs are.

MR. PELTON: Well, we have a member of -- this is Dave Pelton. We have a member of the staff who can come up and talk a little bit about some of the questions we plan to ask the licensee.

MR. YANG: My name's Chuang Yang, NRR. I'm new member of DOR and the originally bureau of this fatigue -- metal fatigue and I just continue with the work.

Okay. On the -- for the fatigue analysis, the most important thing is the number of cycles. I like to see they have the cycle on track. Some detail and so, those cycles will go to the fatigue calculation and we would like to know whether there's any period of time that data was not tracked and so, this is the -- this is the main part of the fatigue evaluation and also, we like to know whether the program confirm that the transient supported by the design transient that will ensure that the stress is within the original stress analysis.

So, basically, we want to know the actual cycles which go to fatigue calculation and also like to see -- one of the application, the tables of

fatigue projection, the cycle projection and the fatigue value projection have some -- of some thing. I like to know whether they are consistent or not because if the cycles -- the projected cycle and the projected fatigue in the non-environmental fatigue area, I like to see whether they continually, you know, projected for the fatigue part.

MEMBER STETKAR: Are these -- I thought I read in the SER though several questions were asked about cycle counting and cycle projections and the conclusions were generally acceptable. So, this is --

MS. GETTYS: Additional questions being asked.

MEMBER STETKAR: Just because somebody else is looking at it or --

DR. LI: This is Sam Li. I'm, you know, with the last reveal.

We're asking REI, you know, in the process and they responded. They gave us cycles for the last ten years.

MEMBER STETKAR: Um-hum.

DR. LI: Okay. But, the plan had been, you know, in operation for more than ten years.

MEMBER STETKAR: Okay.

DR. LI: So, now before, give us the rest

of the data.

MEMBER STETKAR: Okay.

DR. LI: Okay. So, we can fully evaluate.

MEMBER STETKAR: Okay. I just -- I was --

CHAIR SHACK: Okay. So, I mean they've included that in their analysis. You just want to confirm --

DR. LI: That's right.

CHAIR SHACK: -- the cycle count.

DR. LI: They include it for the -- they actually gave us data up to the last ten years. I mean for the last ten years. We wanted to see what happened before the last ten years in terms of data. Just to confirm the analyses that you base on --

MEMBER STETKAR: Yes, I understand. They made their projections based on the average cycles per year, but only over the last ten-year operating period.

DR. LI: That's correct.

MEMBER STETKAR: So, you're asking now to extend --

DR. LI: Yes, to go back to the original operation and cover the gap.

MR. HOLIAN: This is Brian Holian.

It is confirmatory. The original reviewer

did review it and accept it based on their projections. We have the time. We've had questions even from this body to make sure that you do a good look back as best as we can. So, we have that time and we're asking those confirmatory questions.

MEMBER STETKAR: Okay. Thanks.

MS. GETTYS: In the SER with open items, the staff concluded that on the basis of its review of the LRA the staff determined that the requirements of 10 CFR 54.29(a) have been met. However, as previously mentioned, the staff has identified the need for additional information in a few areas in order to complete its review.

The staff will document its conclusion regarding the LRA of Susquehanna in the final SER which is currently scheduled to be issued August 2009.

That's all I have.

CHAIR SHACK: Any additional questions from the members?

MEMBER ARMIJO: Yes. Could you -- I may have misunderstood the -- your explanation of slide 28, the vessel neutron embrittlement. I thought I heard you mention that there was material that you didn't have, original vessel material Am I confused or -- exactly what happened with this analysis. Why

did you need a margins analysis with generic material as opposed to the actual vessel?

MS. GETTYS: Simon Sheng is coming to the -- speaking.

MR. SHENG: This is Simon Sheng, Associate with Division of Component Integrity. I'm the reviewer for the this issue.

In Susquehanna's case, okay, it's typical of BWR plants that for certain bottom line materials they don't have the initial upper shelf energy values. So, they have to result -- and this issue was discovered more than ten years ago. So, that the BWR Owners Group did a public report and using the so-called equivalent margin analysis and equivalent margin analysis is nothing but a elastic fracture mechanics analysis and using the GR curve as a resistance and using the applied stress intensity factor as a driving force.

And in that -- because they don't have that -- they don't have the initial upper shelf energy, so, what GE did was that they did statistic analysis on all the bottom line materials that BWR has. Which they have initial values. They didn't have values and see what's mean minus 2 standard division value and in one of the materials, they even

go lower than that. So, if any of the data fall below that mean minus two value, they use that as an initial upper energy value for this generic material.

So, GE did analysis and had several -- separate these materials into several groups and using this mean minus two sigma value to establish initial upper shelf energy value and they -- and then they use a very severe fluence to predict the reduction and then they start -- for instance, like they certify foot-pound. Is a value they established which is wholly supported by the elastic plastic fracture mechanical analysis and that initial value 59. Really upper shelf energy was established by that -- their statistical analysis I just mentioned and that 54 EFPY projected upper shelf energy was based on the 54 EFPY fluence. So --

MEMBER ARMIJO: At EPU conditions included in --

MR. SHENG: Yes. Yes.

MEMBER ARMIJO: Okay.

MR. SHENG: And you can see that the reductions of upper shelf energy or this generic analysis something like more than 23 percent in one case and probably more than 30 percent for another case and Susquehanna's passive analysis 04 within that

region of reduction. So, it's okay.

MEMBER ARMIJO: Okay. Thank you.

MR. SHENG: Thank you.

MEMBER ARMIJO: Yes. Understand.

MEMBER ABDEL-KHALIK: So, how is that Unit 1 lower intermediate shell number 2 and the Unit 2 weld number 3 determined to be the limiting locations?

MR. SHENG: For this case, as I said, that if you don't have initial upper shelf energy value, it's very, very hard for me to select a really limiting material and the reason I selected that one is because they don't have the initial upper value. They don't have test data to draw a curve so that they can determine the initial upper shelf energy. They only have one data point and that data point show very low value for that material. So, I just kind of selecting as a limiting upper shelf energy material. It's kind of arbitrary.

However, it's better in this case because in one case, I have the generic bottom line material. The plate material to cover that and in the second case, I also have the generic analysis for weld to cover this. So, basically, that this will be more complete.

MEMBER ARMIJO: Thank you.

CHAIR SHACK: Let me just ask this again. I can understand your upper shelf energy problem. Do you actually know the compositions of these materials?

MR. SHENG: Composition is chemical composition.

CHAIR SHACK: Chemical composition.

MR. SHENG: Yes, I do.

CHAIR SHACK: Okay. So, what you do is you use the statistic thing to determine the initial lower shelf and then you use your usual correlations to determine the embrittlement based on chemistry?

MR. SHENG: Yes, the deduction -- the reduction --

CHAIR SHACK: Reduction.

MR. SHENG: Plus there's reductions.

CHAIR SHACK: Okay.

MR. SHENG: So, it's not in that generic analysis. In the generic analysis, that's --

CHAIR SHACK: Yes, they just use --

MR. SHENG: -- that's also. Yes, it's just based on generic material.

CHAIR SHACK: But, then you do that calculation to show that your reduction isn't greater than that generic reduction.

MR. SHENG: It's smaller. My reduction is

smaller. Right.

CHAIR SHACK: Okay. That's what I thought.

MR. SHENG: Okay.

CHAIR SHACK: Yes.

MR. SHENG: Thank you.

CHAIR SHACK: Any other questions? Well, then I think we're through. I'd like to thank the licensee and the staff for it's presentations this morning. I think they've been helpful.

We understand we had some issues that still need to be resolved, but we'll be discussing those at the full committee meeting.

Thank you very much.

(Whereupon, the meeting was concluded at 11:56 a.m.)

Advisory Committee on Reactor Safeguards
License Renewal Subcommittee

Susquehanna Steam Electric Station Units No. 1 and 2

Safety Evaluation Report with Open Items

April 1, 2009

Evelyn Gettys, Project Manager
Office of Nuclear Reactor Regulation

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Protecting People and the Environment

Introduction

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

Overview

- LRA Submitted by letter dated Sept 13, 2006
- GE Boiling Water Reactor (BWR), Mark II containment
- Jan. 30, 2008 - Extended Power Uprate (EPU) was granted to SSES to operate at
  3952 MWth, 1300 MWe for Units 1 & 2
- Operating license for Unit 1- NPR-14 expires July 17, 2022
- Operating license for Unit 2- NPR-22 expires March 23, 2024
- Located approximately 7 miles NE of Berwick, PA

Overview

- Safety Evaluation Report with Open Items was issued March 2009
- 278 RAI's Issued
- 59 Commitments

Overview

- Scoping and Screening Methodology Audit
  - December 11 - 15, 2006
- Aging Management Programs (AMP) Audit
  - May 5 - 9, 2008
- Regional License Renewal Inspections
  - August 11 – 15, 2008
  - August 25 – 29, 2008

Section 2: Structures and Components Subject to Aging Management Review

Section 2.1–Scoping and Screening Methodology

- Applicant amended the LRA to include portions of (1) NSR piping attached to SR SSCs located within containment and (2) NSR piping attached to SR SSCs at containment penetrations and extending outside of containment, in accordance with 10 CFR 54.4(a)(2)
- Based on the review of the LRA and additional information submitted as a result of Requests for Additional Information (RAIs), the staff concluded that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1)

Section 2: Structures and Components Subject to Aging Management Review

Section 2.2 – Plant-Level Scoping Results

- Based on its review of the LRA and additional information submitted as the result of RAIs the staff concluded the applicant identified systems and structures within the scope of license renewal per 10 CFR 54.4

Section 2.3 – Scoping and Screening Results Mechanical Systems

- Based on its review of the LRA and additional information submitted as the result of RAIs the staff concluded that there were no omissions of structures or structural components from scope of license renewal in accordance with 10 CFR 54.4(a), and no omissions from AMR in accordance with 10 CFR 54.21(a)(1)

Section 2.4 – Scoping and Screening Results: Structures

- Based on its review of the LRA and additional information submitted as the result of RAIs the staff concluded that there were no omissions of structures or structural components from scope of license renewal in accordance with 10 CFR 54.4(a), and no omissions from AMR in accordance with 10 CFR 54.21(a)(1)

Section 2.5 – Scoping and Screening Results

Electrical and Instrumentation and Control Systems

- As a result of the staff's review, sections of the offsite switchyard were included in the scope of license renewal for Station Blackout (SBO) in accordance to 10 CFR 54.4(a)(3)
- Based on its review of the LRA and additional information submitted as the result of RAIs the staff concluded that there were no omissions of electrical and instrumentation and control system components from the scope of license renewal in accordance with 10 CFR 54.4(a), and no omissions from AMR in accordance with 10 CFR 54.21(a)(1)

Section 2.6 – Conclusion for Scoping and Screening

- The applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1)
- The applicant adequately identified those SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a) and those SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1)

License Renewal Inspections

Glenn Meyer

Region I Inspection Team Leader

Inspection Objectives

- Scoping of non-safety SSCs

- 12 New Aging Management Programs
- 17 Existing Aging Management Programs

- HPCI System Review

Scoping

- Scoping of non-safety SSCs – generally accurate and acceptable
- Structural and spatial interactions reviewed
- LRA Amendment to update HPCI cables in Turbine Building

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New AMPs

- Supplemental Pipe/Tank Inspection
- Buried Piping and Tanks Inspection
- Area-Based NSAS Inspection
- Chemistry Program Effectiveness Insp.
- Small Bore Class 1 Piping Inspection

Existing AMPs

- Structures Monitoring
- Masonry Wall
- Fuel Oil Chemistry
- Piping Corrosion
- Fire Water
- Instrument Air Monitoring
- System Walkdown
- Closed Cooling Water Chemistry
- Preventive Maintenance Activities –RCIC/HPCI Turbine Casings
- Leak Chase Channel Monitoring

HPCI System Review

- Aging effects have been addressed
- Coverage of AMPs was appropriate

AMP Conclusion

- Proposed activities are capable of managing aging effects

Inspection Conclusions

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

Current Performance

- Both units – Licensee Response Column
- All Findings – Green
- All Performance Indicators (PIs) - Green

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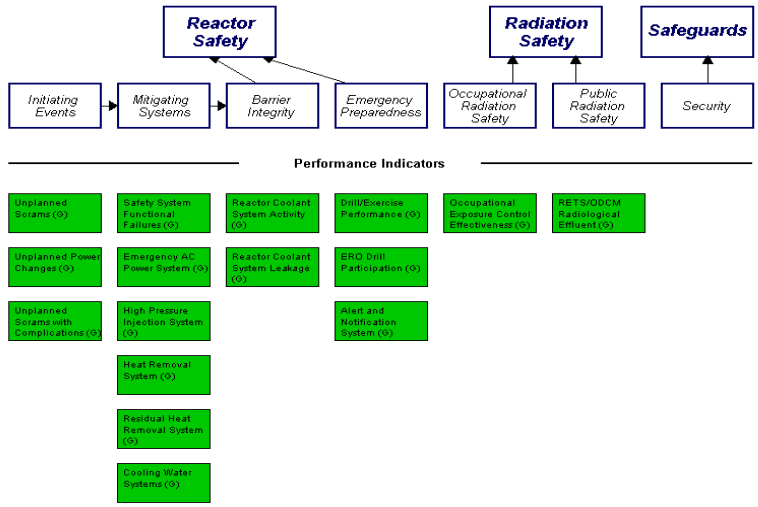
License Renewal Inspections



Last Modified: January 30, 2009

Section 3: Aging Management Review Results

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

Section 3.0.3 Aging Management Programs

- 52 AMPs reviewed by the Staff
  - 20 are New Programs
  - 32 are Existing Programs
- 28 were identified as consistent with GALL Report
- 7 with enhancements
- 11 with exceptions
- 2 with both enhancements and exceptions
- 4 were identified as plant-specific programs

Section 3.0.3 Aging Management Programs

- Preventive Maintenance Activities –Main Turbine (B.2.49) was added
- Fuse Holders Program (B.2.50) was added.
- Main Steam Flow Restrictor Inspection Program (B.2.26) was deleted.

Section 3.0.3 - AMPs

- Groundwater sampling for pH, chloride, and sulfate concentrations will be performed yearly during the period of extended operation.
- SSES Groundwater is non-aggressive

	Acceptance Criteria	2006	2007
pH	>5.5	6.11	6.13
Chlorides	<500 ppm	23.1 ppm	40.4 ppm
Sulfates	<1500 ppm	43.2 ppm	54.6 ppm

Section 3.0.3 – Non-EQ Inaccessible Medium-Voltage Cables Program

- Several manholes inspected during AMP audit and Regional inspection
  - Some submerged medium voltage cables found in manhole # 2
  - Water, but no submerged cables found in manholes # 16
- Water in manholes is a generic, current operating plant issue that is being addressed during the current period of operation through the reactor oversight process in accordance with the requirements of 10 CFR Part 50

Section 3.0.3 – AMPs

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

Section 3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

- Staff in process of requesting additional information regarding neutron absorbing material (Boral) in the Spent Fuel Pool
  - Surveillance of the material will continue until the end of the current operating license
  - Staff has concerns on whether any loss in neutron absorbing functionality will be adequately detected and managed in the period of extended operation

Section 3.7 Conclusion

- Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that except for issue of Boral in Section 3.3.2.2.6 the:
  - Aging effects will be managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, per 10 CFR 54.21(a)(3)

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Section 4.2: Reactor Vessel Neutron Embrittlement – Upper Shelf Energy (USE)

Reactor Vessel limiting material	Fluence (E>1 MeV) at 1/4T 10^{19} (n/cm^2)	Evaluation Using Equivalent Margins Analysis (Relevant Generic Material)		
		Unirradiated USE (ft-lb)	54 EFPY Projected USE (ft-lb)	EOL USE Acceptance Criteria (ft-lb)
Unit 1 Lower Intermediate Shell No. 2	0.0974	59	45	35
Unit 2 weld No. 3	0.0815	84.5	51.5	35

- **Section 4.3 – Metal Fatigue of Piping and Components**
  - 60-year fatigue analyses were performed for the applicable high-fatigue locations of NUREG/CR-6260
  - SSES Units 1 & 2 will manage fatigue of all Class 1 components using the Metal Fatigue of Reactor Coolant Pressure Boundary Aging Management Program

- **Section 4.3.3** – Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (GSI-190)
  - Feed Water System
    - Fen values calculated based on assumed DO (dissolved oxygen) concentration data lower than 0.05 ppm.
    - Applicant did not provide records of monitored DO data for time period before 1994
    - Staff awaiting confirmation of the DO level's historically maintained at SSES

Fatigue Monitoring Program

- The Staff has additional questions to ask on couple items
  - Transient monitoring and cycle counting
  - CUF values

Conclusion for TLAA

Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant provided an adequate list of TLAAs, per 10 CFR 54.3 and that except for the fatigue issues of 4.3.3 the:

- TLAAs will remain valid for the period of extended operation, per 10 CFR 54.21(c)(1)(i)
- TLAAs have been projected to the end of the period of extended operation, per 10 CFR 54.21(c)(1)(ii)
- Aging effects will be managed for the period of extended operation, per 10 CFR 54.21(c)(1)(iii)

Conclusion

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

Susquehanna Steam Electric Station

License Renewal ACRS Subcommittee Meeting

April 1, 2009

Introductions

- Rick Pagodin, General Manager – Engineering
- John Krais, Manager – Special Projects
- Nick D'Angelo, Manager – Station Engineering
- Dave Flyte, License Renewal Lead Engineer
- Subject Matter Experts and LR Project Team

Agenda

- Background
- Operating History
- Major Modifications
- License Renewal Team/Schedule
- Scoping Discussion
- Application of GALL
- Commitment Process
- Topics of Interest
- Summary

Background

- Location: Northeast Pennsylvania
- Plant Owners
  - PPL Susquehanna, LLC (90%)
  - Allegheny Electric Cooperative (10%)
- Licensee/Operator: PPL Susquehanna, LLC

Background

- Two Units - BWR/4
  - 3952 MWt
  - 1300 MWe
- General Electric (NSSS), Bechtel (AE)
- Ultimate Heat Sink – Spray Pond
- Turbine Cycle Cooling Provided By Natural Draft Towers
- Make-up Water – Susquehanna River

Operating History

Construction Permit	November 1973
Operating License (Unit 1/Unit 2)	July 1982/March 1984
Stretch Power Uprate ~4.5% (Unit 1/Unit 2)	February 1995/ April 1994
MUR Power Uprate ~1.5%	July 2001
LRA Submitted	September 2006
Extended Power Uprate ~14%	January 2008
License Expires (Unit 1/Unit 2)	July 2022/March 2024

Operating History

- Unit One
  - Refueling Outage 15 Completed in April 2008
  - First Step EPU Implemented May 2008
- Unit Two
  - Refueling Outage 13 Completed in April 2007
  - Record Continuous Run

Selected Major Modifications

- 5th Emergency Diesel Generator
- Generator Stator Rewind
- Feedwater Heater #3 and #4 Replacement
- Main Turbine Replacement
- Added Condensate Filtration System
- Hydrogen Water Chemistry/Depleted Zinc Oxide
- Main Transformer Replacement
- 4 KV Breaker Replacement
- River Water Makeup Piping Replacement

Selected Major Modifications

- 480 VAC MCC Bucket Replacement
- Jet Pump Labyrinth Seals
- Jet Pump Hold Down Beam Replacement
- Main Turbine Moisture Separator Vane Replacement
- MSIV Leakage Control Modifications
- Reactor Core Stability – OPRM Modifications
- RHRSW Pump Suction Bell Replacement
- Turbine Building Roof Replacement
- CREOASS Air Intake Relocation

License Renewal Team

- License Renewal Project Team
  - Project Initiated in 2002
  - PPL/AREVA Team Established in 2004
- LR Team Engaged with the Industry
  - NEI LR Task Force and Working Groups
  - Observed Audits/Inspections of Peer Plants
  - Participated in LR Peer Reviews
- Plant Subject Matter Experts Involved

License Renewal Schedule

- Schedule and EPU
  - LR and EPU Part of Special Projects Group
  - LRA Developed at EPU Conditions
  - LRA Submitted September 2006
  - EPU Submitted October 2006
  - NRC Safety Review on Hold ~ 1 Year Pending EPU Review/Approval
  - Environmental Review Continued
  - NRC Safety Review Resumed February 2008

License Renewal Project

- Scoping Discussion
- Application of GALL
- Time Limited Aging Analyses
- Commitment Process

License Renewal Project - Scoping

- Scoping
  - Process Consistent with NEI 95-10 Rev 6
  - Conservative "Spaces" Approach used for (a)(2) Scoping for Spatial Interaction
  - Mechanical Boundary Drawings Identify (a)(1), (a)(2) and (a)(3) In-Scope Components

License Renewal Project - GALL

- Aging Management Reviews
  - Followed NEI 95-10 Guidance for AMRs
  - Used NUREG-1801, GALL
  - 82% of AMR Line Items Consistent with GALL (used notes A-E)

License Renewal Project - GALL

- Aging Management Programs
  - 51 SSES Programs Credited for LR
    - 20 Existing Programs with No Change
    - 12 Existing Programs with Enhancements
    - 19 New Programs (10 One-Time Inspections)
  - GALL/Plant-Specific
    - 47 GALL Programs (13 with Exceptions)
    - 4 Plant-Specific Programs

License Renewal Project - GALL

- 13 SSES AMPs with Exceptions to GALL
- Aging Effects Effectively Managed
- Typical GALL AMP Exceptions
  - AMP Scope Differences
  - Use of Alternative Inspection/Monitoring Methods
  - Differences in Parameters Monitored, Detection of Aging Effects, and Preventive Actions

License Renewal Project - TLAA

- TLAA Identification/Disposition
  Consistent with NUREG-1800 and NEI 95-10

- TLAAs Dispositioned in Accordance with
  10 CFR 54.21(c)(1)

License Renewal Project - Commitments

- 59 Regulatory Commitments for License Renewal
- Entered into the SSES Commitment Tracking Process
- Commitments Assigned to Station Personnel for Implementation

Topics of Interest

Inspection of RHRSW/ESW Pipe Vault

- Material and Environment as Evaluated in LRA
  - Conditions in the Vault Were Dry
  - Pipes Wrapped per Design Drawings
- Visual Inspection Confirmed No Significant Degradation

Topics of Interest

Underground Medium Voltage Cables

- 15 kV Non Safety-Related Cables
  - 13.8 kV Offsite Power Supply Circuit from Startup Transformers to Turbine Building
    - 5 Manholes – Submerged MV Cables Observed in 2 Manholes
  - 13.8 kV Offsite Power Supply Circuit from Reactor Building to ESS Transformers
    - Short Run - No Manholes
- License Renewal Commitment, Prior to PEO
  - Test Offsite Power Supply Underground MV Cables
  - Inspect/Pump Manholes to Keep MV Cables from Exposure to Standing Water

Topics of Interest

Underground Medium Voltage Cables

- 5 kV Safety-Related Cables
  - 4.16 kV Emergency Diesel Generator, RHRSW and ESW System Cables
  - 10 Manholes – No Submerged MV Cables Observed During Inspections
  - Energized Less Than 25% of Time

Topics of Interest

SBO Recovery Scoping

- Offsite Power Supply Scoping Boundary for Station Blackout Recovery is per the Latest Staff Guidance
- Includes 230 kV Circuit Breakers in Three Switchyards

Summary

- LRA Conforms to Regulatory Requirements and Follows Industry Guidance
- SSES Will Manage Aging in the Period of Extended Operation