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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

February 8, 2006

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING

+ + + + +

WEDNESDAY,

FEBRUARY 8, 2006

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 1:30 p.m., JOHN D. SIEBER, Chair, presiding.

ACRS MEMBERS PRESENT:

JOHN D. SIEBER, Chair
MARIO V. BONACA
OTTO L. MAYNARD
WILLIAM J. SHACK
GRAHAM B. WALLIS

ACRS STAFF PRESENT:

JOHN G. LAMB ACRS Staff Engineer

NRR STAFF PRESENT:

HANS ASHER

GREG CRANSTON

FRANK GILLESPIE

MAURICE HEATH

CAUDLE JULIAN

P.T. KUO

JIM MEDOFF

SIKHINDRA MITRA

BILL ROGERS

JAKE ZIMMERMAN

PROGRESS ENERGY STAFF PRESENT:

LENNY BELLER

TIMOTHY CLEARY

MARK GRANTHAM

MICHAEL HEATH

JEFF LANE

CHRIS MALLNER

GARRY MILLER

I-N-D-E-X

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

(1:31 p.m.)

OPENING REMARKS

CHAIRMAN SIEBER: This meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. My name is John Sieber, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Dr. Graham Wallis and Dr. William Shack, Dr. Mario Bonaca. To my right is John Lamb of the ACRS staff, who is the designated federal official for this meeting.

Would you introduce yourself, please?

MEMBER MAYNARD: I'm the newest member of the ACRS. I'm Otto Maynard.

CHAIRMAN SIEBER: Thank you.

The purpose of this meeting is to discuss the license renewal application for the Brunswick steam electric plant, units I and II. We will hear presentations from the representatives of the Office of Nuclear Reactor Regulation, the region II office, and Carolina Power and Light Company.

The subcommittee will gather information, analyze relevant issues and facts, and formulate a proposed position and action as appropriate for deliberation by the full committee during its meeting this week.

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the Federal Register on January 25th, 2006. 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 may be readily heard.

I would also ask that, particularly if you make a statement or answer a question, that you make sure that you signed in on the logs in back of this post here so that the transcribing stenographer knows who you are and what your name is so that the transcript may be accurate and complete.

We will now proceed with the meeting. And I call upon Mr. P. T. Kuo of the Office of Nuclear Reactor Regulation to begin.

MR. KUO: Thank you, Mr. Chairman.

STAFF INTRODUCTION

MR. KUO: This is P. T. Kuo, the Deputy Director of the Division of License Renewal. To my right is Mr. Jake Zimmerman. He's the Branch Chief for the License Renewal B Branch. And to my far right is Mr. S. K. Mitra. He's the project manager for this project for the staff review.

S. K. will be making the briefing for the staff on the SER that we prepared. And Jake is going to run the meeting today. We also have our inspection team leader, Caudle Julian, from region II. He's here to make a briefing to the staff on the inspection results.

We also have all of the technical support staff sitting here in the audience. They will be ready to answer any of the questions you might have.

So, with that, I will pass it to Jake.

MR. ZIMMERMAN: Good afternoon. Again, my name is Jake Zimmerman. I am the Branch Chief for Branch B. That is the projects branch.

One additional person I would like to also recognize is Dr. Ken Chang is here with us today. Dr. Chang is now the Branch Chief for Branch C, which is the Aging Management Audit Branch. That was the branch that I used to have. Dr. Chang took over for me in January, and I moved over to Branch B.

Louise Lund, who could not be with us today, is the other branch chief for the project side. She has License Renewal Branch A.

Just so you all know the way we're structured now, branch A will be all of the projects for the applications that are under review. Branch B, my branch, will have application reviews but also infrastructure review. The GALL update, all the license renewal documents that were recently updated, infrastructure work will now fall under me. And Dr. Chang will have the audit activities.

With that, I will turn it back over to you, Chairman Sieber.

CHAIRMAN SIEBER: Do you want to introduce the applicant?

MR. KUO: Yes. Now we want to turn the presentation to the applicant. This is Brunswick. Please take it over.

MR. MIKE HEATH: Thank you.

BRUNSWICK LICENSE RENEWAL APPLICATION

MR. MIKE HEATH: My name is Mike Heath. And I am the license renewal supervisor for the Brunswick plant. With me up here today I have Lenny Beller, who is the Brunswick licensing supervisor;

Mark Grantham, who is the design engineering superintendent at Brunswick.

With us from the plant, we also have Tim Cleary, who is the Director of Site Operations. From the license renewal organization, we have Joe Donahue, who is the Vice President of Nuclear Engineering; Garry Miller, who is the Manager of License Renewal. And from the Brunswick license renewal staff, we have Chris Mallner, Jeff Lane, Mike Fletcher, and Ed Williams.

We want to give you a little bit of background on the Brunswick plant today, talk about how we developed our application. To do that, we will start off with a description of the Brunswick plant, give you an operating history, talk about our current plant status. Those three items will be handled by Mr. Beller.

Then we will be discussing our application background, get into our review methodology, discuss how we apply GALL, and then have some discussion on our commitment process.

So, with that, I will turn that over to Mr. Beller.

B. DESCRIPTION OF BRUNSWICK

MR. BELLER: Good afternoon. As Mr. Heath said, my name is Lenny Beller. I am supervisor of licensing at Brunswick.

Brunswick is a dual-unit GE BWR 4 with a Mark I containment. We are located in Southport, North Carolina on the Cape Fear River. The Cape Fear River is our ultimate heat sink.

MEMBER WALLIS: It's a year-round river? There are no fluctuations of any significance in the flow?

MR. BELLER: That's correct, sir. We are a 218-inch vessel. So we're one of the smaller BWR-4s with 560 fuel assemblies per unit. And we are a hydrogen water chemistry plant.

MEMBER SHACK: Now, do you use noble metal, too?

MR. BELLER: No, sir, hydrogen water chemistry only.

MEMBER SHACK: Now, your license renewal application doesn't commit you to use hydrogen water chemistry, as I understand it, right?

MR. MIKE HEATH: No, sir. We are not using hydrogen water chemistry as a commitment.

MEMBER SHACK: As a commitment.

MR. MIKE HEATH: We are a hydrogen water chemistry plant.

MR. BELLER: At this time we were asked some questions prior to the meeting regarding our primary containment and recirc piping. And I would like to turn it over to Mr. Grantham.

MR. GRANTHAM: Good afternoon. This is Mark Grantham again. I am the superintendent of design engineering.

Brunswick has a unique Mark I containment. We are the only Mark I containment that actually has the suppression-poor torus encapsulated in concrete. The other sites have a freestanding torus that is supported.

MEMBER WALLIS: Now, that torus is pretty big. The thickness of that concrete in places is quite remarkable, isn't it?

MR. GRANTHAM: That is correct. It's on the order of three to four feet thick.

MEMBER WALLIS: Or even more in the corners.

MR. GRANTHAM: Correct.

MEMBER WALLIS: Minimum is three to four feet.

MR. GRANTHAM: Correct.

CHAIRMAN SIEBER: Now, the metallic part of the torus acts as a liner, as opposed to a structural member. Is that correct?

MR. GRANTHAM: That is correct. There is a liner on the inside of the concrete that --

CHAIRMAN SIEBER: Right.

MR. GRANTHAM: -- provides a --

CHAIRMAN SIEBER: And the concrete itself is the structural member?

MR. GRANTHAM: That's correct.

CHAIRMAN SIEBER: Okay.

MR. GRANTHAM: Any other questions regarding specifically the Mark I containment?

MEMBER BONACA: Given the unique configuration, I mean, how did you address the issue of leakage from seals, the refueling seals?

MR. GRANTHAM: From refueling seals? Well, we have observed no leakage from the refueling seal. Again, there is a barrier of concrete that goes directly against the containment liner.

MEMBER BONACA: That's why I was asking the question. It's a unique configuration there.

MR. GRANTHAM: We have in the past observed some corrosion between the concrete and liner. That primarily occurred due to issues during construction where construction debris was left in place between the liner and the concrete at the personal access hatch. There is actually a felt coating between the liner in the concrete that during construction became wet and when the concrete was poured served as a mechanism to allow corrosion.

MEMBER BONACA: Okay.

MR. GRANTHAM: Due to the construction with the liner and the concrete, whenever that corrosion occurs, just the expansion of the corrosion products provides bulging.

So our IWE program specifically looks for bulging on the containment liner as a method for identification of any type of corrosion between the actual liner and --

MEMBER WALLIS: How much bulging can you detect?

MR. GRANTHAM: We actually go out with straightedges. It is fairly visible.

MEMBER WALLIS: So you can detect what, an eighth of an inch or something or less than that?

MR. GRANTHAM: Yes, eighth of an inch.

MEMBER WALLIS: Would that mean there is an eighth of an inch corrosion behind it or more?

MR. GRANTHAM: Well, when you have corrosion, the corrosion product expands quite a bit more than the actual metal loss. So it does not take a lot of metal loss to start the --

MEMBER SHACK: Do you have a quantitative feel for how much metal loss you can have before you detect it from experience?

MR. GRANTHAM: No. Based on our experience, particularly a couple of outages ago, we had a bulging in the personnel access hatch. We did not encroach it on min wall when we went in. We went in and did UTs. Now, we did go in and do the other --

MEMBER SHACK: Oh, that's what you do? You come in and you do a UT from the back --

MR. GRANTHAM: Correct.

MEMBER SHACK: -- to find out how much is left?

MR. GRANTHAM: That is correct. And that is fairly standard if we find bulging to go in and do UTs so we know exactly what level of metal we have there.

MEMBER SHACK: Now, do you do inspections of the linear in the torus, too?

MR. GRANTHAM: That is correct. In the error region, that is part of the IWE program. We do go in and do inspections of that region.

MEMBER BONACA: So essentially from your configuration, you don't feel that you have the concern regarding leakage from the fueling seal?

MR. GRANTHAM: No, sir, we do not.

MEMBER BONACA: And that is something that the staff has accepted, too?

CHAIRMAN SIEBER: On the other hand, large concrete structures like this, another example would be a large dry PWR-type containment. When you construct that, the concrete cracks. And so there is a pathway for ingress of oxygen to the inside of the liner. And your liner is carved in steel, right?

MR. GRANTHAM: That is correct.

CHAIRMAN SIEBER: So you have an opportunity for moisture. At least from the outside in, you have an opportunity to get oxygen in there on carbon steel. So it's a natural place for corrosion to occur.

Do you do any kind of volumetric examination of the liner? And if so, how do you do it?

MR. GRANTHAM: No volumetric other than, well, we do UTs for thickness measurement, no other volumetric --

MEMBER WALLIS: How thick is the liner?

MR. GRANTHAM: The drywell liner is five-sixteenths-inch thick.

MEMBER WALLIS: Now, at half an inch or --

MR. GRANTHAM: Suppression pool liner is three-eighths of an inch. I will say the areas where we have found degradation, we actually cut out a portion of the liner and found the corrosion products on the back side were, in fact, dry. And there was no active corrosion that was going on there.

MEMBER WALLIS: So do you have a way of predicting from any in-service examination that you perform how much material you have left that can corrode before you lose integrity of the torus or any part of containment? Do you have a way to do that or does your ISI program say it's good today and it was good yesterday, but I don't know about tomorrow?

MR. GRANTHAM: Well, we do frequent inspections. And, again, we do do ultrasonic thickness measurements. We do have a minimum thickness.

MEMBER WALLIS: Okay. That's sort of a volumetric technique.

MR. GRANTHAM: Correct.

MEMBER WALLIS: Sort of.

MR. BELLER: Plus, anything that we find in one unit, we will obviously take that operating experience and go look in the opposite unit to make sure that that failure mode is not present there as well.

MEMBER WALLIS: Okay.

MEMBER BONACA: So, to summarize, what I hear is that whatever corrosion you have is historical, seems to be historical, --

MR. GRANTHAM: Correct.

MEMBER BONACA: -- came in from the initial construction.

MR. GRANTHAM: That is correct.

MEMBER BONACA: And so I guess there should be an objective of verification, I mean, as you go forth, that you don't have any --

MR. GRANTHAM: That's correct. Our IWE program is an ongoing program where we inspect essentially 100 percent degree ISI interval.

MEMBER BONACA: Now, should you have leakage from those seals -- and you said that you don't, but should you have it, in that configuration, you have no way for it to penetrate between the concrete and the metal?

MR. GRANTHAM: I believe that is the case. We have seen no evidence of that.

CHAIRMAN SIEBER: So your aging management program for containment consists of doing in the future what you are doing today?

MR. GRANTHAM: That is correct. It is implementation of our section 11 IWE and IWL programs.

MEMBER MAYNARD: When you found corrosion through the bulging, did you typically just do the UT and then monitor that in the future or did you cut it out and repair it?

MR. GRANTHAM: We did well repairs in some instances. We had actually one area that had gone through while in the containment liner, where it was a wet glove from construction was left between the liner and the concrete. That area actually went through while we cut out that area and replaced it. That is correct. But where we have found them, where they encroach on --

MEMBER BONACA: What do you mean "went through," I mean, like the roof?

MR. GRANTHAM: Through the liner. That's correct.

CHAIRMAN SIEBER: Yes. So at that point, you did not have containment integrity?

MR. GRANTHAM: We did do a test of the through-walled area, a localized test up to containment pressure, accident pressure. It did, in fact, pass. That is correct.

MEMBER BONACA: So you provided that.

CHAIRMAN SIEBER: Well --

MEMBER WALLIS: This is just a wet glove?

MR. GRANTHAM: That is correct. The design of this is there are Nelson studs welded to the liner that go into the concrete. It appeared that a glove was dropped during construction. And that landed on one of the Nelson studs before the concrete was actually poured.

MEMBER WALLIS: There is still a pretty rapid corrosion rate replacing carbon steel. The oxygen has got to get there from somewhere. The glove doesn't provide the oxygen.

CHAIRMAN SIEBER: Well, this is an inertic containment, right?

MR. GRANTHAM: That is correct.

MEMBER WALLIS: That's from the outside.

CHAIRMAN SIEBER: But the oxygen can attack --

MEMBER WALLIS: From the outside.

CHAIRMAN SIEBER: -- from the outside.

MEMBER WALLIS: Right. But there are plenty of trucks driving around with chassis that are not as thick as that that didn't corrode away. They're subject to the elements. So this just seems a rapid corrosion rate to me.

CHAIRMAN SIEBER: Well, there aren't very many 60-year-old trucks driving around.

MEMBER WALLIS: There are some pretty old trucks.

CHAIRMAN SIEBER: Okay.

MEMBER WALLIS: Well, it just seems a bit surprising you've got that much corrosion just from a glove. At least you fixed it.

MR. GRANTHAM: Are there any other questions on containment?

CHAIRMAN SIEBER: No, but I think it's an area where I need to and perhaps my colleagues need to ponder that because it is a complex design. It's not particularly amenable to a volumetric inspection. And since it's made out of carbon steel subject to corrosion because all of the essential elements of corrosion are present --

MEMBER BONACA: And the concern is that you don't want to go through corrosion before you find out.

CHAIRMAN SIEBER: Yes.

MEMBER BONACA: And so --

CHAIRMAN SIEBER: And this design, to my understanding, is unique in the industry.

MR. GRANTHAM: That is correct.

CHAIRMAN SIEBER: No other containment, Mark 1 containment, built like this. And so you can't draw on the experience of another plant particularly.

Okay. I think unless other members have questions --

MR. GRANTHAM: Okay. There was one other question about recirc piping replacement we're going to cover as part of this.

CHAIRMAN SIEBER: All right. You can do that.

MR. GRANTHAM: In the mid 1980s, we did replace the recirc risers. We did have some IDCC that went through. We had a number of welled overlays. And we did replace those with the one-piece no-weld construction riders.

CHAIRMAN SIEBER: Do you know what material the replacement risers were made from?

MR. GRANTHAM: Do you remember, Chris?

MR. MALLNER: This is Chris Mallner.

I think those replacement risers were a 316 ng nuclear braid.

MEMBER SHACK: So your recirculation headers, then, are still the original 304?

MR. GRANTHAM: That is correct.

MEMBER SHACK: Do you have overlays on them or IHSI, any kind of stress improvement, or it's just the 304 header?

MR. GRANTHAM: Do you want to address that?

MR. MALLNER: Again, this is Chris Mallner.

Nothing specific was done, as far as I can recall, with the headers. It was just basically riser replacements. I think they did some mechanical stress improvement, did some IHSI for the risers and around the nozzles.

MEMBER SHACK: Okay. So you still have augmented inspection, then, in the headers? You don't have two means of mitigation on the header welds from an 031 point of view?

MR. MALLNER: We still do the augmented inspections.

Again, Chris Mallner.

MEMBER SHACK: We might as well bring up the core shroud while we're here. The core shroud says it's stainless steel. Is it ordinary garden-variety stainless steel, 304, 316?

MR. GRANTHAM: It's 304 stainless steel.

MEMBER SHACK: So you don't need a

high-strength material to provide this integrity? It's not precipitation-hardened? I mean, it's 304.

MR. GRANTHAM: It's just straight 304 stainless steel.

MEMBER SHACK: Do you know what the stress load is on that? I mean, you're pushing this up near yield. Is it within an ASME kind of code stress limit?

MR. GRANTHAM: Chris, do you know?

MR. MALLNER: Garry Miller may want to address that.

MR. MILLER: My name is Garry Miller. I am the Manager of License Renewal. I was project manager when the shroud indications were diagnosed back in the early '90s.

Your question is were the loads across the shroud when the --

MEMBER SHACK: No, no. Across the tie rods.

MR. MILLER: Across the tie rods. Well, at low power, the actual weight of the structure above it is actually forcing down on that, the actual seam that actually had the majority of the indications in that the clamps go across.

As power is raised and steam pressure is raised inside the shroud, there becomes an upward force on it. So it changes during operation.

MEMBER SHACK: No. But there is a pre-load on those rods, which takes it to --

MR. MILLER: But we don't have rods. What we have got is one joint that, actually, there was a clamp across it where we EDMed holes through the shroud above and below that weld location and actually have bolted clamps across it and have changed. In essence, we have replaced that weld joint with a mechanical clamp across it, mechanical joint.

MEMBER SHACK: Oh, this is not one of these tie rod joints?

MR. MILLER: We were the first. And the design we have was one of a kind that preceded the rest of the tie rod designs.

MR. MEDOFF: This is Jim Medoff of the staff.

I asked an RAI to confirm that they did not replace the original clamps with tie rods and change their design. They confirmed that they still are using the C clamps and the repair design.

MEMBER SHACK: Okay. So this C clamp is bolted above and below the weld.

MR. MEDOFF: The C clamp should cover the

H-1 to 2 and 3 welds.

MEMBER SHACK: Welds.

MR. MEDOFF: That's correct.

MEMBER SHACK: Why?

MEMBER WALLIS: To react to a design by a carpenter.

MEMBER BONACA: I just have a question I want to ask just for information here. You know, we talk about the shroud and the problems you have with the shroud. That's operating experience.

When I was reading the application chapter 3, you know, under mechanical descriptions of the six individual groupings of passive components, for each one of them, for example, the reactor vessel and reactor coolant systems, you provide operating experience, a summary of it. And there I found a description of the steam dryer cracking that you had experienced or has been experienced actually be a sister plant, I mean, and the erosion components, but specifically you talk about flow orifices and pump casings in the CRD system.

There is no mention there of any other operating experience. Yet, throughout the application, I found a lot of examples, including the shroud, for example. That tells me that there is additional operating experience.

What am I missing there? You use words like as "This is the operating experience. No other unpredicted aging effects were found." What does it mean?

MR. GRANTHAM: Chris, do you want to take that?

MR. MALLNER: I'll take it. Again, this is Chris Mallner.

We do our operating experience review in order to determine whether or not there is a possibility that there is an aging effect that could be happening at our plants that our normal aging using our aging tools would not predict.

So if we review the operating experience and we find that the operating experience would have been predicted by the tools we're using in order to predict aging effects, we say that those things are the same.

MEMBER SHACK: So that's what we mean --

MR. MALLNER: What we're looking for in our operating experience is those things that would be outside the bounds of our aging tool and would only be predicted by operating experience.

MEMBER BONACA: So you really did not

experience, for example, erosion of components such as pump casings and CRDs?

MR. MALLNER: That's correct. That was a --

MEMBER BONACA: Sister plant. Okay.

MR. MALLNER: This is Chris Mallner again.

No. That was a plant-specific thing. We had gone in there and noticed there was some erosion of a pump casing. They did a nickel-based alloy overlay. We identified that from operating experience. And we applied a one-time inspection program to validate the efficacy of the repair.

MEMBER BONACA: Okay. Fair enough. Okay. I understand now.

MR. MIKE HEATH: We'll then return to operating history with Mr. Beller.

CHAIRMAN SIEBER: Okay.

C. OPERATING HISTORY

MR. BELLER: This is Lenny Beller.

Going back to operating history, unit 2 actually was licensed and began commercial operation first. Commercial operation on unit 2 began in November of 1995. And unit 1 followed in March of 1997. Current license expiration is September --

CHAIRMAN SIEBER: '77 and '75.

MR. BELLER: Thank you very much. '75 and '77. Current license expiration for unit 1 is September 2016 and unit 2 in December 2014.

Our operating license thermal power has changed over time. We were originally licensed to 2436 megawatts thermal. In the mid '90s, we had to take a stretch uprate of 5 percent to 105 percent of original licensed thermal power.

We were licensed. We received our license for that in November of 1996. It was a pressure increase power uprate. So we implemented it in the subsequent refueling outages. So we can do the plant modifications that would support that.

In May of 2002, we received a license for an extended power uprate. In our operating history there, after receiving the license, since it was a constant power uprate, we could proceed with increasing power through our start-up test program.

Unit 1 increased power to 113 percent of original rated in June of 2002 and then went to 120 percent in April of 2004. So we're just now completing our full first cycle, refuel cycle, at the full 120 percent.

MEMBER WALLIS: Did anything happen that was noteworthy after you went to high power?

MR. BELLER: We have some operating experience --

MEMBER WALLIS: The steam dryers worked quite okay?

MR. BELLER: That's correct. And we have a presentation that Mr. --

MEMBER WALLIS: Within the scope of license renewal?

MR. BELLER: That's correct.

MR. MIKE HEATH: Steam dryers are in the scope.

MEMBER WALLIS: Did you have to apply for containment over-pressure credit?

MR. GRANTHAM: Yes, we did.

MEMBER WALLIS: You did?

MR. GRANTHAM: That's correct.

MR. MIKE HEATH: We were a safety guide 1 plant with a zero. And we did apply and receive increased pressure.

MR. GRANTHAM: We were required 3.1 psig of over-pressure. We got credit for 5 psig. And we had --

MEMBER WALLIS: For quite a long time?

MR. GRANTHAM: Around 20-24 hours is what sticks in my mind.

MEMBER WALLIS: Around a day.

MR. GRANTHAM: Around a day.

MR. BELLER: Continuing on, unit 2 achieved 116 percent power in April of 2003 and 120 percent power in April of 2005. So we're coming up on the first year of unit 2 on 120 percent power.

Current plant status, unit 1 is --

MEMBER WALLIS: Your dryers are different design from Dresden and Quad Cities, are they?

MR. BELLER: Yes, that's correct.

MR. GRANTHAM: That's correct. We have the BWR slant hood dryer that has roughly a quarter. For a given load, it has around a quarter of the stresses of what you would encounter in the square dryer hood.

MR. BELLER: Unit 1 is currently in its 15th operational cycle. Both units did transition to a 24-month cycle in 1997. Currently unit 1 is at 100 percent rated thermal power. And we are going to enter a refuel outage on March 4th of this year.

Unit 2 is in operating cycle 17 and, again, transition to a 24-month cycle in '97. Unit 2 is also at 100 percent power. We do have one plant issue. We have a white performance indicator, NRC performance indicator, for unplanned power changes.

A. APPLICATION BACKGROUND

MR. MIKE HEATH: This is Mike Heath. I'll give you a little discussion, then, on our application background.

This application was submitted and prepared using the class of 2003 format. We used the 2001 versions of the standard review plan and GALL and the March 2001 version of NEI 95-10.

As we put this application together, we built the application essentially using plant calculations. The plant calculations are developed using plant procedures for calculation development. And we are fully compliant with our appendix B program at Brunswick.

D. SCOPING DISCUSSION

MR. MIKE HEATH: We did our scoping. We did scoping on a system basis, initially using the UFSAR or design basis documents, and our docketed correspondence. We then drill down to the component level using our quality clash review from our electronic database. That allowed us to scope right down to piece parts or two components for our systems.

We also did focus reviews for regulated --

MEMBER WALLIS: What I don't understand, I noticed that light bulbs are in scope. It doesn't refer to the shape of the drywell. But light bulbs are in scope? I was amazed to see something like that in the SER.

Light bulbs are a disposable item. Why would they be in scope?

MR. MIKE HEATH: I'm not sure.

MEMBER WALLIS: Maybe it's the staff that said this. So maybe I should ask them why light bulbs are in scope. It just seemed very strange to me that light bulbs --

MR. MIKE HEATH: I don't recall putting any light bulbs in, but --

MEMBER WALLIS: Okay. Well, it's in the SER, page --

MR. MIKE HEATH: If we had a non-safety-related system, for instance, that had a component that was mounted on the control board. And we would have brought that system in for the function of having that switch on the main control board. I would have to check on the light bulbs, though.

We did focus reviews for our regulated events and for the non-safety-impacting, safety-intended function. A couple of things that came into scope because of that were the non-safety-related steam dryers, which is based on industry OE for uprated plants, and our non-safety-related drain, which is based on plant-specific OE associated with some drain failures we had that impact the safety-related equipment.

MEMBER WALLIS: Does this also affect some of the service water, which is relied upon to cool things which are supposed to work during an accident but are not safety-related?

There are some heat exchangers and things that service water works on. Did you bring them into scope? Was that an example of something brought into scope because of a non-safety-related system affecting performance of safety-related?

MR. MIKE HEATH: Did you catch the question?

MEMBER WALLIS: Did any of the service water get brought into scope because of its effect on safety-related systems?

MR. LANE: This is Jeff Lane with Progress Energy.

We brought in fluid-containing systems in areas that had safety-related components. So to the extent that non-safety-related service water pipe was in a building that contained safety-related components, it was --

E. APPLICATION OF GALL

MR. MIKE HEATH: We addressed all of our ISGs 1 through 20. This application was submitted to the old GALL prior to the new GALL being approved.

Our aging management review, we used the 2003 table format. It's a nine-column table, which then allowed us to align our line items with GALL. We identified 34 aging management program. Of those, eight are new to the Brunswick plant. And five are considered plant-specific to Brunswick.

CHAIRMAN SIEBER: Before you leave this slide, you say steam dryers are in scope. And obviously you have had the equivalent of a 20 percent EPU. What has the performance of the steam dryers been under the increased power level? What examinations have you made to determine if there is cracking or an extension of preexisting cracking? What measurements have you taken for things such as vibration or unusual system responses that could indicate that there were problems occurring with your steam dryers?

MR. GRANTHAM: This is Mark Grantham again.

In the outage before we actually achieved our full 420 percent uprate, we did a full VT-1 external inspection of our steam dryers. That was in accordance with GE SIL 644, rev 1, which provide the inspection criteria as well as BWR VIP 139.

CHAIRMAN SIEBER: VT-1 is a standard visual, as opposed to an enhanced visual?

MR. GRANTHAM: That is correct. We did find some minor cracking existing that was typically IGSCC-type cracking, small.

CHAIRMAN SIEBER: Where?

MR. GRANTHAM: Six to eight-inch range. We did do some modifications to the dryer based on the recommendations of General Electric. That included increasing the weld size on our cover plate. We have a three-eighths-inch cover plate that had a quarter-inch weld.

The dryers that failed after uprate, the square hood dryers, had a thin, one-quarter-inch, cover plate. We beefed up the welds on our cover plate so that they would be three-eighths-inch. We also added a center gusset to provide stiffening to the outer hoods. We also increased the size of the tie bars on the top of the dryer. Again, those modifications were performed in March of 2004.

In April of last year -- this is one year of operating at the full 120 percent power -- we came down for a mid-cycle fuel bundle replacement outage to do a leaking fuel bundle.

At that time, we went in and did a VT-1 inspection of the dryer repairs as well as the indications that we had identified in the VT-1 inspection during the previous outage and found no further degradation. So after one year operating cycle at 120 percent, we didn't see any further degradation.

Now, we do plan to repeat those inspections. It will be, again, a full VT-1. It will be external during our refueling outage, which starts in March.

CHAIRMAN SIEBER: Do you have any instrumentation installed that would tell you if you had unusual or excessive vibrations coming from the steam dryer?

MR. GRANTHAM: No, we do not. As a point of reference, dryer loading is heavily influenced by steam line velocity. Steam line velocity is a major indication --

CHAIRMAN SIEBER: Obviously the diameter of the steam line.

MR. GRANTHAM: The Brunswick steam line velocity after power uprate was 146 feet per second.

CHAIRMAN SIEBER: Okay.

MR. GRANTHAM: As a relative value, the dryers that failed, the square hood dryers, those steam line velocities, were well in excess of 200 feet per second.

CHAIRMAN SIEBER: What's the diameter of your steam line?

MR. GRANTHAM: Twenty-four-inch?

MR. BELLER: Twenty-four-inch.

CHAIRMAN SIEBER: And you had four?

MR. BELLER: That's correct.

MR. GRANTHAM: That correct. But the key point is, even after uprate, our steam line velocities were still well in the middle of the BWR fleet. For example, our steam line velocities after uprate were well below the steam line velocities of the failed dryers before they uprated.

So from a vibration standpoint, given the velocities we have, we don't believe that's an issue. And, again, we have not instrumented those dryers.

CHAIRMAN SIEBER: And you have no instrumentation to tell you whether it's happening or not?

MR. GRANTHAM: That is correct. We are doing the monitoring recommended by SIL, 644, which, again, is looking at moisture carryover and looking at conditions in steam lines.

MEMBER BONACA: Have you experienced any equipment degradation or failures due to the power uprate?

MR. GRANTHAM: We have seen some vibration issues. We implemented our uprate in a two-phased approach. We did some mods, came up to around 113 percent power on unit 1, operated a cycle, did mods during the next cycle, and did the full uprate to 120 percent.

During that interim operating cycle, where we were not at full power, we did have some cycling of our turbine control valves. We were operating at a non-optimum point. We did have some failures of our EHC return lines that were connected to the control valve and due to that cycling and vibration.

Now, that's an industry OE issue. It's happened at non-uprate plants. We did replace those lines with a flex connection. We also have had some vibration issues on small socket well drain lines. Again, that's an industry OE issue. We had failures --

CHAIRMAN SIEBER: On what, the main steam system?

MR. GRANTHAM: This was actually around our feedwater heaters.

CHAIRMAN SIEBER: Okay.

MR. GRANTHAM: But that's an industry OE issue. We had failures on those lines before uprate. So did uprate cause it? We attribute it to uprate. And we went in and implemented some modifications to install a more fatigue-resistant well configuration for those socket wells.

CHAIRMAN SIEBER: But none of those are safety-related?

MR. GRANTHAM: That is --

CHAIRMAN SIEBER: None of them are in scope?

MR. MIKE HEATH: That is correct.

MEMBER BONACA: Unit 2? You said unit 2 had a white on plant power changes. I mean, what were the power changes related to?

MR. BELLER: The first power change occurred in April of 2005. We can bring a slide up on this so that you don't have to try to remember everything I say here.

In April of 2005, we had a reactor feed pump, too broad of a rector feed pump and peller that failed. And, as a result, we had to reduce power to

60 percent to take that pump out of service and facilitate repairs.

In June of 2005, unit 2, -- these are all on unit 2 -- we experienced some debris loading on one of our circ water intake pump traveling screens. And, as a result, the pump tripped. And the operating crew took a conservative action to reduce power to maintain a vacuum in its desired range.

August of 2005, we had a dual unit shutdown, another conservative action. We had questions on our differential protection of our diesel generators. And while we were resolving that issue, we did take the units out of service because it was a conservative action taken to declare the diesel generators inoperable.

MEMBER BONACA: None of these seem to be related to the power uprate.

MR. BELLER: November of 2005 we had three separate instances of leaks in our condenser tubes in the water boxes; actually, one water box, the 2A water box. We are still assessing that as to its applicability to uprate. We haven't had a chance to enter the water box yet. So we have select causes. But we haven't been able to validate our root cause yet.

And then in December of '05, one of our reactor recirc pumps tripped. We had a blown fuse in the voltage regulation circuit. We do have a supplemental inspection scheduled this month by the senior resident at the Harris plant.

CHAIRMAN SIEBER: Well, the uprate will give you increased exhaust steam flow from the turbine, --

MR. BELLER: That's correct.

CHAIRMAN SIEBER: -- which some licensees have experienced increased condenser tube vibration sometimes to the extent that the tubes actually touch one another and wear.

Can you tell me where you had tube failures in the condenser?

MR. GRANTHAM: This is Mark Grantham again.

CHAIRMAN SIEBER: That gives you a clue as to whether it's the exhaust velocity that is causing it or not.

MR. GRANTHAM: I guess if you look at the two units, we have had far more tube failures over the years on unit 2 than unit 1. The tube failures we have recently experienced, if you picture our two water boxes, they're up at the top corners of the tubes.

CHAIRMAN SIEBER: Closest to the turbine exhaust?

MR. GRANTHAM: That is correct.

CHAIRMAN SIEBER: You might want to think about staking those two.

MR. GRANTHAM: Well, we retubed our condenser in the mid '80s, and our tubes were pretty heavily staked at that time.

CHAIRMAN SIEBER: What kind of tubes do you have?

MR. GRANTHAM: They're titanium. And so, like Lenny said, during the outage, that will be a prime inspection point to go in and try to ascertain what is happening there.

As an interim measure, we have gone in and we have plugged the tubes along those periphery on the outside.

CHAIRMAN SIEBER: Well, that will change with inertia that can give you different vibration modes, which may be helpful.

MR. GRANTHAM: But right now we really need to get in and do an inspection to fully understand what is going on there.

CHAIRMAN SIEBER: Okay.

MR. MIKE HEATH: We're done with methodology. Any other questions on that? Well, let's take a few minutes to talk about our commitment-tracking process.

F. COMMITMENT PROCESS

MR. MIKE HEATH: Brunswick uses our corrective action program to track off of it. And the license renewal commitments are handled exactly the same way.

The license renewal, we develop an implementation plan for each of our commitments. And the implementation plan lists each thing that we have to do. So every procedure change, any new procedures, new PMs, PM revisions all are contained in those implementation plans.

And the actions that we are using to make those changes are tied back to the corrective action program assignment. Each of those actions has a due date. Each of those actions has an owner.

In addition, we're developing a program manual for license renewal for Brunswick. That manual will have every requirement to comply with those commitments. And we'll be using that to do periodic assessments to assure that everything is being completed in a timely fashion prior to the period of extended operation.

Any questions on commitments?

MEMBER MAYNARD: Your commitment-tracking program or your corrective action program, once you make a procedure or program change to meet your new license condition, what ensures that it doesn't get reversed later?

MR. BELLER: The commitment-tracking program is modeled on the NEI guidance. And if the procedure in its entirely is meant to meet the commitment, that will be stated in the purpose section. And then you'll reference the commitment in the reference section.

If it's a section of a procedure, we'll put an "R" in the left margin associated with that. And it will say "R-1," for instance. R-1 will point back to the reference where the commitment was made.

So not only would you have to do the 50.59. You have to go through the commitment change process, which asks a lot of the same questions on this that --

MEMBER MAYNARD: It is flagged where it would have to be evaluated before the change could be made?

MR. BELLER: That's correct.

MR. MIKE HEATH: That's correct.

Other questions on commitments?

(No response.)

MR. MIKE HEATH: Well, I would like to conclude, then. A few comments concerning the new audit process. We were not the first to go through the audit process, but we had been through the old audit process with our Robinson plant.

What we found with the new process is that it was extremely helpful to us to have the opportunity to have staff on site to talk to directly concerning their issues and concerns.

We were able to resolve these issues and concerns early on in the process, very early in the process. And we think as a direct result of that, the SER when it was issued was issued with no open items and no confirmatory items.

So we were very pleased with it. We're hoping it's working for you as well as we think it has been working for us. Are there any other questions for us?

MEMBER BONACA: I had some questions.

CHAIRMAN SIEBER: Go ahead.

MEMBER BONACA: I have a few questions. One, it was in excessive medium voltage cables, not environmentally qualified. You have a new program, right, for this cable?

MR. MIKE HEATH: Yes.

MEMBER BONACA: Now, one thing I noticed is that you do inspect manholes at least every two years --

MR. MIKE HEATH: Yes, sir.

MEMBER BONACA: -- to remove the water if you find it. Is it all you do or do you do --

MR. MIKE HEATH: A water mitigation

MEMBER BONACA: Yes. Do you have any initiative to prevent recurrence of accumulation of water?

MR. MIKE HEATH: What we're doing on water mitigation for our manholes is the manholes that we inspect are inspected based on our experience in water accumulation.

So the idea is we are inspecting those and finding that the water is below the cable. Then we're maintaining that inspection or increasing it or making it longer before finding, in fact, that it has impacted the cable. Then the inspection gets a sooner frequency. So the idea is to make sure that the water doesn't get up to the cables.

So, to my knowledge, I'm not sure exactly what the frequencies are, but most of these frequencies are much sooner than two years. And we'll adjust those depending on what we find.

MEMBER BONACA: Okay. But, I mean, your objective is not to have the cable wetted?

MR. MIKE HEATH: That's correct. Our objective is to have cable not be wetted when we find it during the inspection.

MEMBER BONACA: Okay. So you deal with it by frequency of the inspection?

MR. MIKE HEATH: That's correct.

MEMBER BONACA: You have no other means? Because this is part of your preventive action program. And so I thought that you may have some initiatives to prevent water from accessing the cable probably.

MR. MIKE HEATH: Well, we do do some things associated with that.

MEMBER BONACA: Okay.

MR. MIKE HEATH: For instance, there is a little catch bowl on the covers of the manholes. But what we're finding when we do go inspect them is the water is not up over the cables.

MR. BELLER: In addition, if we did find an unexpected condition, we would enter into the corrective action program, do an investigation, and corrective actions would come out to address. And it may be a PM frequency increase.

MEMBER BONACA: Another question I had was regarding the flow accelerator corrosion problem. There was a discussion in the ACRS regarding piping with super heated steam, essentially noting the problem. Okay?

But then there was a discussion of piping with greater than 99.5 percent quality but still some moisture there. And for it, you do not perform inspection for that.

MR. MIKE HEATH: Jeff?

MR. LANE: What we did was to evaluate that at the very low steam levels, we haven't seen a problem to that effect.

MEMBER BONACA: Okay.

MR. LANE: So we're making our program parameters as to the new revisions.

MEMBER BONACA: Which is okay to me, but you have, first of all, got some verification that you have no problem, right?

MR. LANE: Yes.

MEMBER BONACA: So you have measured some locations and must be looking at them?

MR. LANE: Yes.

MEMBER SHACK: Let me just go back. The new EPRI guidelines would have you include those within the scope of the program?

MR. LANE: This is Jeff Lane.

The new EPRI guidelines I believe say super heat conditions, basically. And the guidelines that we're operating under I believe are 99.5 percent. So that's the delta that we're talking --

MEMBER BONACA: I just had the curiosity more. I wasn't familiar. There is a discussion of TLAAs regarding the fuel pool girder, tension loss of prestress. What is the design basis for that system?

I mean, I was wondering. I understand you're measuring the tension in the cables and then provide correction action in case you have loss of tension.

I was wondering about fire. Is there a design basis dealing with fire issues below these girders or not? I was just curious.

MR. GRANTHAM: None that I'm aware of.

MEMBER BONACA: Okay. No. I understand that concrete is a pretty good protector of steel, but I just wondered if there was -- probably was not a factor other than the design basis, I guess.

MR. MIKE HEATH: Oh, no. We didn't address it.

MEMBER BONACA: All right. That was just a curiosity. And I'm done.

CHAIRMAN SIEBER: Okay. Anyone else have any questions that they would like to ask the applicant at this point?

(No response.)

CHAIRMAN SIEBER: And I presume you have concluded your presentation.

MR. BELLER: We have concluded our presentation. Thank you.

CHAIRMAN SIEBER: Okay. I think it's appropriate that we take a break. And I think a 15-minute break would be about right. If you could come back at 20 minutes to 3:00? At that time we'll listen to the staff's presentation.

(Whereupon, the foregoing matter went off the record at 2:25 p.m. and went back on the record at 2:40 p.m.)

CHAIRMAN SIEBER: We will come back to order.

MR. KUO: Mr. Chairman, S. K. Mitra, the project manager, will lead the staff presentation with assistance by Mr. Maurice Heath.

CHAIRMAN SIEBER: Thank you.

SER OVERVIEW

MR. MITRA: Good afternoon.

CHAIRMAN SIEBER: Good afternoon.

MR. MITRA: I am S. K. Mitra. I'm the project manager for Brunswick steam power electric plant units I and II license renewal application.

To my right is Mr. Maurice Heath. He is a project manager also. He helped me prepare the SER and issue it. And he will present the TLAA section of the presentation.

CHAIRMAN SIEBER: Okay.

MR. MITRA: I also have Mr. Caudle Julian, the lead inspector from region II, who will present the inspection done by region II. Mr. Greg Cranston. He was here. He will be here. He was the team leader for the audit. And if you have any questions, he can answer that. And also present in the audience are the technical reviewers who contributed to the SER to answer any question that may arise.

Next. These are the subjects which we will cover during the presentation. The LRA, the license renewal application, is submitted by letter dated October 18, 2004. And the applicant already described about their boiling water reactor, Mark I design containment.

The plant is located at the mouth of the Cape Fear River in the Brunswick County, North Carolina, two miles north of Southport, North Carolina. Unit 1 expires, license, on September 8, 2016; and unit 2, which was started earlier, December 27, 2014. And applicant requested an operating license extension for 20 years.

Each unit generates about 2,923 megawatt thermal, 1,007 megawatt electrical. That includes 20 percent extended power uprate. And, as applicant described before, the five percent power uprate was approved by NRC on November 1996. An additional 15 percent was extended on May 2002.

Again, I am emphasizing the steam dryer within the scope of license renewal. And applicant committed to review plant and industrial operating experience relevant to aging effects caused by operation at power uprate. The evaluation will be submitted to NRC review one year prior to the period of extended operation. And that's reflected on commitment number 31.

This commitment was made in response to ACRS letter of September 16, 2004 on license renewal application of Dresden/Quad Cities.

The SER issued on December 20, 2005. And it doesn't contain any open or confirmatory items. I stop right there. The reason no open or confirmatory items was not that easy on applicant. Staff and applicant had numerous dialogues. If you see, we had 174 RAIs via 4 letters. And we had 39 audit questions requiring supplements. And we had numerous dialogues by meeting face to face and conference call.

And I have to thank both sides. Applicant and the staff showed a lot of patience and understanding to resolve all the issues raised by RAIs and audit questions.

CHAIRMAN SIEBER: A hundred and seventy-four is compared to other previous applications, pretty small number.

MR. MITRA: It's a small number. And audit questions, we had 100 in total. And 39 need response under alternate information because there is a change. Compared to what recent count, it's very insignificant.

ACRS has three licensing conditions. And these are the usual licensing conditions under each of the previous applications.

MEMBER SHACK: The aging management programs and BWRs must be in a sense more consistent since they all kind of followed the VIP program. There is I would think a lot of standardization that may not be in the other --

MR. MITRA: If you are asking that question because the RAIs are smaller, it's not true because what I heard from other BWR plants that are being reviewed right now, the questions --

MEMBER SHACK: Are still --

MR. MITRA: Higher. So I have to assume the application was better than most other BWRs.

Through the review, three items that we brought into scope are switchyard breakers; service water intake structure fan, dampers, bird screen; and condensate storage tank piping credited for SBO. I will describe this while I go further in the slide.

The NRC review process is usual. We do scoping and screening methodology audit. We go. We went there to the plant to do consistency with GALL audits two times: AMPs, aging management program; and aging management reviews.

The technical staff, the portion that is not consistent with GALL, the technical staff did in-house safety review. And we had regional inspection, which contains scoping and screening inspection and aging management program inspection.

And Caudle will elaborate on that later on.

This is the time line we had when we went to the site. You see the GALL audits are done right in the beginning, within a couple of months, three months after the application and then scoping and screening methodology audit. And then we had last, but not the least, the regional inspections.

On section 2, the structural components subject to aging management review, we have section 2.1 had scoping and screening methodology. Staff audit and review concluded the applicant's methodology satisfies the rule pursuant to 10 CFR 54.4(a) and 10 CFR 54.21.

Section 2.2, "Plant Level Scoping Results," staff identified no omission of systems and structures within the scope of the license renewal as defined by 10 CFR 54.4 criterion.

A. SCOPING AND SCREENING RESULTS

MR. MITRA: Section 2.3, "Scoping and Screening Results of Mechanical Systems," as usual in other applications, we had reactor vessel, internals, reactor coolant system. We have engineered safety features. We have auxiliary systems. And we have steam and power conversion.

What is new is this is the first time

staff have reviewed balance of the plant scoping and screening review in a two-tiered process. The staff presented this concept to ACRS full committee on March 4th, 2005. And I guess they got the blessing and explained the review process at that time.

Two-tiered process, two-tier scoping review based on screening criteria of safety importance/risk significance, systems susceptible to common cause failure of redundant trains, operating experience indicating likely passive failures, and previous license renewal application review experience of omissions.

The tier 1 review actually has the screen and review the license renewal application and FSAR and identifies certain systems, samples certain systems for inspection. And we will cover that there are three systems that were referred to for inspections during the written inspection.

In tier 2 review, which is more detailed, they go through the boundary drawings, other licensing basis documents, such as plant, you know, relief request and all of this. And they look at, of course, the application in FSAR.

There are 62 mechanical systems. And out of that, 39 are the balance of the plant, most auxiliary and steam and power conversion systems. Out of that 39, 15 balance of the plant systems selected for tier 1 review. And 24 are selected for tier 2 review. The rest of 23 mechanical non-balance of the plant systems are RCS, engineered safety features, some auxiliary systems, continue to receive tier 2 review. And obviously electrical and structure receive tier 2 review.

MEMBER WALLIS: Now I've got a question about something here.

MR. MITRA: Okay.

MEMBER WALLIS: When you're figuring out what is in scope, just take an example. There is a heat exchanger for the fuel pool cooling system. It's got tubes in it. The heat is removed, and it goes into the reactor-building closed water cooling system.

The only thing that is in scope is the shell and access cover, channel head and access cover. So it looks as if what you are worried about is the outside of this heat exchanger. You don't want to leak into the environment. That's presumably because you don't want water from the fuel pool cooling system to go out into the building.

But doesn't it matter if it goes from that into the service water system and through the tubes?

And doesn't it matter if the heat isn't transferred? Why is only the shell in scope? Why isn't the internal function also in scope in some way?

MR. MITRA: My first crack will be the shell is in scope because it is giving you the boundary at the outside. And why it's not out inside of the shell is not I don't have the answer. Any of us --

MEMBER WALLIS: So you don't care if the water goes into the building, into reactor building closed cooling water system. It doesn't matter. But it does matter if it goes into the building. It just seems a bit odd to break it up that way. It says something about a fluid-retaining boundary. But the tubes also retain the fluid, don't they?

But, anyway, I just raise that because I am a little puzzled by how you decide what is and is not in scope. In some of these things, the condensate cooler tubes are in scope. And then the tubes are not in scope for this other heat exchanger. I'm so puzzled by how you decide when the tube is in a heat exchanger and scope and when they are not.

MR. MITRA: Bill Rogers will address the question.

MR. ROGERS: I'm Bill Rogers from Division of Engineering.

I did the scoping and screening methodology audit. I can't answer the particulars for that piece of equipment, but just in general, to determine whether the item would be in scope or not, it would have to fall into one of the three categories: (a)(1), (a)(2), or (a)(3). And that would be based on the intended function of the item.

If it had a safety-related function, it would be in scope for (a)(1). And if it was a non-safety-related item that supported the function of another safety-related system, it would be in scope for that purpose. But that's the beginning for the determination of whether it's in scope. I can't speak to the specific review of that component.

Does that help address your question?

MEMBER WALLIS: Is there something called a pressure-retaining boundary that uses a criterion, then?

MR. ROGERS: No.

MEMBER WALLIS: That's what comes up in the write-up. It talks about pressure-retaining boundaries. Well, maybe this is too complicated.

MR. KUO: The pressure-retaining boundary, Dr. Wallis, is one that actually advanced to the category (a)(1). That is the safety-related structure systems.

MEMBER WALLIS: What you really mean is a fluid-retaining boundary, isn't it? Pressure isn't something you retain. You retain the fluid and something that keeps the fluid from getting out into somewhere else. So that's why I wondered why tubes aren't also.

But, anyway, let's move on. I'm just puzzled by this.

CHAIRMAN SIEBER: Maybe I can add a little something to it. Being a safety-related component means that it mitigates one of the design basis accidents, of which loss of fuel pool cooling is not one.

Typically in a fuel pool cooler, the service water side of it is at a higher pressure than the pool water. So if the tubes fail, the water leaks into the pool, as opposed to the pool leaking out to the service water and then to the environment.

So from the standpoint of being able --

MEMBER WALLIS: That's not too good because the pool then overflows, then?

CHAIRMAN SIEBER: Yes. On the other hand, you know, that's an easier thing to control than trying to cool the pool and having the pool water escaping to the river. And that's why they designed it in that kind of a fashion.

So it's not unreasonable, at least in my way of thinking of things, to say that the fuel pool cooling heat exchanger is not safety-related because it doesn't relate to the design basis accidents.

On the other hand, it's important from the standpoint of preserving the service water system, which is used for other mitigating equipment. And you can still perform the function, even if some tubes leak. You know, it takes a long time to heat up the pool anyway.

MEMBER BONACA: The licensee, is this a correct evaluation that Mr. Sieber made?

MR. LANE: I'm Jeff Lane with Progress Energy.

The fuel pool heat exchangers are in scope for special interaction. RBCCW, our closed cycle cooling water system, doesn't perform any safety-related cooling functions at Brunswick. So we're concerned with the fuel pool heat exchangers basically not leaking into the reactor building environments.

Should an RBCCW tube leak, interaction

between RBCCW and fuel pool cooling would not cause an adverse interaction to the environs. It would be something we would have to address in the course of plant operation but not an issue that would affect license renewal scoping.

CHAIRMAN SIEBER: One cause of an accident or preventive mitigation of a design accident, --

MR. LANE: Right.

CHAIRMAN SIEBER: -- design basis accident.

MEMBER BONACA: You get more than a passing grade.

CHAIRMAN SIEBER: Pardon?

MEMBER BONACA: You deserve more than a passing grade. You are correct.

CHAIRMAN SIEBER: I'm going to write that down. Okay.

MR. MITRA: We mentioned before that condensate storage tank piping credited for SBO brought into the scope. There's some pipes that were not in scope. The condensate storage tank was in scope, but the piping was not. And due to mechanical system review, there are some RAIs that brought into the piping in scope.

And also service water intake structure

fan, the bird screen, and damper housings are brought into scope. And this is also through a RAI process.

MEMBER WALLIS: A fan is in scope?

CHAIRMAN SIEBER: Yes.

MR. MITRA: It is.

MEMBER WALLIS: What has that got to do with safety?

CHAIRMAN SIEBER: It's service water safety-related.

MR. MITRA: The service water infrastructure is in scope. So that's why the fan, the screen, and the damper housing are brought into scope.

MEMBER WALLIS: Well, okay.

CHAIRMAN SIEBER: It is better to be in scope than out of scope.

MR. MITRA: This is 2.4, scoping and screening of structures. And there are two types of structures. One is containment. Another is class I and in-scope structures and buildings. There are 15 of them.

Section 2.5 has scoping and screening as a result of electrical and instrumentation control I&C systems. And the guidance contained in 95-10, appendix B was used to develop a list of electrical

I&C community groups.

Dr. Wallis, your question about the light bulb was in that NEI 95-10, appendix B had listed it as scope, but it's screened out because of its active components. So there is no aging management review on that.

MEMBER WALLIS: Oh, it is an active component?

CHAIRMAN SIEBER: Yes.

MR. MITRA: The switchyard breakers at 230 kv gas-filled power circuit breakers, respresent the first breakers for the SBO recovery path that are brought into scope of the license renewal process.

In summary, the applicant scoping methodology meets requirements of 10 CFR part 52. The scoping and screening results as amended included all system structural components within the scope of license renewal and subject to aging management review.

And now I give the floor to Caudle Julian for licensing and inspection.

CHAIRMAN SIEBER: Welcome.

MR. JULIAN: Hello. Thank you.

<u>B. ONSITE INSPECTION RESULTS</u>

MR. JULIAN: My name is Caudle Julian from

NRC region II in Atlanta. And I have led the team inspections for license renewal for all of the region II plants, here today to talk about the Brunswick inspection that we did last June.

The slide you see up there now lists the topics we are going to talk about. If we can click over to the next one? It's one you have seen before, to tell you again that we have a manual chapter, 25-16, and an inspection procedure, 710.02, that we follow for these inspections. We develop a site-specific inspection plan for each one. And they are scheduled to support NRR's review schedule.

We have two portions to our inspection, scoping and screening inspection, area, which has the objective to confirm that the applicant has brought the right stuff into scope. And S. K. has portrayed it here as the first half of the inspection was that. It was probably less than half of a week of effort this time.

We were using our new procedure, where we have revised 710.02 to reduce the amount of resources that we put on scoping and screening. We have talked about that before. And we will focus primarily on (a)(2) situations, non-safety equipment that can affect safety.

We took from NRR's request to look at three of their tier I systems that they had questions about. And you can see they are non-safety systems: heat tracing, moisture separator reheater drains and reheat and heater drains and miscellaneous vents and drains. And those systems are, of course, out in the balance of plant. And one would not think that that would be a safety-related function there.

We went out with the applicant people and walked those systems down and concluded that they had done a good job and that those systems were very conservatively brought into scope.

MEMBER WALLIS: Why would you pick those? I would think you would look at things like bulges on the containment floor or something. These seem to be so far removed from safety systems.

MR. JULIAN: I agree with you. Those selections were made by NRR as ones for us to look at.

MR. MITRA: As I described before, -- this is S. K. Mitra again -- this is a process that followed in tier I and tier II, two tiers of review of the balance of the plant system. And maybe Mr. Chang can explain why he chose this system particularly.

DR. CHANG: We used a two-tiered review process to deal with the balance of planning systems, which it has 29 of them. We will put our focus to have detailed review on the tier II review and grouping that 15 out of 39 systems into tier I.

Among those 15 systems, I looked at it. I pick up three out of 15 because those systems, most of those systems involve the (a)(2), which the application by itself doesn't tell me much. And even if I look at the drawings, it's still not enough information for me to make a determination.

However, if we go to either very detailed review of all those systems, we think we would rather have our focus and attention, resource put on the rest of the more important systems.

So among those 15 less important systems, our review process, review application description, the FSAR descriptions, but we are not able to go into the detailed drawings.

We ask the inspecting teams to go in there, look at the systems, look at the drawings, look at the calculations by self so that they would be able to look at the methodologies of doing this, true systems. And once we have the three systems group being scoped properly, we would be able to have confidence on those 15 systems, which have the similar way of doing a true process. So that's how we draw the three systems that are necessarily important. Actually, they are not very important. It's on the first screening, two-tiered screening, process.

MR. JULIAN: So his real answer is there were none better to select from. The group that we had to look at were out on the --

MEMBER WALLIS: But if you were to find something wrong with the heat tracing systems, that wouldn't have prevented license renewal, would it? I mean, it's not an important issue.

MR. JULIAN: No. So we were looking at ones here that they had brought into scope. We were looking to see that they had identified that you can't tell about --

MEMBER WALLIS: You're testing their approach and their methods and so on. That's what you're doing.

MR. JULIAN: Yes. We're actually going out and looking at the hardware.

MR. GILLESPIE: Frank Gillespie.

Let me say it a different way. We don't want to inspect what we already know is in. What they're doing is testing what the licensee has not included to see if it should have been in. So, in fact, if the inspectors are actually looking at an important system, we have done something wrong because that means the licensee left an important obvious system out of scope.

So what we're really testing here is the (a) over (2) methodologies in the fringe systems. I mean, that's more simply what we're really doing.

So you're actually looking for what is not included, as opposed to inspecting what they have already volunteered, is going to be managed.

MR. JULIAN: And Brunswick was rather conservative, I think. There were not many borderline cases that we had big disputes about in Brunswick.

Moving on, the second half of the inspection was the aging management program. The objective is confirmed that the existing AMPs are managing current age-related degradation and that they have -- we found that they had established a very comprehensive implementation plan in their plant acquisition request system -- that was talked about as a corrective action program earlier -- to track the committed future actions.

We found in our inspection a few examples where actions committed in aging management program description documents were not yet into the implementation plan.

These were only two or three examples. And we think the issue was that they were not yet. They had been recently committed to by NRR, but when these were pointed out, the applicant promptly made changes to the documents and included the comments that we have had.

In our walk around Brunswick -- and we did one look-see inside the drywell during a refueling outage -- we thought that the material condition of the plant was being adequately maintained. The documentation that we saw was a very good quality and was supported by a comprehensive computer database controlling equipment that we spoke of earlier.

One other issue that we normally talk about here is what is the current performance of the plant with respect to the reactor oversight program. Brunswick unit 1 you can see we have here the third quarter performance indicators that are posted on our Web site.

I believe the fourth quarter is just any day now we'll be coming out fourth quarter of 2005. Look to the next, please. There is nothing remarkable here, of course. Both of these are green. As the applicant has described to you, they had a bad run of luck in 2005 and had numerous power reductions. And that performance indicator is going to go white on unit 2 in the new data that is coming up on our Web site here in the very near future.

The criteria is the number of power reductions below 80 percent unplanned. And if you have things like condenser tube links, these kind of things happen but pose no particular negative light on the capability of performance to the operators and so on in the plant. It's just equipment problems that happen to them that put them in these circumstances. And that really --

CHAIRMAN SIEBER: It doesn't reflect on the performance of operators. On the other hand, it may reflect somewhat on the condition of the plant.

MR. JULIAN: Yes.

CHAIRMAN SIEBER: That's why it's a performance indicator.

MR. JULIAN: Yes. Well, that concludes what I have to say. Do you have any questions?

(No response.)

MR. JULIAN: Thank you.

CHAIRMAN SIEBER: Thank you, Caudle.

<u>AGING MANAGEMENT PROGRAM REVIEW AND AUDITS</u>

MR. MITRA: We'll go ahead and start section 3, "Aging Management Review Results." We have the usual internal reactor coolant system. And you see a separate feature of the system, steam and power conversion system, containment structure, and component support and electrical.

The total, we have a management program of 34. Only nine are consistent with GALL. Consisting of GALL with deviations is 20. And plant-specific are five.

The example we have of audits and built-in findings in the audit times, the Brunswick stimulator plant recent form ISI program was revised according to the EPRI topical report ER 112.657, which is not consistent with GALL, really.

ISI does not recognize the changes recommended by the EPRI report. As a result, the applicant revised the upsert to include pruritic, volumetric, surface, and visual examination of the component which is consistent with GALL. They actually according to the EPRI report, took that out. So we included that little bit during the audit process, and they put it in there, actually, again.

The second one bullet is originally --

MEMBER SHACK: Let me understand. When they go to a risk-informed ISI program, that is reviewed by the staff and approved, right?

MR. MITRA: Apparently this is a topical report here. 112657 was a recent report. And the applicant thought that they can follow that without going through the NRC's review.

But the staff found that, and they said it's not being -- you know, the staff did not really recognize that EPRI report. And they go according to the consistent. As in the GALL, it's the volumetric and the surface and visual examination was included in GALL. And according to the EPRI report, they just took that out.

MEMBER BONACA: I thought this was only pertaining to small bore piping. There's an exception here of moving from ISI. I mean, I thought the logic was, as in GALL, that you're looking for susceptible locations as a lead indication for use. Therefore, you don't want to have a risk-informed approach.

But I thought that this was really pertaining to small bore piping.

MR. MITRA: I think it's not just the small bore piping.

MEMBER BONACA: Okay.

MR. MITRA: It's for everything else.

Greg, do you have something to add on that? Greg Cranston is our leader.

MR. CRANSTON: My name is Greg Cranston. The concern we have is we don't want the risk-informed ISI to be a basis for elimination of inspections. So it covers primarily the small bore but other areas, too. It's kind of like really for questions, things like that that we don't want them to cite those as reasons now. So that's how we cover it.

MEMBER BONACA: Pertaining only to small bore piping or all piping?

MR. CRANSTON: I know it pertains to small bore piping. I'm not sure if it extends beyond that.

MEMBER BONACA: The issue has always been the small piping. I mean, that's my understanding.

MR. MEDOFF: This is Jim Medoff of the Division of Component Integrity. We're the division responsible for granting relief requests under 50.55(a).

Licensees are required to get any risk-informed ISI programs submitted in a relief request and approved by the staff. For small bore pipe, we in the past have come up with -- they are exempted by the code, but we still need one of them managed for license renewal. So we came up with a risk-informed approach to select a sampling of small bore pipe.

And we're talking about small bore pipe with full penetration but for inspection. And they can use a risk-informed approach to pick the locations that they're going to select on the sampling basis.

So the risk-informed ISIs are only granted normally for the ten-year intervals. And they reapply once they're coming up for the next interval.

MEMBER BONACA: So what you're saying is that you're looking for susceptible locations. However, you're using a risk-informed approach?

MR. MEDOFF: Yes, meaning --

MEMBER BONACA: How do you do that?

MR. MEDOFF: It's based on, I think the approach, if I'm not mistaken, is based on, those locations that would impact the PRA most and have the most susceptibility for failure, a combination of the two.

MEMBER BONACA: To me it is a change from what I -- maybe I am just behind the time, but --

MR. MEDOFF: Actually, this has been incorporated into the revision, into the new small bore AMP for the revised GALL.

MEMBER BONACA: So I'll have to do a little bit better. Thank you.

MR. MITRA: The second bullet is the

applicant already committed to inspect and clean RHR emergency diesel generator jacket water heat exchanger prior to creating an exchanging operation.

This is in lieu of any test result of the heat transfer capability of heat exchanger as recommended by GALL. So they modified the open cycle cooling water heating management program to include performance testing of heat transfer capability.

There are a couple of more examples. They originally committed to inspect buried piping only during opportunistic inspection. And due to all the questions, they modified. And they have agreed to perform periodic inspection, at least once every ten years. But opportunity inspection can qualify for periodic inspection.

And also the inspection and coated piping has to be done by the coating inspector. Also, that they have put in commitment number 13.

MEMBER BONACA: So now they're consistent with GALL?

MR. MITRA: Yes, they are consistent with GALL. And that's the new GALL.

MEMBER BONACA: The new GALL, yes.

MR. MITRA: The new GALL.

MEMBER BONACA: Yes.

MR. MITRA: And the structural monitoring program was not originally consistent with GALL. The modified aging management program, the commitment number 16 said they include the inspection of so much portion of the service water infrastructures on a frequency not to exceed 5 years and specific in-well groundwater monitoring inspection frequency of concrete structures and specific inspection frequency for service water intake structure and intake can all not exceed 5 years.

MEMBER WALLIS: Five years is a strange measure of frequency.

MR. MITRA: Well, I really don't know where the five years come from.

MEMBER WALLIS: I understand what you mean, but it is a sort of tortuous way to put it. Frequency is so much per year or something, isn't it?

DR. CHANG: This is Ken Chang.

What it really means is he inspected at least once every five years. It doesn't mean frequency.

MEMBER WALLIS: It doesn't make sense.

DR. CHANG: The word "frequency" is being used in a different meaning. I agree.

MR. MITRA: Reactor vessel internal and

reactor coolant system have five plant-specific systems, which is reactor vessel and internal neutral monitoring system, reactor manual control system, control rod hydraulic system, drive hydraulic system, and the reactor coolant recirculation system.

Reactor vessel internal structure integrity program, the program is a plant-specific aging management program. The inspections, the program inspections, are based on the augmented inspection recommended by the BWRVIP. And the applicant committed to, which I think is commitment number 22, define which BWRVIP reports are included in the scope of the program, additional specific augmented activities that will be taken by the applicant. So if you see commitment number 22, there's a list of all the BWRVIP programs that will be included, almost a one full list.

Reactor vessel surveillance program, the program monitors for the impact of neutron irradiation on the fracture toughness properties of RV material. The program is based on the integrated surveillance program criteria, BWRVIP-78 and 86.

The applicant is committed to enhance the program to include conformance with updated integrated surveillance program criteria, VIP-116, BWRVIP, once approved by NRC. And I know that it is being submitted to NRC and it's being reviewed now, BWRVIP-116.

Engineered safety features, they obtain plant-specific systems. And in response to one of the RAIs, the applicant committed to manage the loss of material in tracking and small bore class I piping-treated water, including steam and internal environment, using one-time inspection.

Auxiliary system, 34 plant-specific systems. Applicant committed to add preventative maintenance program, routine sampling and analysis to address corrosion concern related to potential water intrusion into lubricating oil in the service water pump motor cooler coils and the emergency diesel engines lube oil system. That's commitment number 24.

Additionally, applicant committed to add to one-time inspection program at least one of the four emergency diesel engine sumps and at least one of the ten service water pump lubricating oil cooling coils for corrosion products and evidence of moisture. That's commitment number 11. And this is also in response to RAI.

MEMBER WALLIS: So one out of 10 is a good enough sample?

MR. MITRA: Richard? Anybody else in there can answer that, the sampling size? No? Well, we can take this --

MEMBER WALLIS: You can conclude that if no moisture leaked into one of these, then it's likely it didn't leak into any of the other ones?

MR. MITRA: I don't --

MEMBER WALLIS: I don't think it's a big issue. I just wonder, though, why one is enough.

MR. MITRA: We can take this action. And we will find out. If applicant has any answer for this, why one in ten is --

MR. LANE: This is Jeff Lang with Progress Energy.

As far as one in ten, I don't recall a specific basis, but I can say that any time that we change lube oil and empty the sumps, we do an inspection. In actuality, there will be many more inspections, and it's done. We will document one of them for the propose of license renewal.

MEMBER WALLIS: That makes more sense.

MR. MITRA: Do you need further clarification?

MEMBER WALLIS: No. That's okay. If they're doing it all the time, that's all right.

MR. MITRA: Okay. The steam and power conversion systems, they have 13 plant-specific systems. The applicant's AMR result for titanium components in a raw water environment was an issue requiring additional information.

The applicant clarified that the titanium in a raw water environment at a temperature less than 160 degrees Fahrenheit does not exhibit aging effects. The titanium tubes in a raw water environment are at a temperature less than 160 degrees Fahrenheit.

MEMBER WALLIS: What is raw water? I understand what pure water is.

CHAIRMAN SIEBER: Raw water means comes striaght from the river.

MR. MITRA: It's raw. Raw means it's unpurified water.

CHAIRMAN SIEBER: It comes out of the river.

MR. MITRA: It comes out of the river.

CHAIRMAN SIEBER: Yes.

MEMBER WALLIS: So you don't really know what is in it. It could be anything.

CHAIRMAN SIEBER: You'll find out if you drink it.

MEMBER WALLIS: Titanium doesn't react

with anything.

MR. MITRA: Containment, structure, and component supports. As I said, containment and other 15 structures and buildings there. Brunswick steam electric plant credits ASME section XI, subsection IWE and 10 CFR part 50, appendix J for management for a drywell liner. And I think the applicant went through detail on that.

Both IWE and appendix J require 100 percent inspection per period. There are three periods per interval, and each interval is ten years. And the 100 percent inspection is for the accessible area, but if corrosion is noticed during inspection, 10 CFR 50.55(a) is demanded to inspect the corresponding non-accessible area also.

Each period is 3.3 years. If you divide 10 by 3, it's 3.3. The Brunswick outage they have every 24 months. The BSAP, the Brunswick plant, the partial inspection in each outage, they do the partial in each outage, but complete, 100 percent they do in 2 outages. So as a result of the fourth outage, which is after 8 years, they are required to do 100 percent inspection the last.

This is inaccessible concrete in acceptable range for non-aggressive environment, inaccessible concrete more than 5.5 pH and less than 500 ppm for chloride and less than 1,500 ppm for sulfates. And groundwater phosphate is .12 ppm. As a result, we concluded that below-grade environment is quite non-aggressive.

The electrical and I and C program, component/commodities subject to AMR, there are six of them: the Non-EQ insulated cables and connections, phase bus, non-EQ electrical and I and C penetration assembly, high-voltage insulators, switchyard bus, and transmission conductors.

In response to RAI, applicant committed to add preventive maintenance program and periodic inspection of high-voltage insulators for water beading on silicone coating and for age-related degradation. That is commitment number 24.

And in another RAI, applicant committed to include in the phase bus aging management program inspecting the interior condition of the bus enclosure for foreign debris, excessive dust build-up, and evidence of water inclusion, and use a structural monitoring program to inspect the external surface of the phase bus housing, checking the accessible and inaccessible phase bus voltage connection by thermography on a ten-year frequency while bus is energized and loaded. That is commitment number 25.

Now we will go to the TLAAs. And my colleague Maurice Heath will address the TLAA portion.

TIME-LIMITED AGING ANALYSES NRR

MR. MAURICE HEATH: Good afternoon. Like he said, my name is Maurice Heath. And I will be doing section 4, time-limited aging analyses overview.

Section 4.1, we have identification of TLAAs. And that is based on by definition 10 CFR 54.3. Section 4.2 through 4.7 are the six main categories for the TLAAs, and I will be touching each one of them in the following slides. One note I would like to add is, if you notice, 4.5, concrete containment, tendon prestress, is not applicable to Brunswick.

For section 4.2, "Reactor Vessel Neutron Embrittlement," there were ten TLAAs identified. If you notice, the last bullet, "Reactor Vessel Thermal Shock Reflood Analysis," was added in response to a staff's RAI.

MEMBER WALLIS: Just wait a second.

(Pause.)

MEMBER WALLIS: Okay. Go ahead.

MR. MAURICE HEATH: Now I want to highlight for section 4.2 two important analyses that were done by the staff or by the applicant and verified by the staff. The first one is on the reactor vessel, "Upper Shelf Energy," and "Equivalent Margins Analyses."

Now, the applicant, what they used was from the guidelines of the BWRVIP-74. It established acceptance criterion. And, if you notice, we have their calculations here. And also the staff performed independent calculations to verify the applicant's conclusions. And the values were all under the acceptance criterion.

MEMBER WALLIS: What time are these values for? Is this for a certain time in the history of the plant? This is after so many years or something?

MR. MAURICE HEATH: Yes.

MR. MITRA: Yes.

MEMBER WALLIS: And this is -- what is it, 56 equivalent years or something?

MR. MAURICE HEATH: Fifty-four.

MEMBER WALLIS: Fifty-four?

MR. MAURICE HEATH: Fifty-four.

MEMBER WALLIS: This is the end of the new license period. Is that what it is?

MR. MAURICE HEATH: Yes.

MEMBER WALLIS: Well, I'm glad you have a table. When I read the text, I couldn't figure out if they were meeting criteria or not. There seemed to be such a lot of discussion going on. I couldn't tell. I mean, there were different numbers that appeared at various places in the text. I couldn't tell whether they were meeting the criteria.

Now you've made it clearer by having a table. Did I miss something? Was this table in the text or --

MR. MAURICE HEATH: Was it in the SER?

MEMBER WALLIS: Yes.

MR. MITRA: No.

MR. MAURICE HEATH: No, it was not.

CHAIRMAN SIEBER: A picture is worth 1,000 words.

MEMBER WALLIS: Yes.

MR. MAURICE HEATH: Did you have any more questions?

CHAIRMAN SIEBER: It seems to me that these vessels have a lot of margin.

MR. MAURICE HEATH: Yes. Conservative. Yes, they are.

MEMBER WALLIS: Well, this is one of these things. Are you going to talk about this? The next one is the RTndt.

MR. MAURICE HEATH: Yes. Yes. Now, this is reactor vessel circumferential weld and axial weld, the probability failure analysis. And the guidelines used for the circ welds and axial welds were BWRVIP-05. What it was was the mean RTndt acceptance for probablistic fracture mechanics and BWRs.

MEMBER WALLIS: Where does the Charpy value come into all of this? Is that what the -- these foot pounds of Charpy value, are they part of this somewhere?

MR. MAURICE HEATH: Jim may have to address that.

MEMBER WALLIS: They are also part of this material.

MR. MEDOFF: Right. This is Jim Medoff of the staff. I was the reviewer for the neutron embrittlement TLAAs.

MEMBER WALLIS: The numbers in the text seem to have nothing to do with this.

MR. MEDOFF: If you're talking --

MEMBER WALLIS: It's a different thing, isn't it, from the foot pounds and the Charpy values?

MR. MAURICE HEATH: Are you referring to the previous slide?

MEMBER WALLIS: Well, this isn't my field, but I was trying to figure out what was going on. I had all of these numbers of Charpy values, 45, 30, everywhere, 45, 57.4 or something, no indication of whether or not they met a criterion or what the criterion was? That's what I was missing.

MR. MEDOFF: This is Jim Medoff of the staff. The requirements are for upper shelf energy, but the BWR performed some generic equivalent margins analyses for all of the boiling water reactors in the fleet. And that's what the fleet is currently using.

There is one plant-specific equivalent margins analysis for the reactor vessel nozzle forging Brunswick is using because I had performed that review in I think it was like 1998 for them.

MEMBER WALLIS: So that's the same thing as the upper shelf energy?

MR. MEDOFF: Yes. Well, it's to prove that if they go below the 50-foot pound requirement at 10 CFR part 50, appendix G, that they would still have acceptable safety margins and upper shelf energy.

For the VIP documents, they valued different types of reactor vessel materials and base their equivalent margins analyses based on the --

MEMBER WALLIS: So these numbers are foot pounds, these numbers we see here?

MR. MEDOFF: Yes.

MEMBER WALLIS: From the fluence, right?

MR. MEDOFF: For the BWRVIP-74A, those are in percent drop in foot pounds and allowable percent drop in foot pounds for a group of materials. So for the limiting plate, it's based on the assessment of BWR plates and --

MEMBER WALLIS: Is the SER complete? I mean, I had a lot of trouble reading the SER to figure out what all of these numbers had to do with some criterion. If you could make it clearer in some way in the SER, it would help a lot.

I couldn't figure out, such a long discussion that I couldn't figure out from a table or something else whether all of these numbers, Charpy values, which don't look like the numbers in this table, meet some criterion or not.

MR. MITRA: We might take action to include this table in the SER.

MR. MEDOFF: Those numbers are pulled out from the SER.

MR. MITRA: Yes, but we don't have the table in the --

MEMBER WALLIS: It says something should exceed 50 foot pounds or is it supposed to be less than or more than? It says, "It should exceed 50 foot pounds." Is that right?

MR. MEDOFF: No. In the SER, it clearly clarifies what the requirements are in appendix G and what you're supposed to do if you fall below that. I have a regulatory base --

MEMBER WALLIS: It should exceed 50 foot pounds. Is that right?

MR. MEDOFF: Right. But if you fall below 50 foot pounds, what the rule requires you to do is do an equivalent margins analysis to demonstrate acceptable levels of upper shelf energy.

MEMBER WALLIS: Which seems to be much lower values.

MR. MEDOFF: Right. It would be lower than 50 foot pounds at the end of the extended --

MEMBER WALLIS: A lot lower, right? A lot lower? It's talking about 29, 30, 35, something. I just don't understand why it's all okay.

MR. MEDOFF: The 50 foot pound value is based on linear-elastic fracture mechanics. Once you fall below it, there are alternative fracture toughness assessments, specifically elastic plastic fracture mechanics, evaluations that they can use to show equivalent safety margin.

MEMBER WALLIS: And it's so arcane that I can't understand it.

MR. MEDOFF: The materials aren't here.

MEMBER SHACK: Well, I mean, you have to go through the fracture mechanics analysis, you know, but you postulate your big flaw and then you demonstrate that you, in fact, can sustain that. But it's sort of not intuitively obvious.

MEMBER WALLIS: That's right. It wasn't clear by what criterion the staff accepted these values that they came up with.

MR. MEDOFF: It should be in the SE, but I can point it out to you or we can revise the SE to make it clearer.

MEMBER WALLIS: Maybe you can make it clearer somehow. So that is quite different from this table we're looking at here. This is something else. And this quarter, the RTndt, what's that?

MR. MEDOFF: The RTndt, the boilers have submitted during the current term certain leave requests to eliminate certain inspections of their circumferential wells in their reactor vessel. They're based on probablistic fracture mechanics assessments that were developed by the BWRVIP, which were documented in the BWRVIP-05 report.

The staff reviewed that report and improved the probablistic fracture mechanics methods for the fleet and came up with limiting probability of failure values for both the circumferential welds and axial welds in the reactor vessel. And then they developed corresponding adjusted reference temperatures, maximum adjusted reference temperatures, for the vessel materials that would correspond to those probabilities of failure.

MEMBER WALLIS: Your conclusion is that they meet the --

MR. MEDOFF: As long as they're --

MEMBER WALLIS: -- correspondence with a big margin.

MEMBER SHACK: Again, the upper shelf is sort of toughness at high temperature. The RTndt is initiation embrittlement, just like the --

CHAIRMAN SIEBER: Brittle fracture, yes.

MEMBER SHACK: So they're looking at both ends of it and meeting it.

MEMBER BONACA: This is the first time I've seen negative --

MR. MEDOFF: The probability of --

MEMBER WALLIS: Okay. I think it just needs to be clearer in the document.

MR. MEDOFF: Well, we'll go through it.

MR. MAURICE HEATH: All right. We'll go on. Section 4.3, "Metal Fatigue." What I wanted to do is just highlight one of the TLAAs: reactor coolant environment on fatigue life of components and piping. Due to the staff's review, the applicant enhanced the fatigue-monitoring program to monitor fatigue for each of the six locations identified in NUREG 62.60. That's applicable to older GE plants and considering reactor water environmental effects.

The applicant performed a refined fatigue analysis based on data collection from cycle evaluation module and finite element analysis from fatigue-monitoring program to show CUF, the cumulative usage factor, will remain below the ASME code limiting value.

The staff found applicant's assessment acceptable in accordance with 10 CFR 54.21(c)(1)(ii).

MEMBER SHACK: Just clarify for me, is this a requirement in the new GALL that they do this now finally or is this still something you negotiate on a case-by-case basis?

DR. CHANG: Ken Chang on the staff.

In the new GALL, it is clearly stated the 6260 -- normally it's 6 or 7 locations -- is at a minimum. In establishing those six locations, safety has been taken into consideration. So these locations are of safety importance. You don't take like a pressurizer support skirt into consideration. Those are of no safety significance.

And also this is the minimum, six or seven locations. Normally applicants can select more than those locations. In this plant, it did select more locations for monitoring. It could be up to 11.

So originally they have five locations. And due to the audit, the auditing recommended and requested that, hey, explain why you are using like five of your locations and the GALL recommended, 6260 recommended, six locations everybody knows.

The applicant agreed to include in their monitoring program, fatigue monitoring program, all the 6260 locations. Some of them may be the same as the five they originally monitored, so up to 11 but could be as minimum as 6.

MR. GILLESPIE: But, Ken, Dr. Shack asked a question. Is this now in GALL?

DR. CHANG: It is in GALL.

MR. GILLESPIE: I just wanted to make sure that no, we're not negotiating this separately every time, which is why you are seeing fewer RAIs and hopefully you will see fewer in the future.

CHAIRMAN SIEBER: The answer is yes.

MEMBER WALLIS: Now, is this fatigue due to pressurizing and depressurizing the system? Is that what it is or is it fatigue due to something shaking or is it fatigue due to thermal changes or --

DR. CHANG: Mostly thermal.

MEMBER WALLIS: Mostly thermal. It's not just the pressurizing --

CHAIRMAN SIEBER: Part of shutdown.

DR. CHANG: Now, this fatigue analysis is in the ASME. Currently we call ASME fatigue analysis.

MEMBER WALLIS: Like flows in and out of the pressurized --

DR. CHANG: Oh, yes. Those are the PWR cases.

MEMBER WALLIS: Yes.

DR. CHANG: In the BWR cases, you probably are looking at the feedwater nozzles. Those are equivalent to the PWR's pressure research line.

MEMBER WALLIS: So this is all metal fatigue we're talking about?

DR. CHANG: Yes. This is all metal fatigue. Yes, you can say that.

MEMBER SHACK: But driven mostly by

thermal.

MEMBER WALLIS: So what do you do with vibration fatigue? I mean, something like vibrating separators or something, --

DR. CHANG: Yes.

MEMBER WALLIS: -- what do you do about that? How do you know what the cycling load is?

MR. GILLESPIE: We had that issue, if you remember, at Dresden/Quad Cities because of the power uprate. And they had extensive vibrations down the whole main steam line. And in that case, now we're in negotiating space because GALL doesn't cover this.

In that case, the licensee agreed with the staff, not just for license renewal purposes, but they were instrumenting the entire line to try to get some data on what they had to do relative to dampening that vibration.

I think that was a commitment for like a one-year program at the time. I remember they came and discussed that with the committee.

MEMBER WALLIS: This is also after the fact, after you find that something is shaking. Then you start to investigate.

MR. GILLESPIE: At Dresden/Quad, it was after the fact. I hope we and the utilities are now smart enough for the next round of things.

CHAIRMAN SIEBER: In that instance, though, it's not clear that the deterioration would be to the piping system. It was knocking the valves apart, --

MR. GILLESPIE: Right.

CHAIRMAN SIEBER: -- position indicators and --

MR. GILLESPIE: Fundamentally the analysis wasn't refined enough to have seen the vibration. In the actual as-built situation when they went to the higher flows, --

CHAIRMAN SIEBER: Right.

MR. GILLESPIE: -- the darned thing had sympathetic vibrations down the whole steam line right to the turbine. So we were unable mathematically to predict it. So the staff took action on it. I mean, clearly if we could predict it up front, I think you would find the staff taking action.

So yes, that is a case by case. And that is one of the sensitivities of power uprates.

DR. CHANG: In special cases, the ASME code, the fatigue curve, has modified in history. It used to be the fatigue curve goes up to 10^6 cycles. Now the fatigue curve goes to the 10^{11} cycles.

Why do that? The purpose is to address the high-cycle fatigue, high-cycle, low-amplitude fatigue. If you have a case like that, then it depends on you measure the vibration frequency and amplitude.

You can address that's how many years to get a failure. If under that 10^{11} cycle, we call it under the induced limit. And those loadings, vibration loadings, will not cause failure until the ASME code changed again.

MEMBER WALLIS: You must have low amplitude, too.

DR. CHANG: Yes. I did say "amplitude," frequency and amplitude.

MEMBER WALLIS: We know that these steam lines are vibrating. Any idea about the amplitude and what governs it?

DR. CHANG: Say the amplitude and frequency depend on the configuration. You put certain frequency there. No. The piping span has certain frequency. And the measurement and monitoring will give you the amplitude.

You plug this in there. You see a single span, single span but it would be the maximum strength in a span. And that you show, that stress, is under the endurance limit. You're okay.

MEMBER WALLIS: Well, I was just wondering if you know enough to input the right thing into your analysis.

DR. CHANG: That's where experience counts.

MEMBER SHACK: Most of those you're not going to analyze up front. You know, you're --

CHAIRMAN SIEBER: Yes. It will break. And then you analyze it.

MEMBER SHACK: It comes after you go out and you make the measurements and you find out that you've got the problem. You can then sort of decide how bad it is.

MEMBER WALLIS: That's what concerns me. So you're not giving us sort of assurance by this slide that there's not going to be any problem of vibrations leading to fatigue?

CHAIRMAN SIEBER: No.

MEMBER WALLIS: No? You're saying that they do, then? What are you giving the credit for here: analyzing the things they could analyze and being within the code?

MEMBER SHACK: These are sort of analyzing the thermal fatigue problems they know they have --

MEMBER WALLIS: They know about. Okay.

MEMBER SHACK: -- and making sure that that analysis remains valid for the life of it. You know, the fatigue problems they have that they don't know about they haven't analyzed.

DR. CHANG: And those, back to the fatigue problem, it is most likely going to be discovered by walk-down, including --

CHAIRMAN SIEBER: Yes.

MR. GILLESPIE: Again, getting back to Dresden/Quad because that was one if you walked onto the turbine deck before they did the upgrade and increased flows and after, the noise was horrendous after.

So it's not just walking down looking at passive pipe. When you change, physically change, the plant, that's when you're going to find out. And that's what our experience is.

And the mathematical models aren't as perfect as we would like to think they are when you try to put in the pipe hangers and stuff. It's not that exact.

CHAIRMAN SIEBER: But from a calculational standpoint, it is far easier to look at thermally induced fatigue, --

MR. GILLESPIE: Yes.

CHAIRMAN SIEBER: -- which is a low-cycle fatigue, than it is to try to find the resonance point of some complex mechanical system, which I think is really tough to do.

MR. GILLESPIE: Now, in Brunswick's case, we could ask the licensee, did they see anything after they uprated because they are a power uprated plant.

CHAIRMAN SIEBER: Yes.

MR. GILLESPIE: I think the answer is no, there was no abnormal condition that was seen at Brunswick, but let's have the applicant because that will address your specific problem.

MEMBER WALLIS: Some of those uprates have only been in effect for a short while.

MR. GILLESPIE: It didn't take long to --

MR. GRANTHAM: This is Mark Grantham.

We did instrument main steam and feedwater lines inside primary containment as well as our MSIV pit. And there were some very slight increases in vibration level, but they were very --

MEMBER WALLIS: You have accelerometers or something on there?

MR. GRANTHAM: Yes, that is correct. There were minor increases and well within allowables.

MEMBER WALLIS: So this is what is going into this fatigue monitoring program? One of the inputs is the accelerometer readings from the steam lines? Is it? It's not?

CHAIRMAN SIEBER: No.

MEMBER WALLIS: I'm just not quite sure how the staff satisfies itself that everything is okay enough.

MR. GILLESPIE: Let me ask the licensee because it may not be. Your statement I think was that this was within allowables that you just made on the accelerometers?

MR. GRANTHAM: That is correct.

MR. GILLESPIE: Okay, which means it's encompassed in the uncertainties and considerations of the calculation.

MR. GRANTHAM: What we did was we went back and did a pipe stress analysis based on certain displacements and vibration and based on the allowables within the code determined what acceptable levels were.

MR. GILLESPIE: So I just don't want it to go on record that this was ignored. It wasn't ignored. It's actually encompassed in the analysis in the allowables and uncertainties within the analysis already.

So the staff finding is that what they're doing is acceptable. It wasn't ignored.

MEMBER WALLIS: That's what I'm trying to determine. That's all.

MR. GILLESPIE: We needed the dialogue to do that.

CHAIRMAN SIEBER: Okay. Moving on.

MR. MAURICE HEATH: All right. Moving on to section 4.4, "Environmental Qualification, EQ, of Electrical Equipment," the applicant's EQ programs consistent with GALL AMP, X.E1, "Environmental Qualification of Electrical Components," operating experience identified no age-related equipment failures that its program is intended to prevent. The staff concluded that the effects of aging or the intended function will be adequately managed for the period of extended operation.

Section 4.6, I want to highlight two TLAAs: the torus downcomer/vent header fatigue analysis and the torus, attached and safety relief valve piping system fatigue analysis. The staff found that the staff accepted the evaluation in accordance with 10 CFR 54.21(c)(1)(ii).

MEMBER WALLIS: Now, this fatigues because they test these from time to time or from time to time a relief valve is open and there is shaking in the torus downcomer? Is that what has happened?

MR. MAURICE HEATH: Ken?

MEMBER WALLIS: What is it that challenges this fatigue? What is it that causes the fatigue?

DR. CHANG: This is Ken Chang again. Speaking of this SRV piping system that is subject to the dynamic loading, those loadings can be determined. And then you can go into the stress calculation, evaluate stress level in the piping, and compare it to the ASME allowable in primary, secondary, and fatigue limits. That's what they mean.

MEMBER WALLIS: It gets pretty exciting, doesn't it, when you blow steam into the torus?

DR. CHANG: Oh, yes. That's lots of paper, publication that has generated over like ten years ago, traced back many, many years.

MEMBER WALLIS: So that's what you're calculating based on data you're calculating these loads?

DR. CHANG: That can not be experienced because that is a horrible experience.

CHAIRMAN SIEBER: You only do it once.

MR. MAURICE HEATH: Section 4.7, "Other

Plant-Specific TLAAs," I wanted to highlight one in particular: torus component corrosion allowance, the component supports classified as ASME section XI, "In-service Inspection Supports," and non-ASME section XI, "ISI Supports."

The staff needed additional information on calculations for corrosion rates for the ASME components and clarification on the one-time inspection program for the non-ASME ISI supports.

In letter dated March 31, 2005, the applicant presented calculations for corrosion rates and descriptions on one-time inspection program for non-ASME ISI supports.

The staff accepted the evaluation in accordance with 10 CFR 54.21(c)(1)(ii).

MEMBER SHACK: What's an ASME support and the non-ASME support?

MR. MAURICE HEATH: I'll defer to Hans Asher to answer that question for you.

MR. ASHER: My name is Hans Asher.

Inside the torus, there are two types of supports. One is ASME. Those are bearing the low pressure-containing components. They are all ASME components. But then there are certain supports which are like a structure supporting the grading or some other non-safety-bearing --

MR. MAURICE HEATH: Did that answer your question?

(No response.)

MR. MAURICE HEATH: All right. For a summary for section 4, the TLAA, according to the definition in 10 CFR 54.3, the TLAA list, as amended, was found adequate by the staff. And each TLAA met one of the definitions of 10 CFR 54.21 (c)(1)(i), either (i), (ii), or (iii).

And, with that, I would like to conclude the staff's presentation and ask if there are any more questions.

MEMBER BONACA: There were no (iii)'s, right?

MR. MAURICE HEATH: No. There were (iii)'s.

MEMBER BONACA: There were (iii)'s?

MR. MAURICE HEATH: In the metal fatigue portion.

MEMBER BONACA: Yes.

MR. MAURICE HEATH: They did a calculation 60-year to show that to the extended period of operation.

MEMBER BONACA: That reply means that you will manage the problem.

MR. MAURICE HEATH: I'm sorry. Yes. That's what fatigue monitoring programs are.

MEMBER BONACA: Okay. I didn't see those.

MR. MAURICE HEATH: Right.

MR. MITRA: That concludes our presentation.

CHAIRMAN SIEBER: Yes. Are there any other questions from members?

MEMBER WALLIS: So if something goes wrong with the intended function, then we say you guys didn't anticipate it in your review or we simply say that it's okay because it's being properly managed and it's going to be found and it's going to be cured?

You were interested in the management of it, not in trying to predict that there won't be any problems? You're just saying that they had the problem system set up so that they can manage the kind of problems that might arise?

MR. MAURICE HEATH: Yes. That is correct.

CHAIRMAN SIEBER: Any other questions or comments?

(No response.)

SUBCOMMITTEE DISCUSSION

CHAIRMAN SIEBER: Well, according to the

agenda, our next step is to have a Subcommittee discussion. To my viewpoint, the discussion focuses on whether the full committee should write an interim letter or not on the safety evaluation in the application and the applicant's and staff's activity so far in the review process.

Generally interim letters are written if there are significant issues that arise that appear to be taking a direction which would differ from ACRS' view of the final condition of the SER when the license extension is granted.

So what I would like to do is to go around the table and ask members, first of all, should we write an interim letter. And if we do, what should be the topics and issues that would be in that letter.

And then beyond that, I would be interested in knowing your overall assessment and comments as to individual items within both the application and the SER in today's presentations.

So, with that, I would like to ask Dr. Shack those questions and hear his comments.

MEMBER SHACK: Well, you know, since the staff has no open issues, I don't see any showstoppers here. So I don't see any particular need for an interim letter. The application seems like a fairly good one. I don't see any real problems.

CHAIRMAN SIEBER: Okay. That's good because if there were an interim letter, I would have to write it tonight.

(Laughter.)

CHAIRMAN SIEBER: Okay. Dr. Wallis?

MEMBER WALLIS: Yes. I don't think we need an interim letter. This SER actually is fatter and more extensive, I think, than some of the others we have seen at this point in time, from license renewal.

What I have been missing is sometimes a clarification at the end of a discussion about why the issue is resolved or why the evidence as presented meets some criterion. I think that can be fixed up in looking at the SER.

I mean, you can write it for the reader when you have 20 pages of discussion about Charpy being all these different numbers. I mean, why is it that you conclude that everything was okay? That's the kind of thing that I was after in my questions.

I think the substance is there, but it needs to be presented in a way which is absolutely clear why you reached the conclusion that everything was okay.

MR. MITRA: We will take a look at the -- we took note that you have described. And we will take a look at it and try to revise it.

CHAIRMAN SIEBER: Dr. Bonaca?

MEMBER BONACA: Yes. I second the comments of Graham.

CHAIRMAN SIEBER: Okay.

MEMBER BONACA: It's a common experience. I mean, the SER seems to serve a lot of purposes. One of them is to document all the exchange and interaction with the licensee. The result of it is that for a reviewer, like ourselves, at times you have to really go through until you find the conclusions of what you are looking for. And at times, it gets confusing more or less.

But with regard to this application, I think it was a very good application. It was very clear. And I think the SER also was thorough and complete.

I had the same trouble a little bit with TLAA because there was so much write-up and considerations. And, again, in search of the concluding statement, it was not easy.

Yes?

MEMBER SHACK: I was just going to say

part of the problem is that, you know, these things are now so linked and so documented you sort of have to know the whole history of things.

I sort of sat there deciding why it was okay they didn't have to commit to a hydrogen water chemistry in the license renewal. Well, then that shifted me to their BWR SEC corrosion program. And then that shifted me to the BWRVIP-76, which sort of said, you know, if you had the hydrogen water chemistry, you wouldn't have this much inspection, but if you turned off the hydrogen water chemistry, they were still covered because the BWR-76 would throw them into a new inspection program.

And somehow you have to just keep chasing down the thing. So the trail, it isn't as though the license renewal stands on its own anymore. It's infinitely linked.

MEMBER BONACA: Well, it's more of the complexity of our review because we discussed this at our retreat. I mean, it's how do you make it more efficient when you have to chase all of these issues, in fact? In some cases, I'm still puzzled about some of the responses I got.

But going back to the application, I think it was very good. SER 2 I am supportive of the fact that there are no open items. So I don't see any need for an interim letter at this time. And, in fact, I would expect that this will come back pretty soon for final review --

CHAIRMAN SIEBER: I would think so.

MEMBER BONACA: -- because of the condition of this application and the SER. So I have no further comments.

CHAIRMAN SIEBER: Otto, do you have any comments? It's sort of unfair to ask you because you haven't had the luxury of time like the rest of us have had.

MEMBER MAYNARD: Well, I'm not officially on this Subcommittee yet, but I'll offer opinions anyway.

CHAIRMAN SIEBER: I have never prevented anyone else from doing that.

(Laughter.)

MEMBER MAYNARD: As I understand the criteria, I wouldn't see a need for an interim letter on this one.

I don't have much of a reference point. I haven't had a lot of time looking at this or looking at others. But I would say that just from the overall thoroughness of the report and the lack of a lot of open items and open issues, that it would appear to me that both the utility and the NRC have been learning as this process has gone along, taken advantage of it. It's a good product overall.

CHAIRMAN SIEBER: My overall impression, by the way, is that as time goes on and more and more license renewal applications and SERs are written has a tendency to come to -- you know, you say this code word and I will say that code word.

It gets to the point I think that it becomes more difficult for the average person or average engineer to read and understand what all these things mean.

In the case of Brunswick, there are some unique features about this plant that don't exist in any other plant. In order to evaluate how the licensee treated it and how the staff reviewed their treatment from the standpoint of aging management, some of these unique features, like the containment, you know, almost require the FSAR plus some other access to documents, which basically aren't online.

This plant was built in 1970. I think the Radio Shack's TRS-80, which was the first commercial PC, came out seven years later. And so I don't expect to find that on the ADAMS system. On the other hand, that is available to the staff.

My way of doing this was to go through and find the unique features and things I didn't know about, make a list of questions, and then prompt the licensee and the staff to the fact that I had questions that they ought to address in this presentation.

I agree with my colleagues that we don't need an interim letter. This was a good SER. It was a good clean application or appears to be good cooperation between the applicant and the staff at resolving issues.

That's why there are no open items, a modest, relatively speaking, number of RAIs. And I think the process is maturing and the staff is getting more efficient at being able to conduct their reviews, turn out a good solid SER in the process.

In the design process if I were the designer back 30 or 40 years ago, which I was, but designers design little pieces of things, as opposed to gigantic things, especially when you're in your 20s and 30s age-wise, there are some things I might have done differently. On the other hand, the design does work.

The aging management that the licensee is conducting appears to satisfy the requirements. And with all the commitments that have been made, I think that one can conclude the plant will be safe for the extended period of operation.

So overall those are the conclusions that I came to. I appreciate the fact that I don't have to write an interim letter tonight as a draft. On the other hand, you never know. Maybe when the full committee hears my presentation tomorrow, I will end up writing an interim letter. One never knows.

What I would like to do is to thank the applicant and the staff for what I think is a job well-done and good preparation and good presentations to us today. And to all the reviewers, I think we're all learning to speak each other's language. Now that again makes it more efficient and understandable for us. And so, with that, I want to offer my thanks to all of you who are here for a good Subcommittee meeting today.

If either the staff or the applicant has any comments with regard to our process here or the overall license renewal process or license extension process, I think now would be a good time to do that.

Yes, sir?

MR. GILLESPIE: Frank Gillespie, NRR.

Some questions came up on the screening process.

CHAIRMAN SIEBER: Yes.

MR. GILLESPIE: And one of the initiatives the staff has kind of taken on is to do something in screening, smaller effort, but look at the past precedence and our past screening decisions. We are working with Billy Rogers and Greg Galletti, who are two of the team leaders who have been doing the process and to actually try to pull I'll call it a screening database together because the answer I don't think was the right answer you got on the bird screen.

We can chuckle about the bird screen, but you put a fan on a pump cooling house because you need ventilation because of that removal purposes during high temperatures, which can cause --

CHAIRMAN SIEBER: Birds go and then plug up the --

MR. GILLESPIE: Plug up the fan. And so it could actually fail, a system that can fail a safety system. And we didn't give you the safety answer. We shouldn't have said, "Well, that's part of the building."

And so we're pulling together this so that we can actually have some guidance for us and the licensees. And we're kind of doing it as time permits, but maybe by next fall, we might be ready to come and share it with the committee.

CHAIRMAN SIEBER: Okay.

MR. GILLESPIE: Because what it does is kind of sets a standardization of screening for people much as GALL gives a standardization for technical decision-making. So that's just a small initiative we have got going on. And you will probably hear some things about that in the future.

MEMBER WALLIS: I'm glad you brought that up because we get the impression from some of this that the only thing that matters is maintaining a boundary. There were actually heat exchangers and fans that are designed to cool things as well. There is another function besides just maintaining a boundary.

MR. GILLESPIE: Yes. And, again, I think the applicant answered that heat exchanger question and why. And every one of these components is kind of a unique reason. And you had to be there when you made that decision to try to rethink it when the committee asks the question on a specific component. So sometimes it appears that we don't have the answer, but hidden in the balls of our notes someplace is that answer.

And standardization of how we do it and how we consider it in sharing that might help bring some more understanding, universal understanding, to that.

CHAIRMAN SIEBER: Okay. Good. Thank you.

Are there any other comments?

(No response.)

CHAIRMAN SIEBER: If not, again, I want to thank everyone for the effort it took to prepare the presentations and the work that was done on the application and the SER. And, actually, that makes my job and the committee's job much easier on the work that was professionally done.

So, with that, I think that we can adjourn even a few minutes early.

(Whereupon, the foregoing matter was concluded at 4:14 p.m.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee

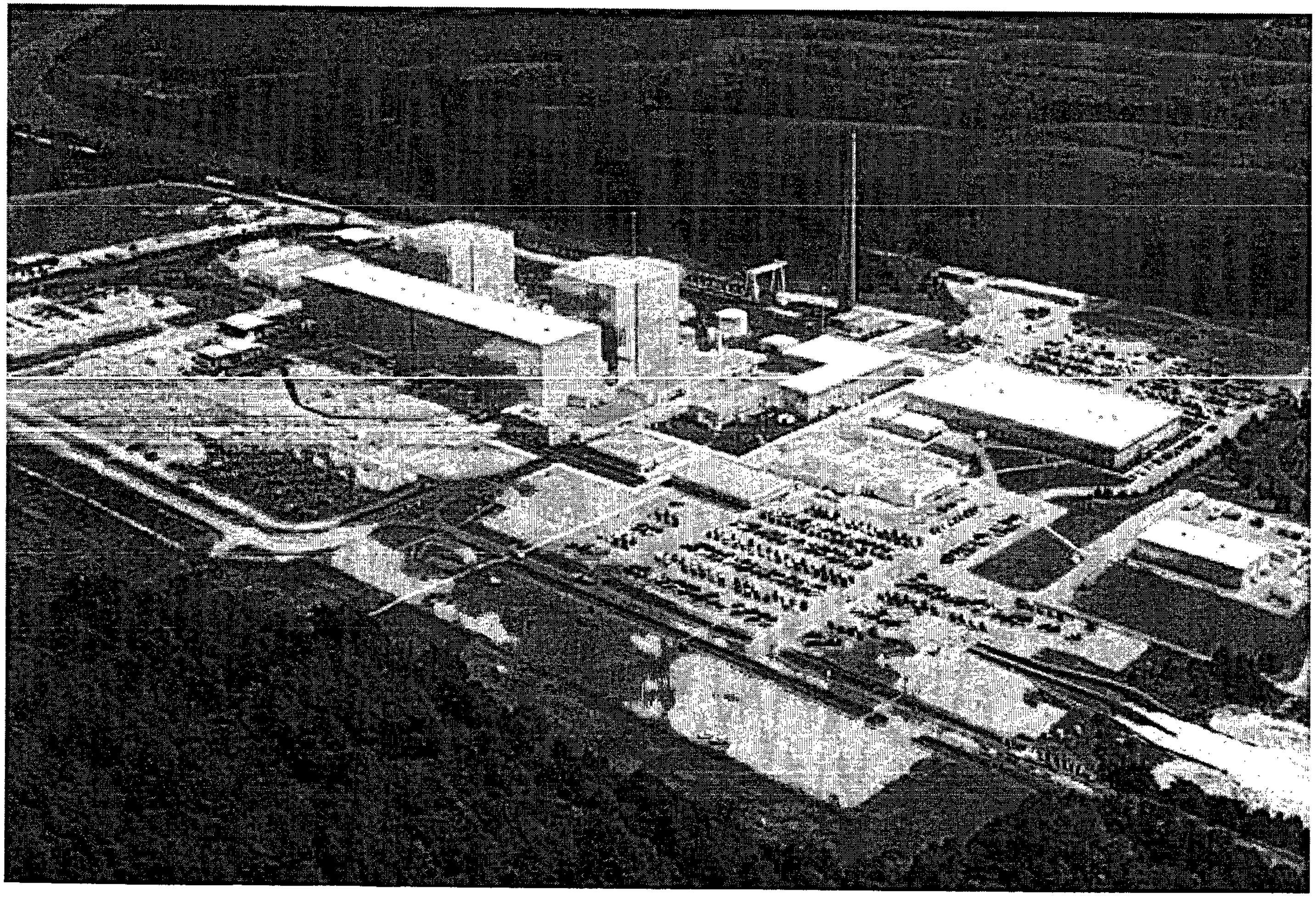
Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Lindsay Barnes
Official Reporter
Neal R. Gross & Co., Inc.

Brunswick Steam Electric Plant
Units 1 and 2



NGG

Progress Energy

Brunswick Steam Electric Plant
Units 1 and 2

License Renewal Presentation to ACRS Subcommittee

NGG Nuclear Generation Group

Progress Energy

Agenda

- Description of BSEP
- Operating History
- Current Plant Status
- Application Background
- LR Review Methodology
- Application of GALL
- Commitment Process

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Description of BSEP

- Located in Southport, NC
- Cape Fear River is Ultimate Heat Sink
- Dual unit GE BWR 4 with Mark I Reinforced Concrete Containment
- 560 Fuel Assemblies/Unit
- Hydrogen Water Chemistry plant

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Operating History

- Commercial Operation
  - Unit 1 March 1977
  - Unit 2 November 1975
- Current License Expiration
  - Unit 1 September 2016
  - Unit 2 December 2014

INDEX

Operating History

- Licensed Thermal Power History
  - Original licensed thermal power (OLTP)
    - 2436 MWt
  - 105% OLTP Uprate (November 1996)
    - 2558 MWt
  - 120% OLTP Extended Uprate (May 2002)
    - 2923 MWt

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Current Plant Status

- Unit 1
  - Operating in 15th cycle
  - Transitioned to 24 month cycles in 1997
  - Currently Operating at 100% rated power
  - Will enter a Refuel Outage March 4, 2006

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Current Plant Status

- Unit 2
  - Operating in 17th cycle
  - Transitioned to 24 month cycles in 1997
  - Currently operating at 100% rated power
  - Plant issues
    - White Unplanned Power Changes Performance Indicator

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Application Background

- LRA used Class of 2003 Format – May 2003
- Information conformed to:
  - NUREG-1800, SRP-LR, April 2001
  - NUREG-1801, GALL, April 2001
  - NEI 95-10, Rev. 3, March 2001
- Information in the LRA was developed in plant calculations

LR Review Methodology

- Scoping
  - Based on UFSAR, DBDs, Docketed Correspondence
  - Quality Class Review using Equipment Database
  - Focused Reviews for Regulated Events and Non safety Impacting Safety
    - NSR Steam Dryers and NSR Drains in scope
  - Addressed ISGs 1 through 20
- Aging Management Review
  - Class of 2003 table format
  - Provides NUREG 1801 Comparison
- Aging Management Programs
  - 34 AMPs Identified

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Commitment Tracking

- All Commitments are Tracked by the BSEP Corrective Action Program (CAP)
- Each Commitment Has an Implementation Plan
  - Each Implementation Plan Identifies all required actions
  - All actions are linked to the CAP
  - All actions have a due date and owner
- LR Program Procedure Will Track LR Activities
- Document Updates Scheduled for 2006

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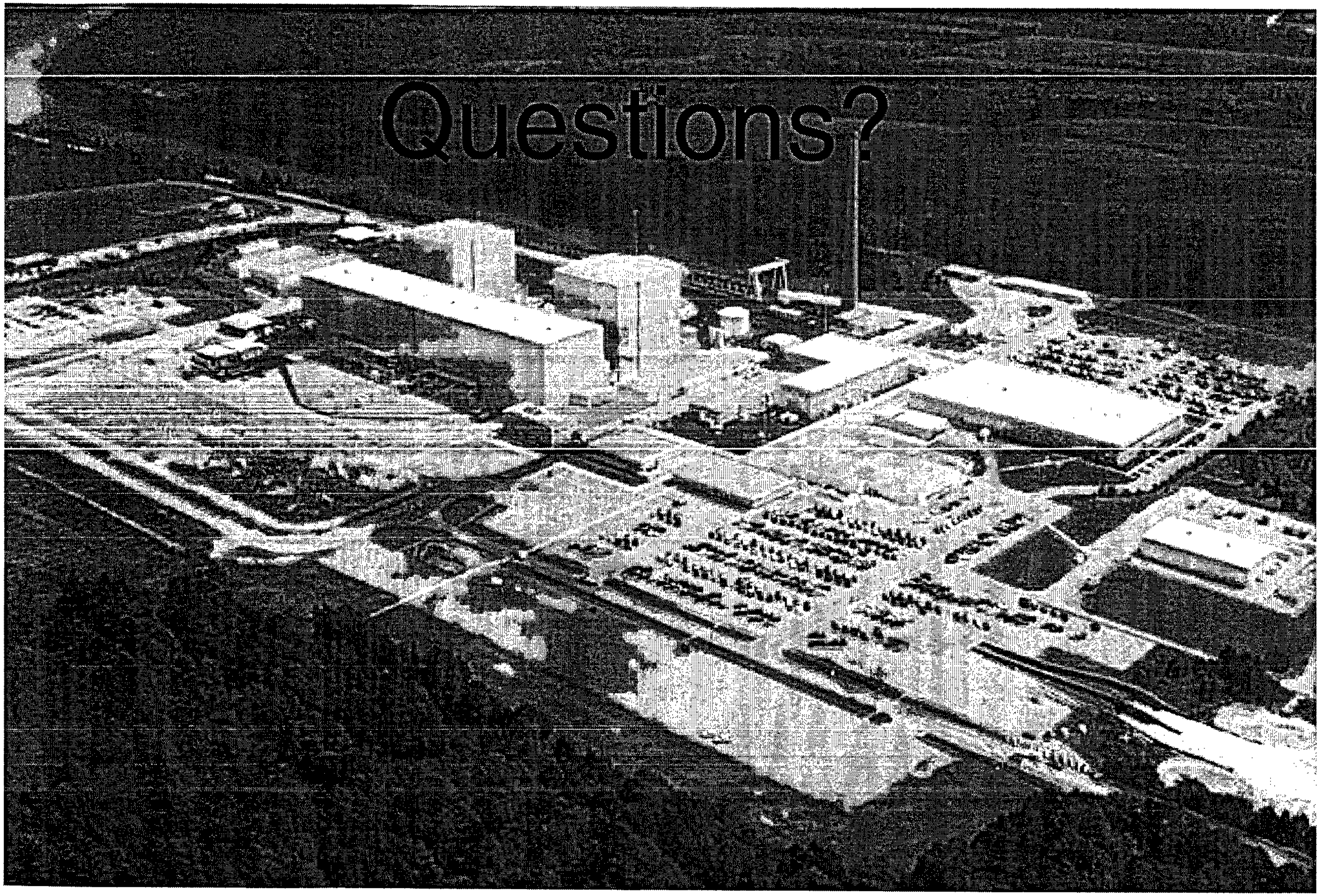
Conclusion

- The New Audit Process Effective
- Early Identification of Concerns Allowed Early Resolution



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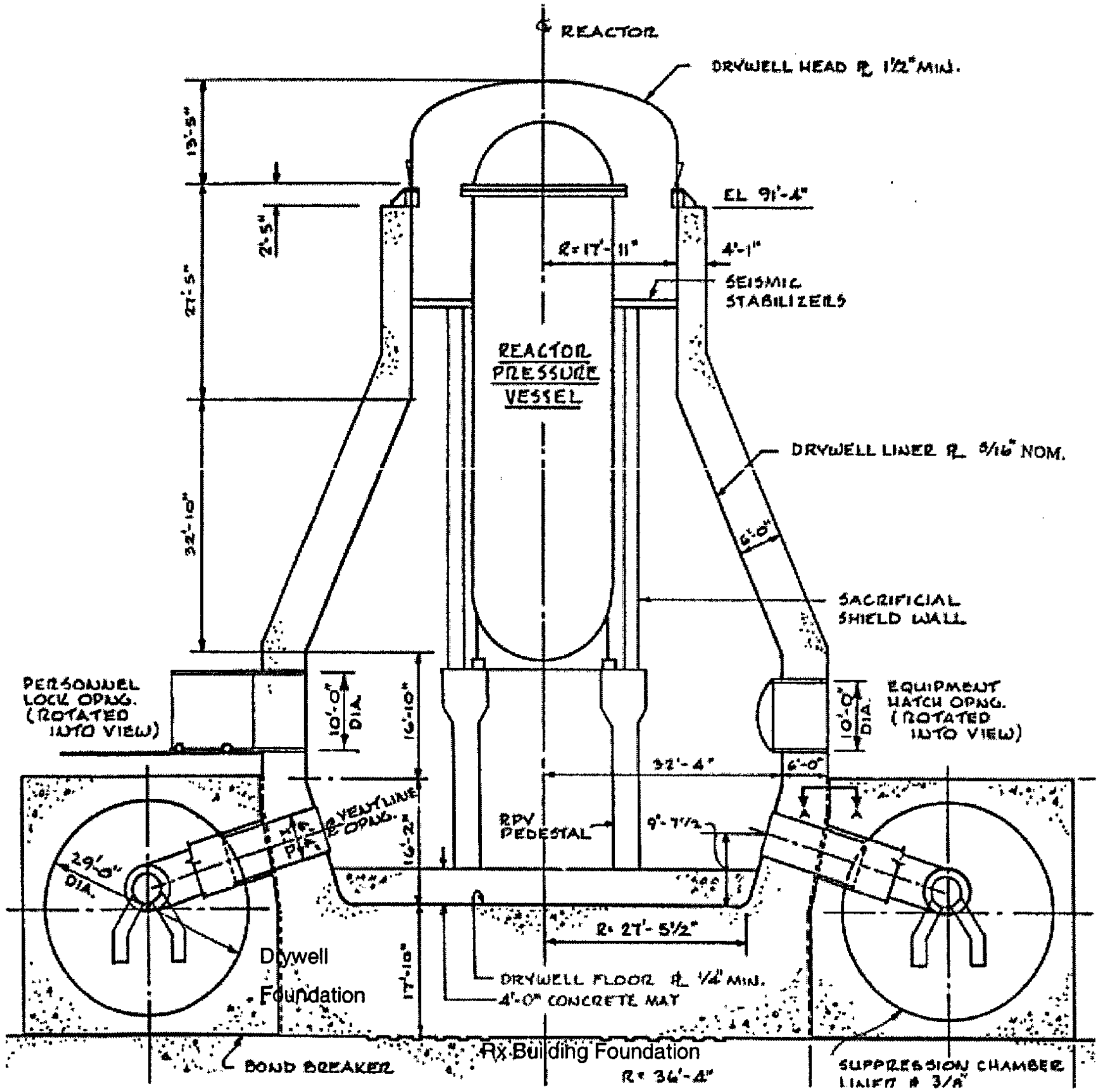
Mark I Reinforced Concrete Containment



NRC Information Notice 2006-01
BWR Mark I Containment Torus Cracking

- The Brunswick HPCI exhaust:
  - utilizes a sparger configuration
  - significantly different from the Fitzpatrick configuration (turned down elbow within 2-1/2 feet of the torus shell).
- The BSEP torus is steel lined, reinforced concrete
- The Fitzpatrick Torus is free standing steel.

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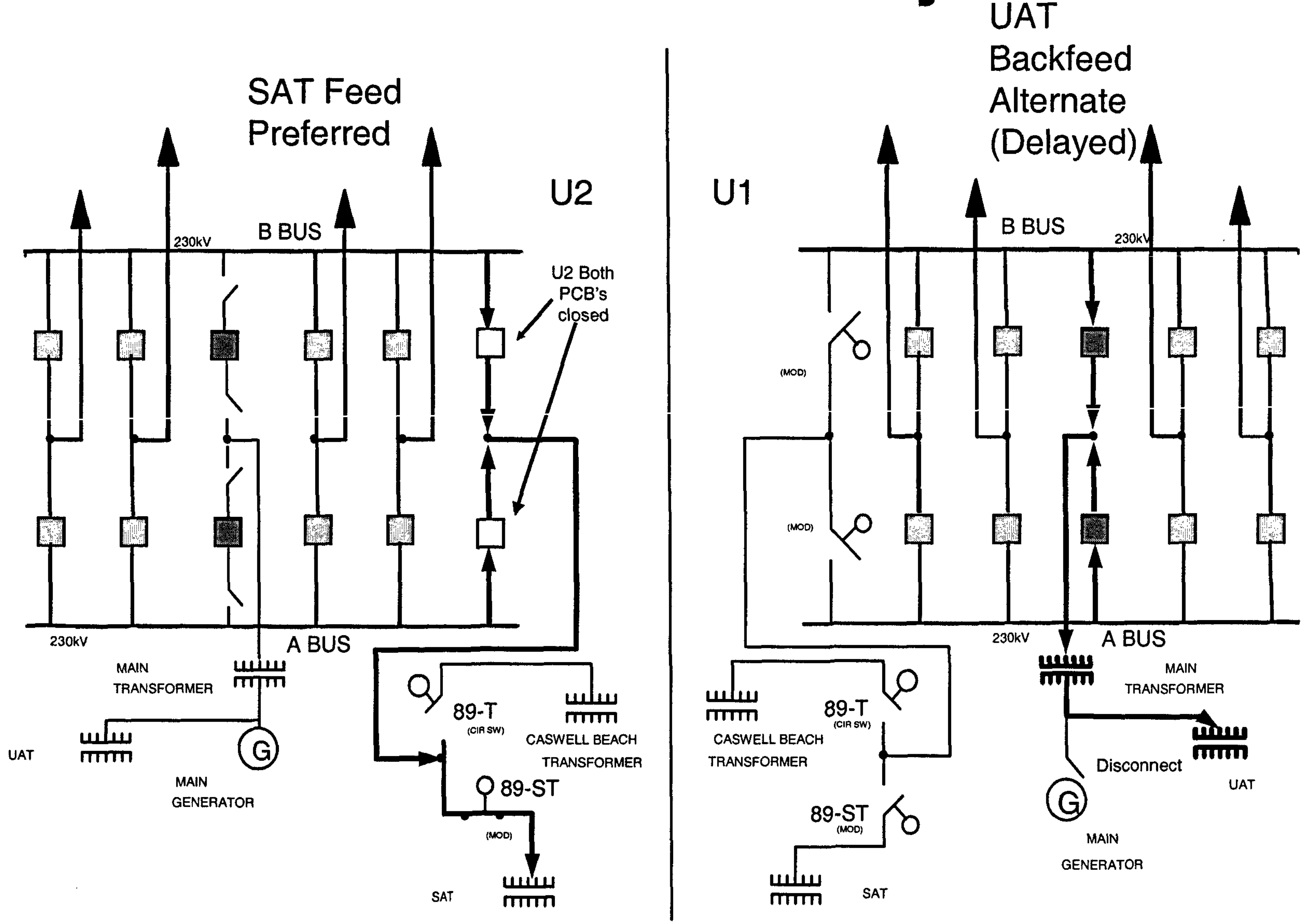
SBO Recovery



BSEP Steam Dryer Review

NGG Nuclear Generation Group

Progress Energy

Steam Dryer Background

- BSEP has a BWR-4 slanted hood dryer
  - Does not include internal diagonal brace attachments
  - Lower resultant stresses
- BSEP has significantly lower steam line velocities than other dryers damaged post-EPU
  - BSEP – 146 ft/sec
  - Damaged dryers post EPU >200 ft/sec
  - Steam line velocities remain in the middle of the BWR fleet

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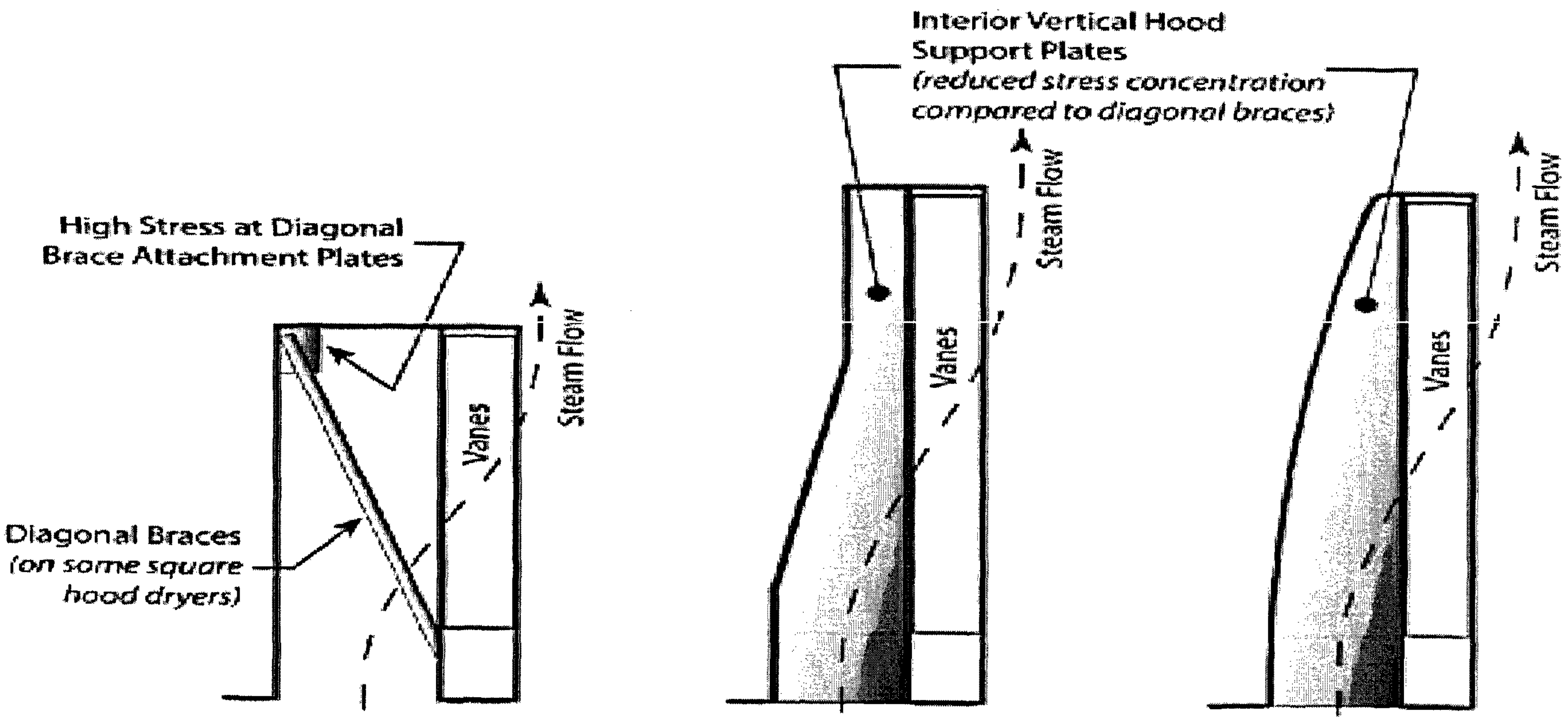
Steam Dryer Designs



Square Hoods
BWR/3 Style Design

Damaged Dryers Post EPU

Slanted Hoods
BWR/4 Style Design
Improved Steam Flow

BSEP Steam Dryer

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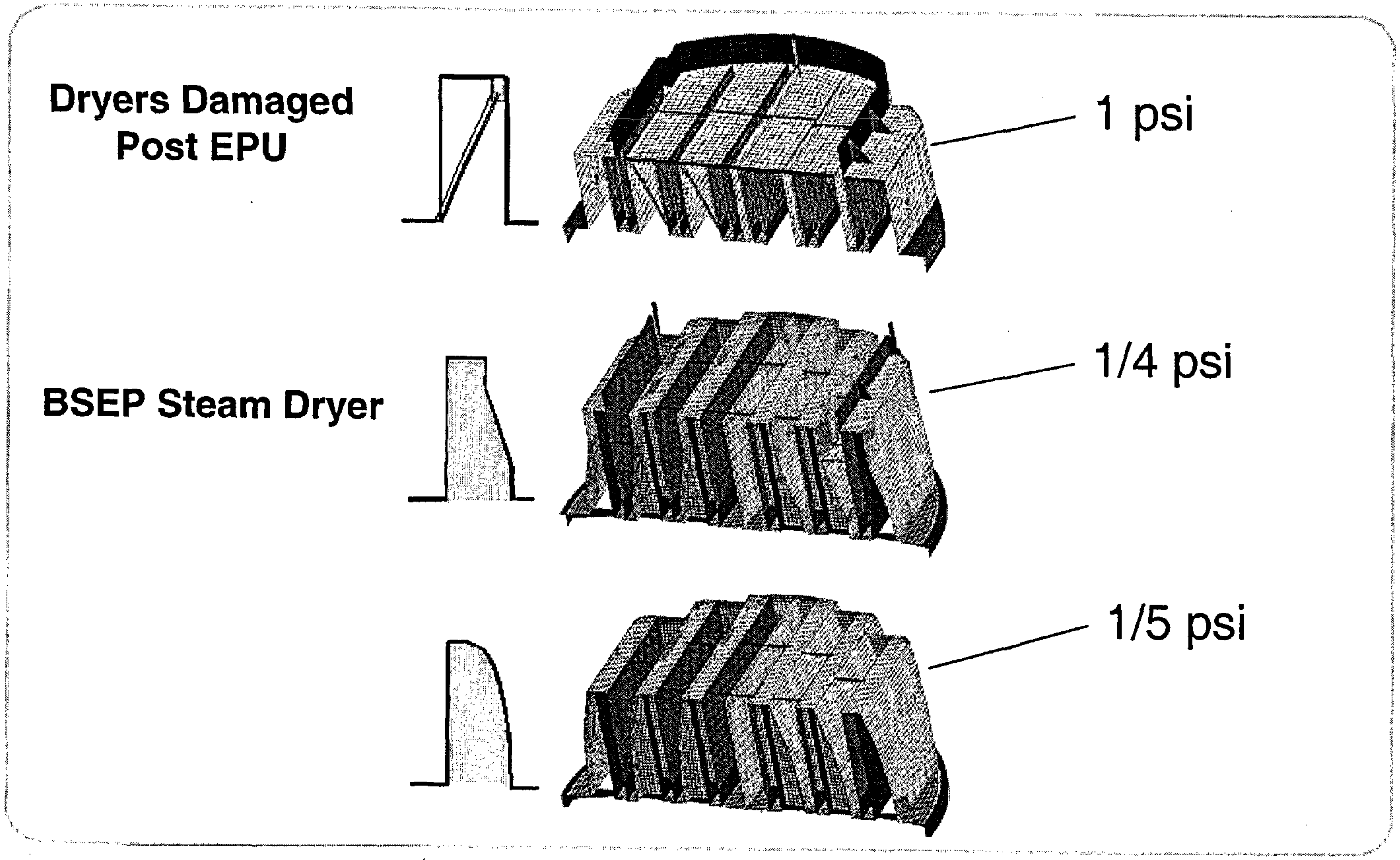
Curved Hoods
BWR/5 Style Design
Optimized Steam Flow

NGG

Progress Energy

Relative Stress on Dryer Hood



BSEP Steam Dryer Inspections

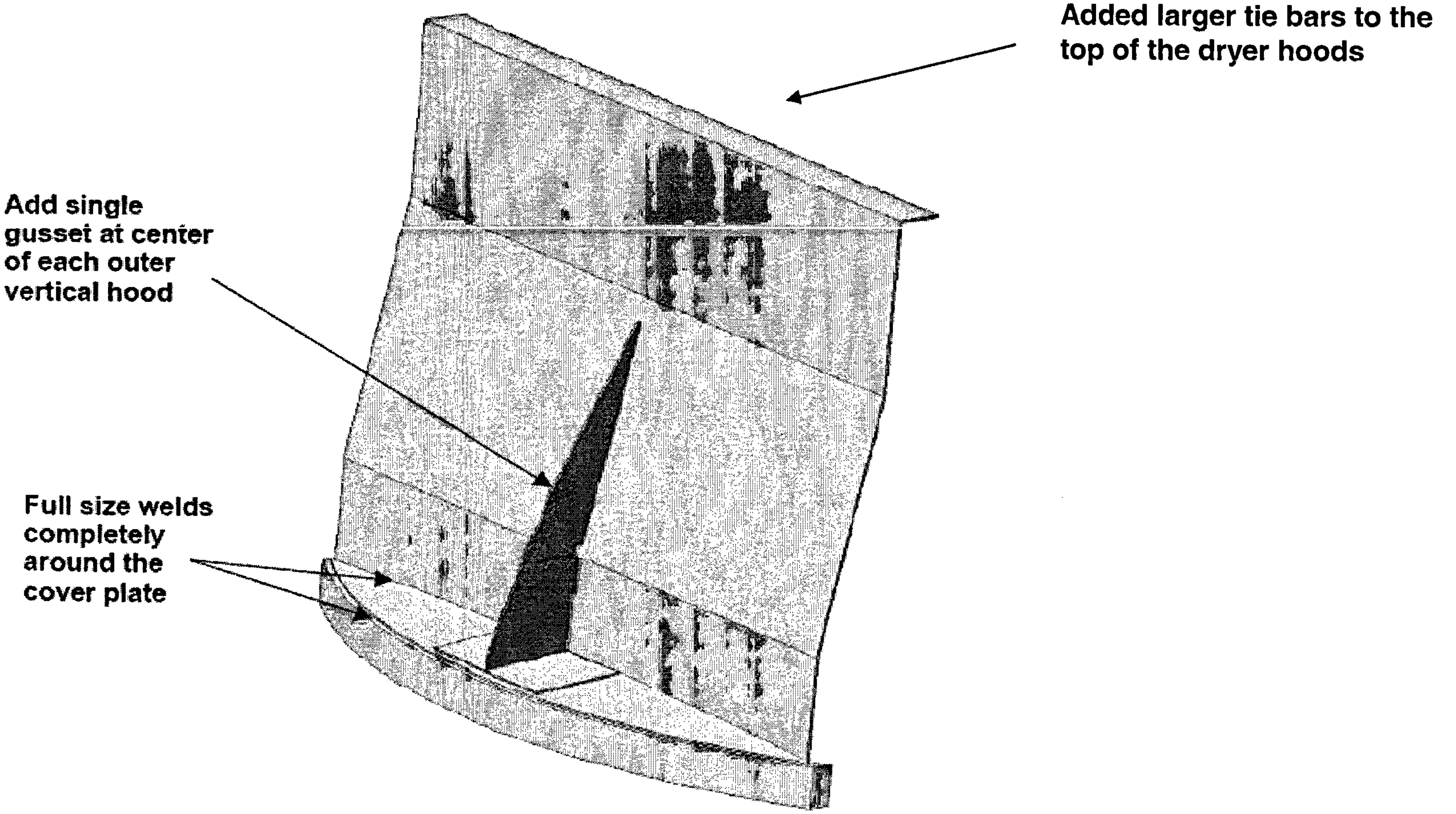
Unit 1

- June 2002 -Uprate to 113% OLTP
- Sept. 2002 – General inspection during mid-cycle outage – No degradation noted
- March 2004 – 100% exterior inspection and dryer modification performed – minor weld repairs
- April 2004 – Uprate to 120% OLTP
- April 2005 – Inspection performed during mid-cycle outage – No new degradation noted
- March 2006 – Planned inspection during refuel outage

Unit 2

- April 2003 – Uprate to 116% OLTP
- March 2005 - 100% exterior inspection and dryer modification performed – minor weld repairs
- April 2005 – Uprate to 120% OLTP
- May 2006 – Planned inspection during mid-cycle outage
- March 2007 – Planned inspection during refuel outage

BSEP Steam Dryer Modifications



BSEP Operating Experience with EPU

- Fatigue failure of EHC return line for main turbine control valves
  - Interim power level was likely a contributor
  - Industry OE with these types of failure exists
  - Piping modified to a flexible connection
- Socket welded drain line failures
  - Previous industry and BSEP OE with these types of failures
  - Changed socket weld configurations to a more fatigue tolerant design

BSEP Operating Experience with EPU

- Condensate/Feedwater system response
  - System response during minimum flow valve operation
  - Higher condensate pressures
  - Optimization of system operation
- Main generator disconnect switch failure
  - Switch design did not support the continuous rating
  - Modified to a hard bus configuration

U2 Unplanned Power Changes per 7000 Hours Critical

- Occurrences causing transition to White
  - April '05 – 2B Reactor Feed Pump Impeller Failure
  - June '05 – 2B Circulating Water Intake Pump Trip Due to Debris Loading
  - August '05 – Dual Unit Shutdown Due to Identified Legacy Issue with Diesel Generator Differential Protection Circuit
  - November '05 – Three Unit Downpowers due to Tube Leaks in the 2A Condenser Water Box
  - December '05 – 2B Reactor Recirculation Pump MG Set Trip due to Failure of Fuse in the Voltage Regulation Circuit
- NRC Supplemental Inspection February 2006

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Brunswick Steam Electric Plant (BSEP) Units 1 and 2 License Renewal Safety Evaluation Report

Staff Presentation to the ACRS

Sikhindra (SK) Mitra, Project Manager
Office of Nuclear Reactor Regulation

February 8, 2006

Introduction

- Overview
- NRC Review Process
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Review Results
- GALL Review and Audits
- Aging Management Programs
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- LRA submitted by letter dated October 18, 2004
- GE Boiling Water Reactors, Mark 1 design containments
- BSEP located at the mouth of Cape Fear River in Brunswick County, NC, two miles north of Southport, NC
- Unit 1 expires September 8, 2016, Unit 2 expires on December 27, 2014
- Request operating license extensions 20 years beyond the current expiration dates

Overview (continued)

- Each unit generates 2923 MW thermal, 1007 MW electrical – Include 20% Extended Power Uprate (EPU)
- Applicant committed to review plant and industry operating experience, relevant aging effects caused by operation at power uprate. The evaluation will be submitted for NRC review one year prior to period of extended operation (Commitment # 31)

Overview (continued)

- SER issued on December 20, 2005
  - No Open or Confirmatory Items
  - 3 license conditions
  - 174 RAIs issued via 4 letters and 39 Audit questions requiring supplements
  - Brought into scope
    - Switchyard Breakers
    - Service Water Intake structure fan, dampers, bird screen
    - Condensate Storage Tank Piping Credited for SBO

NRC Review Process

- Scoping and Screening Methodology Audit
- Consistency with GALL Audits
  - AMPs
  - AMRs
- Technical staff in-house safety review
- Regional inspections
  - Scoping and Screening Inspection
  - AMP Inspection

NRC Review Process
(continued)

- AMP GALL Audit
  - January 10 – 14, 2005
- AMR GALL Audit
  - February 7 – 11, 2005
- Scoping and Screening Methodology Audit
  - February 28 – March 4, 2005
- Regional Scoping and Screening Inspection
  - June 6 – 10, 2005
- Regional AMP Inspection
  - June 20 – 24, 2005

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.1, Scoping and Screening Methodology
  - Staff audit and review concluded that the applicant's methodology satisfies the rule pursuant to 10 CFR 54.4 a and 10 CFR 54.21
- Section 2.2 , Plant Level Scoping Results
  - Staff identified no omission of systems and structures within the scope of the license renewal as defined by 10 CFR 54.4 criterion

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.3, Scoping and Screening Results - Mechanical Systems
  - Reactor Vessel, Internals and Reactor Coolant System
  - Engineered Safety Features
  - Auxiliary Systems
  - Steam and Power Conversion Systems

Two – Tier Scoping Review for BOP Systems

- Two – Tier Scoping Review Based on Screening Criteria
  - Safety Importance/Risk significance
  - Systems Susceptible to Common Cause Failure of Redundant Trains
  - Operating Experience Indicating Likely Passive Failures
  - Previous LRA Review Experience of Omissions
- Tier 1: Screen, Review (LRA, FSAR), Identify Systems for Inspections
- Tier 2: Review (Boundary Drawings, and Other Licensing Basis Documents in Addition to LRA, FSAR)

Two – Tier Scoping Review

- 62 Mechanical Systems
- 39 are BOP (Most Auxiliary and Steam and Power Conversion Systems)
  - 15 BOP Systems Selected for Tier 1 Review
  - 24 BOP Systems Selected for Tier 2 Review
- 23 Mechanical Non BOP Systems (RCS, Engineered Safety Features, Some Aux Systems), Continue to Receive Tier 2 review
- Electrical and Structural Receive Tier 2 review.

Section 2.3, Scoping and Screening Results - Mechanical Systems

- Condensate storage tank piping credited for SBO brought into the scope
- Service water intake structure fan, bird screen and damper housings are brought into scope.

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.4, Scoping and Screening Results – Structures
  - Containment
  - Other Class 1 and in-scope Structures (15)

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.5, Scoping and Screening Results – Electrical and Instrumentation and Control (I&C) Systems
  - Guidance contained in NEI 95 10Appendix B was used in developing a list of electrical and I&C commodity groups
  - Switchyard breakers (230 kv gas- filled power circuit breakers) represent the first breakers for SBO recovery path are brought into scope of license renewal

Scoping and Screening Summary

- The applicant's scoping methodology meets the requirements of 10 CFR Part 54
- Scoping and screening results as amended included all SSCs within the scope of license renewal and subject to AMR

License Renewal Inspections

- Scoping and Screening Inspection
- Aging Management Inspection
- Commitment Tracking
- Plant Reactor Oversight Process (ROP)

License Renewal Inspection Program Implementation

- License Renewal Manual Chapter – MC 2516
- License Renewal Inspection Procedure – IP 71002
- Site-specific inspection plan
- Scheduled to support NRR safety review

License Renewal Inspections

- Scoping and Screening Inspection
  - Objective: to confirm that the applicant has included all appropriate SSCs in the scope of license renewal as required by 10 CFR 54.4
  - Conducted June 6 – 24, 2005
    - MC 2516 and IP 71002 have been revised to reduce the scope of Scoping and Screening inspections and combine them with Aging Management Program inspections
    - Focus is on 10 CFR 54.4 (a) (2) situations- non safety related that could effect safety related equipment

License Renewal Inspections

- Incorporated 3 - Tier – 1 Scoping Review Inspections
  - Heat Tracing Systems
  - Moisture Separator Reheater Drains and Reheat Steam System
  - Heater Drains and Miscellaneous Vents and Drains
- Concluded that the applicant's scoping and screening process was successful in identifying those SSCs requiring AMR

Aging Management Program Inspection

- Objective: to confirm that existing AMPs are managing current age related degradation
- Applicant established an implementation plan in the plant Action Request system to track committed future actions
- Inspectors found a few examples where actions committed in AMP description documents were not yet in implementation plan.
- Applicant promptly made needed corrections and several changes.
- Material condition of plant was being adequately maintained
- Documentation was of very good quality, supported by a comprehensive computer database

Brunswick, Unit 1 3Q/2005 Performance Summary

Performance Indicators

Unplanned Scrams (G)	Emergency AC Power System Unavailability (G)	Reactor Coolant System Activity (G)	Drill/Exercise Performance (G)	Occupational Exposure Control Effectiveness (G)	RETS/ODCM Radiological Effluent (G)
Scrams With Loss of Normal Heat Removal (G)	High Pressure Injection System Unavailability (G)	Reactor Coolant System Leakage (G)	ERO Drill Participation (G)		
Unplanned Power Changes (G)	Heat Removal System Unavailability (G)		Alert and Notification System (G)		
	Residual Heat Removal System Unavailability (G)				
	Safety System Functional Failures (G)				

Brunswick, Unit 2 3Q/2005 Performance Summary

Performance Indicators

Unplanned Scrams (G)	Emergency AC Power System Unavailability (G)	Reactor Coolant System Activity (G)	Drill/Exercise Performance (G)	Occupational Exposure Control Effectiveness (G)	RETS/ODCM Radiological Effluent (G)
Scrams With Loss of Normal Heat Removal (G)	High Pressure Injection System Unavailability (G)	Reactor Coolant System Leakage (G)	ERO Drill Participation (G)		
Unplanned Power Changes (G)	Heat Removal System Unavailability (G)		Alert and Notification System (G)		
	Residual Heat Removal System Unavailability (G)				
	Safety System Functional Failures (G)				

Section 3: Aging Management Review Results

- 3.1, Reactor Vessel, Internals, and Reactor Coolant System
- 3.2, Engineered Safety Features Systems
- 3.3, Auxiliary Systems
- 3.4, Steam and Power Conversion Systems
- 3.5, Containments, Structures and Component Supports
- 3.6, Electrical Components

Aging Management Programs (AMPs)

- Total 34 AMPs
- Consistent with GALL: 9
- Consistent with GALL, with deviations: 20
- Plant Specific: 5

EXAMPLES OF AUDIT AND REVIEW TEAM FINDINGS AND RESULTS

- Originally used Risk Informed ISI program for AMP, ASME Section XI, In service Inspection, Subsections IWB, IWC and IWD Program
  - Modified AMP to be consistent with GALL, ASME Section XI, & 50.55a: added periodic volumetric, surface and visual examinations

- Originally committed to inspect and clean RHR and EDG jacket water heat exchangers prior to the period of extended operation
  - Modified Open Cycle Cooling Water AMP to include performance testing (heat transfer capability) [Commitment 4]

EXAMPLES OF AUDIT AND REVIEW TEAM FINDINGS AND RESULTS

- Originally committed to inspect buried piping only during opportunistic inspections
  - Modified Buried Piping AMP to say [Commitment 13]
    - Opportunistic inspection may be used to satisfy inspection requirements, but in no case will frequency of inspection exceed 10 years
    - Inspection by qualified coating inspector
- Structures Monitoring Program originally not consistent with GALL
  - Modified AMP to [Commitment 16]
    - Include inspections of the submerged portions of the Service Water Intake Structure on a frequency not to exceed five years
    - Specify annual groundwater monitoring inspection frequency for concrete structures
    - Specify inspection frequency for the Service Water Intake Structure and Intake Canal to not exceed five years

Section 3.1, Reactor Vessel, Internals, and Reactor Coolant System

- Reactor Vessel and Internals
- Neutron Monitoring System
- Reactor Manual Control System
- CRD Hydraulic System
- Reactor Coolant Recirculation System

Reactor Vessel and Internals Structural Integrity Program (RV&ISIP)

- The RV&ISIP is a plant-specific aging management program
- The RV&ISIP inspections are based on the augmented inspections recommended in BWRVIP
- Commitment # 22 defines which BWRVIP reports are included in the scope of the RV&ISIP and additional specific augmented activities that will be taken by the applicant

Reactor Vessel Surveillance Program (RVSP)

- The RVSP monitors for the impact of neutron irradiation on the fracture toughness properties of RV materials
- The RVSP is based on the integrated surveillance program criteria in BWRVIP-78 and BWRVIP-86
- The RVSP will be enhanced to include conformance with the updated integrated surveillance program criteria in BWRVIP-116, once approved by the NRC (Commitment #10)

Section 3.2, Engineered Safety Features Systems

- 10 Plant-Specific Systems
- In response to RAI 3.2.4, the applicant is committed to manage the loss of material and cracking for small-bore Class 1 piping in treated water (include steam) (internal) environments, using the One Time Inspection program (commitment 11)

Section 3.3, Auxiliary Systems

- 34 plant-specific systems
- Applicant committed to add to Preventive Maintenance Program, routine sampling and analysis to address corrosion concerns related to potential water intrusion into lubricating oil in the Service Water Pump Motor Cooler Coils and the Emergency Diesel engines Lube Oil System (Commitment 24)
- Additionally, applicant committed to add to One Time Inspection Program at least one of the four Emergency Diesel Engine Sumps and at least one of the ten Service Water Pump Lubricating Oil Cooling coils for corrosion products and evidence of moisture (Commitment 11)

Section 3.4, Steam and Power Conversion Systems

- 13 Plant Specific Systems
- The applicant's AMR result for the titanium components in a raw water environment was an issue requiring additional information. The applicant clarified that the titanium in a raw water environment at a temperature less than 160 degree F does not exhibit aging effects. The titanium tubes in a raw water environment are at a temperature less than 160 degree F.

Section 3.5, Containments, Structures and Component Supports

- Containment
- Other Class 1 and In-Scope Structures (15)
- BSEP Credits ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J for management of Drywell Liner
- Both IWE and Appendix J requires 100% inspection per period, there are 3 periods per interval, and each interval is ten years.

Aging Management of In-Scope Inaccessible Concrete

	Aggressive Limit	BSEP
pH	<5.5	6.4 – 7.5
Chlorides	>500 ppm	11 – 49 ppm
Sulfates	>1500 ppm	2 – 66 ppm

- Ground water phosphate level at 0.12 ppm
- Below grade environment is non-aggressive

Section 3.6, Electrical and I & C

- Component/Commodities subject to AMR
  - Non-EQ Insulated Cables and Connections
  - Phase Bus
  - Non-EQ Electrical/ I & C Penetration Assembly
  - High Voltage Insulators
  - Switchyard Bus
  - Transmission Conductors

Section 3.6, Electrical and I & C

- Applicant committed to add to Preventive Maintenance Program, periodic inspection of High-Voltage Insulators for Water Beading on Silicone Coating and for age related degradation (Commitment 24)
- Applicant committed to include in the Phase Bus Aging Management Program, inspecting the interior condition of the bus enclosure and perform thermography on a 10 year- frequency while bus is energized and loaded (Commitment 25)

Section 4: Time-Limited Aging Analyses (TLAAs)

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

Section 4.2, Reactor Vessel Neutron Embrittlement

- Ten TLAAs identified on neutron irradiation embrittlement
  - Neutron Fluence Calculations
  - Upper-Shelf Energy (USE)
  - Pressure-Temperature (P-T) Limits
  - Adjusted Reference Temperature
  - Circumferential Weld Calculations
  - Axial Weld Probability of Failure Analysis
  - Shroud Repair Hardware Analysis
  - Core Plate Plug Analysis
  - Core Shroud Thermal Shock Reflood Analysis
  - RV Thermal Shock Reflood Analysis (Added in response to RAI)

Reactor Vessel (RV) Upper Shelf Energy (USE) Equivalent Margins Analysis (EMA)

RV Material	TLAA (EMA) Basis	Acceptance Criterion	BSEP-1 Value	BSEP-2 Value
Limit. Plate	BWRVIP-74-A %Drop in USE	<23.5	21.0 (BSEP) 21.0 (Staff)	17.0 (BSEP) 17.1 (Staff)
Limit. Weld	BWRVIP-74-A %Drop in USE	<39.0	14.1 (BSEP) 14.1 (Staff)	13.3 (BSEP) 13.5 (Staff)
Nozzle Forging	Plant Specific - Fluence (n/sq cm)	<1.6E18	1.38E18 (Staff)	1.38E18 (Staff)
Nozzle Weld	BWRVIP-74-A %Drop in USE	<35.0	12.0 (Staff)	12.0 (Staff)

- TLAA for USE/EMA were in all cases determined to be acceptable under 10 CFR 54.21(c)(1)(i) or (ii)

RV Circumferential Weld/ RV Axial Weld Probability of Failure Analyses

RV Material	TLAA Basis	Acceptance Criterion (° F)	BSEP-1 Value (° F)	BSEP-2 Value (° F)
Limiting Circ. Weld	BWRVIP-05 Mean RT_{ndt} Value in ° F	<70.6	6.6 (BSEP) 6.6 (Staff)	-34.1 (BSEP) -34.1 (Staff)
Limiting Axial Weld	BWRVIP-05 Mean RT_{ndt} Value in ° F	<114.0	53.0 (BSEP) 52.8 (Staff)	53.0 (BSEP) 52.5 (Staff)

- TLAAs for the Circ. Weld and Axial Weld Mean RTndt values were in all cases determined to be acceptable under 10 CFR 54.21(c)(1)(i) or (ii)

Section 4.3, Metal Fatigue

- Effect of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)
  - Applicant performed refined fatigue analysis based on data collection from Cycle Evaluation Module (CEM) and finite element analysis from Fatigue Monitoring Program to show CUF will remain below the ASME Code limiting value
  - Staff found applicants assessment acceptable in accordance with 10 CFR 54.21(c)(1)(ii)

Section 4.4, Environmental Qualification (EQ) of Electrical Equipment

- Applicant's EQ Program consistent with GALL AMP, X.E1, "Environmental Qualification of Electrical Components"
- Operating Experience identified no age-related equipment failures that its program is intended to prevent

Section 4.6, Containment Liner Plate, Metal Containments and Penetration Fatigue Analysis

- Torus Downcomer/Vent Header Fatigue Analysis
- Torus – Attached and SRV Piping System Fatigue Analyses
- The staff accepted the evaluation in accordance with 10 CFR 54.21(c)(1)(ii)

Section 4.7, Other Plant Specific TLAAs

- Torus Component Corrosion Allowance
  - Component supports classified as ASME Section XI, In-service-Inspection (ISI) supports and non-ASME Section XI, ISI supports
  - Staff needed additional information on calculations for corrosion rates for ASME components and clarification on One Time Inspection program for non-ASME ISI supports
- In letter dated March 31, 2005 the applicant presented calculations for corrosion rates and descriptions on OTI program for non-ASME ISI supports
- The staff accepted the evaluation in accordance with 10 CFR 54.21(c)(1)(ii)

TLAA Summary

- TLAA
  - 10 CFR 54.3
    - TLAA list adequate, as amended
  - 10 CFR 54.21 (c) (1)
    - (i) - analysis remain valid for period of extended operation
    - (ii) - analysis have been projected to the end of the period of extended operation
    - (iii) - effects of aging on the intended function will be adequately managed for the period of extended operation.