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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

May 4, 2006

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

532nd MEETING

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Thursday, May 4, 2006

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The meeting came to order at 8:30 in room T2B3 of 2 White Flint North, Rockville, MD, Dana A. Powers, Chairman, presiding.

PRESENT:

GRAHAM WALLIS	CHAIRMAN
WILLIAM J. SHACK	VICE CHAIRMAN
GEORGE E. APOSTOLAKIS	MEMBER
J.SAM ARMIJO	MEMBER
MARIO V. BONACA	MEMBER
RICHARD DENNING	MEMBER
THOMAS S. KRESS	MEMBER
OTTTO C. MAYNARD	MEMBER
DANA A. POWERS	MEMBER
JOHN D. SIEBER	MEMBER AT LARGE
JOHN LARKINS	DESIGNATED FEDERAL OFFICIAL

I-N-D-E-X

M-O-R-N-I-N-G S-E-S-S-I-O-N

8:30 a.m.

CHAIRMAN WALLIS: On the record. The meeting will now come to order. This is the first day of the 532nd Meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: the Final Review of the License Renewal Application for the Brunswick Steam Electric Plant; the Final Review of the Extended Power Uprate Application for R.E. Ginna Nuclear Plant; the Final Review of the Extended Power Uprate Application for the Beaver Valley Nuclear Plant; Proposed Revisions to 10 CFR Part 52 "License, Certifications and Approvals for Nuclear Power Plants;" and the Preparation of ACRS Reports.

I would like to remind the members that we have several reports to write, so do not leave until we have finished writing them on Friday.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the Designated Federal Official for the initial portion of the meeting. We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

A transcript of portions of the meeting is being kept and it is requested that the speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume so that they can be readily heard. I would now like to turn to the first item on the agenda and I invite my colleague, Jack Sieber, to get us started. Jack.

MEMBER SIEBER: Thank you, Mr. Chairman. The first item on the agenda, of course, is the Final Review of the License Renewal Application for the Brunswick Steam Electric Plant and I would like to call on Louise Lund of NRR to introduce the speakers and to move forward with the presentation.

MS. LUND: Thank you very much and good morning. For the record, I am Louise Lund. I'm the Chief for the License Rule Branch A of the Division of License Renewal and I'm going to introducing Sikhindra Mitra and also Maurice Heath who will be making the presentations this morning to you and the staff has completed the final safety evaluation of the Brunswick Steam Electric Plant, Units 1 and 2, the license renewal application and we will be giving a presentation today with the assistance of the support of the staff and also we have, I understand, Coudle Julian from the region that's on the speaker phone this morning. Coudle Julian was the Inspector Team Leader at Region 2.

MEMBER SIEBER: Yes. Why don't we see? Coudle, are you there?

MR. JULIAN: Yes, I am. Good morning.

MEMBER SIEBER: Welcome and good morning.

MR. JULIAN: Thank you.

MS. LUND: Okay. And also we have the support of the License Renewal Branch C who is responsible for the audit activities for this project. We received the license renewal application October of '04 and there was a draft safety evaluation issued in January of '06 and the final safety evaluation was issued in March '06. And with that, I will turn it to S.K.

MR. MITRA: I am S.K. Mitra. I'm the Project Manager for Brunswick Steam Electric Plant, Unit 1 and 2. But first, a presentation will be done by the Carolina Power and Light and Mike Heath is my counterpart in CP&L. Thank you.

MR. HEATH: Good morning. I am Mike Heath and we're here to talk about the Brunswick Steam Electric Plant license renewal application. The agenda is as we have shown here. We're going to give you a short overview of the application itself. We've been asked to discuss specifically in terms of operating experience our drywell liner and vibrations associated with power uprate. We'll be discussing our major equipment replacements and repairs, discussing exceptions to GALL and then we'll be discussing our commitment process.

The Brunswick Steam Electric Plant is located in Southport, North Carolina which about 30 miles south of Wilmington at the mouth of the Cape Fear River. The Cape Fear River is our ultimate heat sink for the plant. We are a dual unit, GE BWR 4 with a Mark 1 reinforced concrete containment. That containment is unique in the industry and Mr. Overton will discussing that in more detail in just a moment. Both units have achieved 120 percent power uprate.

CHAIRMAN WALLIS: Usually we refer to the power uprate as being the change. So this would normally be called a 20 percent power uprate.

MR. HEATH: Yes sir.

CHAIRMAN WALLIS: Okay. Otherwise, it's remarkable.

MR. HEATH: It is a remarkable plant. Our current license expiration for Unit 1 is September of 2016 and for Unit 2 is December of 2014. This application was prepared using the Class of 2003 format. The information in our application was developed using our plant calculations. We used the plant calculations so that our process would confirm with our plant Appendix B's Quality Assurance Program. The application address all the ISGs 1 through 20. We identified 34 aging programs and the SER when issued in December had no open items and no confirmatory items.

Mr. Overton will discuss our drywell liner operating experience.

MR. OVERTON: Good morning. My name is Tom Overton. I'm the Lead License Renewal Civil Engineer for the Brunswick plant and I will be presenting a brief overview of our containment design and our operating experience.

The Brunswick containment is unique in the industry. It's the only Mark 1, steel lined reinforced concrete containment. We have no annular space between the metallic liner and the reinforced concrete. Our concrete is poured flush with the liner and as such, we have no sand pockets, no sand bed regions.

This is the overview of our containment structure. Our liner on this side is backed by six feet of reinforced concrete for the majority of the structure and in the upper reaches, it's four feet of concrete. The liner and the concrete work in conjunction to provide an impervious barrier, a pressure boundary. The liner and the concrete work together to perform or provide the pressure boundary.

The upper areas of the drywell, I'm going to focus on that a little bit because I wanted to talk about the bellows region. There's been a lot of discussion with the bellows and I wanted to explain how our bellows region is designed and the bellows region is in this area right here and it goes and attaches to the vessel. (Indicating.)

This is a blown-up picture of the bellows area. The reactor vessel is right here. The reactor building is right here. (Indicating.) This area above would be flooded during a refuel operation. The head would be removed and there would be water in this area right here, demineralized water.

If we had a leakage of our refueling bellows which are these bellows right here, the water would go into the reactor building. It would not go behind the liner. As you can see from this picture, the concrete is flush with the liner and it would have to pass through this metal plate to get behind the liner which we inspect. This is part of our IWE program. So these components are inspected.

MEMBER SIEBER: Is there any opportunity under any circumstance for water to get between the concrete and the liner?

MR. OVERTON: No.

MEMBER SIEBER: Do you have any evidence through your in-service inspections that that has occurred?

MR. OVERTON: No, we do not. In the next slide, I'll talk about our operating experience right now. We've had -- I'll talk about three events we've had. In 1993, we had some corrosion at the liner concrete interface right here. (Indicating.) This is where our moisture barrier is located. In 1993, we had corrosion along the perimeter of that interface. We removed the moisture barrier, excavated the concrete in that area, cleaned, repaired the liner where required, recoated, placed the concrete back and put an enhanced moisture barrier in and this moisture barrier is a high density silicon elastomer and it's actually shaped to direct the water away from the liner. So we've had no more problems in this area right here.

In 1999, we had three through-wall events of our containment liner. One event was associated with some foreign material that was behind the liner. It created a bulge in the liner and the inspectors identified it and it was a through-wall event. The other two were events from corrosion from inside the containment going through the liner back towards the concrete.

In all three events, they did a local leak rate test to determine whether we had containment integrity and in all three cases, we were still acceptable for our L_a limits for containment integrity. So we didn't lose containment integrity in any of those cases and in fact, in one of those cases the inspectors had actually opened the hole up, probed, removed corrosion before we did our tests. It was in a much worst case situation.

MEMBER SIEBER: Now the liner itself is carbon steel.

MR. OVERTON: It's a carbon steel liner 5/16th of an inch thick through the majority of the containment. The penetrations in the torque, it's 3/8th of an inch thick.

MEMBER SIEBER: What kind, if any, protective coating is there on the liner?

MR. OVERTON: We have a Class 1 coating on the liner.

MEMBER SIEBER: Paint.

MR. OVERTON: Yes, it's paint.

MEMBER SIEBER: Both sides or just on the inside.

MR. OVERTON: Just on the inside.

MEMBER SIEBER: And so there is no protective coating on the concrete side.

MR. OVERTON: Well, the concrete is effectively the protective coating. Highly alkaline concrete will provide the protection. As a result of these events, we've enhanced our IWE program. We've included the inspection of bulges in the program and now when the IW inspectors do their inspections, if they identify a bulge by procedure, they're required to grid the area and perform ultrasonic testing, thickness measurements in the area.

Those results are attached to the inspection report and sent to the IWR responsible engineer and he'll review it and determine whether there's an issue with this particular case. They also included or enhanced the criteria to look for inclusions in the paint which is basically blisters and that's what we attributed to the two through-walls from the containment side to the concrete side. So they look for these blisters when they do their inspections.

MEMBER SIEBER: Now the containment like all Mark 1 containment is inerted during operations.

MR. OVERTON: Yes, it is inerted.

MEMBER SIEBER: Okay.

MR. OVERTON: The third event was a bulging of our liner in the personnel access hatch and in this area, it was identified again through the IWE and we identified the bulge. We did the UTs and we found material loss. They did weld overlays, repaired these areas.

And they looked in the other areas where this had occurred and we attributed it to a failed EPDM wrapping around the barrel of the penetration. They believe there was a tear in the coating that allowed moisture into it and it just through the years began to corrode and bulge the liner out in those areas. Those are three main events.

CHAIRMAN WALLIS: I don't understand the bulge. The bulge is presumably pushed from behind.

MR. OVERTON: That is correct.

CHAIRMAN WALLIS: So it's just the rust which is pushing it.

MR. OVERTON: Yes. The corrosion products.

CHAIRMAN WALLIS: A lot of rust to have a noticeable bulge.

MR. OVERTON: There's a lot more volume of rust than there is the original material and --

CHAIRMAN WALLIS: The bulge presumably is how big? A inch or something? How much does it stick out?

MR. MITRA: This is S.K. Mitra. Can you show -- You have some pictures of the bulge. Can you show how the bulge looks like?

MR. OVERTON: We do have a slide that shows --

CHAIRMAN WALLIS: If you're going to see a bulge, it has to be somewhat prominent presumably.

MR. OVERTON: You csn see -- The way the inspectors look for them, they look for them like they look for defects in drywall at your home. They put a flashlight against the wall and they look for shadows.

CHAIRMAN WALLIS: Look for anything, yes.

MR. OVERTON: And if they see shadows. Now here, there's a bulge right here.

CHAIRMAN WALLIS: Yes, it looks like a big bulge.

MR. OVERTON: Yes, it's pronounced. It's pronounced and a little bit here.

CHAIRMAN WALLIS: There are really bulgy

areas there.

MR. OVERTON: Yes.

CHAIRMAN WALLIS: Might not look at this too long.

MEMBER SIEBER: You might have to shut down.

MR. OVERTON: That being the case, let's go to the gridded area. I have a slide. The next -- There we go and this is the same bulge where we had cleaned the liner. We gridded it, did ultrasonic thickness measures and I think in a couple of cases we did some weld overlays to enhance the thickness.

VICE CHAIRMAN SHACK: How thin was it?

CHAIRMAN WALLIS: Well, see. His finger's underneath the level there. So it's presumably at least as thick, as big, as his finger.

MR. OVERTON: I'm not exactly certain how much material was loss.

CHAIRMAN WALLIS: Your finger underneath that. Right? So is it a half inch bulge sticking out?

MR. OVERTON: Probably. I don't know. They're not required to measure the depth of the bulge. They are required to do ultrasonic to determine the depth of the material, but I'm not sure how high the bulge is.

MEMBER DENNING: What are we actually seeing here? What are the black marks in this grid?

MR. OVERTON: The black dots are the grid. When they identify a bulge, the inspectors will grid the area.

MEMBER DENNING: I see. So they put those in there.

MR. OVERTON: Yes, and then they'll do ultrasonic thickness measures in each of these grids and then these grids will be mapped on the inspector report and it will be sent to the responsible engineer to evaluate. In the last IWE inspection which was a month ago, they identified, I believe, eight bulges in the lower area of the containment. They did the gridding. They performed ultrasonic thickness measurements and they found there was no material loss on any of these areas.

MEMBER ARMIJO: What's the mechanism that's causing these bulges? Water must be getting behind the paint and why would that happen?

MR. OVERTON: In these cases, these bulges were not caused by water. They were from original construction and that's what they were attributed to. When we did the ultrasonic measurements, no material loss was found there. In these bulges, we believe there was water from original construction that had caused the corrosion process to begin. That was many years ago and it's just been a slow process that allowed it to reach this point.

MEMBER BONACA: You said before that on the bottom you had corrosion that you had to repair.

MR. OVERTON: That's correct.

MEMBER BONACA: Was that water intrusion that caused the corrosion also from the original construction?

MR. OVERTON: That water was on the inside of containment. That wasn't --

MEMBER BONACA: Inside. Okay.

MR. OVERTON: That wasn't behind the liner.

MEMBER POWERS: Could you go again this argument that these bulges are due to original construction?

MR. OVERTON: Yes. In the last inspection, we identified bulges in the containment. Those bulges were gridded. Ultrasonic measurements were made. Thickness measurements were made of it. There was no material loss associated with any of those areas. So they have attributed the bulges to just construction defects.

CHAIRMAN WALLIS: Is there a void behind the bulge then?

MR. OVERTON: No.

CHAIRMAN WALLIS: Or is there containment concrete everywhere?

MR. OVERTON: No. It's just the natural of the construction process. We had an effectively thin plate with a lot of concrete pressure against it. It could have been a natural bulge in the material from the weld in the studs in the backside.

MEMBER SIEBER: So you should have found them the very first day that plan was reading for operation. Right?

MR. OVERTON: And it's possible they saw them then, but the IWR inspections didn't, we didn't start inspecting for bulges until later on in the plant life and most of these things -- We're getting a lot better with the IWE program. They've identified these things in the past, but they haven't kept records of them. Following these events, we started to maintain an accurate record of these, so we won't duplicate a lot of work in the inspection process.

MEMBER BONACA: When you go to repair them and you cut them, you find behind rust or it's simply the formation due to the original construction. I'm trying to understand if the mechanism is intrusion of moisture at the time of construction. That stays there and then causes corrosion to develop or if it is a different mechanism.

MR. OVERTON: What we found in the areas where we have removed the liner, it's been a dry powdery, what we've classified as inactive corrosion. The concrete has been fine. There is no staining on the concrete and they've identified no radioactive particles or anything that would have indicated that water transgressed from the fuel pool down to those areas.

MEMBER SIEBER: Well, it would seem to me that if you are classing these bulges as inactive corrosion.

MR. OVERTON: No, we were classing them as original construction.

MEMBER SIEBER: Okay. That means that if you find a new one, that argument is not longer valid if you find a new bulge that you haven't previously identified.

MR. OVERTON: And that's why we do ultrasonic measurements. If we identify a new bulge it's possible that it just wasn't identified in a previous inspection. So we would do --

MEMBER SIEBER: Or it may have grown.

MR. OVERTON: Exactly.

MEMBER SIEBER: And in fact if it did grow, that means you have active corrosion or some active mechanism going on that deserves your attention.

MR. OVERTON: And our process would identify that. We would do our ultrasonic measurements and if there was material loss, then we would take the appropriate action.

MEMBER MAYNARD: I'm hearing two or three different examples here that we may be getting confused. One, you have some bulges from original construction. Those there is no void behind that. There's no corrosion behind those. So those are still attached or in contact with the concrete.

MR. OVERTON: That's correct.

MEMBER MAYNARD: You have some others that was some corrosion from inside the containment that started and that you do have a few that were corrosion between the liner and the concrete.

MR. OVERTON: There were two cases of corrosion from the backside. In one case, there was a foreign object against the liner. It was actually a glove from original construction and it had we believe held enough moisture to create a corrosion process and that created the bulge in the through-wall. In the other case, we believe a tear in the EPDM wrapping around the barrel of the liner in the event allowed moisture in and allowed the corrosion to start, but those two are one of foreign object and the other a construction issue.

The majority of the containment liner does not have this wrapping around it. These wrappings were effectively a bond breaker between the barrel and the liners that pass through. The majority of the liner is flush with the concrete.

MEMBER SIEBER: Maybe I can ask one last question on this and allow you to move on. When you do the thickness measurements that's a ultrasonic measurement.

MR. OVERTON: Yes.

MEMBER SIEBER: What's the minimum wall that's acceptable under your code?

MR. OVERTON: Well, under IWE, ten percent is normally the level that brings it to attention. We will do a calculation if anything exceeds that.

MEMBER SIEBER: And that's based on the nominal thickness of --

MR. OVERTON: Of the 560.

MEMBER SIEBER: -- the liner as installed.

MR. OVERTON: Yes, that's correct.

MEMBER SIEBER: Okay.

VICE CHAIRMAN SHACK: I have one. When you find an event, does that change the frequency of your subsequent inspections?

MR. OVERTON: Yes, it does and it depends on how the event was evaluated. If we find an issue, say these bulges that we identified in a previous inspection and we check the thickness and they were found to have no material loss, the frequency of those would not change. If we found one where we actually had corrosion where we were experiencing degradation, that would go into an augmented program under IWE and augmented inspections would be performed in those areas.

VICE CHAIRMAN SHACK: Just locally then?

MR. OVERTON: Yes.

VICE CHAIRMAN SHACK: How about an area expansion? If you find something in one place, do you look harder elsewhere?

MR. OVERTON: Certainly, and the case with the personnel access hatch, when we found the bulges in these areas, we looked at other areas that we had wrapped with this felt EPDM wrapping to see if we had some bulges in those areas.

VICE CHAIRMAN SHACK: Now is it mandated that you do that or you just did it?

MR. OVERTON: I'm not sure that it's -- That is exactly how we would handle the process. I'm not sure that there is a requirement to expand it.

MEMBER BONACA: When you expand it, you expand it visually just to look for bulges or do you expand the UT?

MR. OVERTON: We would expand it logically based on the circumstances of the event we found. In the case of the wrapping material, we looked at all materials that had the wrapping material. In the case of the inclusions in the paint where we created a through-wall, we started looking more actively for these inclusions in the paint.

MEMBER MAYNARD: I would assume that your overall corrective action program requires you whenever you find a problem, part of the evaluation, is any generic implications or do you need to go look at other places whether it be for this or for other things?

MR. OVERTON: That's correct and it also forces us to look at the other unit too to see if we had and in fact, that's what we did with these. Our corrective action process basically drove us to inspect the other areas in the other unit for the same issues.

MEMBER SIEBER: I would point out that the process of getting liner bulges is not unique to this plant. Large dry containments that have a steel or a liner particularly in the subatmospheric containments where you put a vacuum in there and try to suck the liner off the concrete and you can actually do it, there has been in a lot of those containments bulges like this and not necessarily indicative of corrosion, just a phenomenon that occurs. So even though the containment is unique for a BWR, the process is not unique.

MEMBER BONACA: But the bottom -

CHAIRMAN WALLIS: But you can get a big bulge.

MEMBER SIEBER: Yes.

MEMBER BONACA: But the bottom line for license renewal is what's your plan.

MR. OVERTON: We will be managing our liner with the IWE in Appendix J programs. We've committed to that through the period of extended operation.

MEMBER SIEBER: Maybe we can move on because we're --

MEMBER POWERS: I'll help you get a little farther behind time here.

MR. OVERTON: Okay.

MEMBER POWERS: You've discussed the bellows up at the top. Do you have a bellows on your downcomers into your suppression pool?

MR. OVERTON: Yes.

MEMBER POWERS: And how do they look?

MR. OVERTON: They haven't been -- There's a liner. They are not inspected typically -- They are in our IWE program, but we've just completed an ILRT which effectively inspects them. It provides a pressure boundary check and they are fine based on our ILRT.

MEMBER POWERS: That means that you pressurized them and they didn't vent.

MR. OVERTON: And they didn't leak, yes.

MEMBER POWERS: That doesn't mean they're corroding.

MR. OVERTON: Right.

MEMBER POWERS: Do you think they are corroding?

MR. OVERTON: I do not believe they are

corroding.

MEMBER POWERS: Can you imagine that they're not?

MR. OVERTON: Well, they're in a dry, inerted environment and they're made from stainless steel. So based on our understanding of aging effects associated with that material in that environment, we do not believe there's corrosion.

MEMBER POWERS: Faith is a wonderful thing. Confirmation would be useful.

MR. HEATH: Any other questions?

MR. OVERTON: All right. I'd like to turn this over to Mr. Mark Grantham for discussing vibration of extended power uprate.

MR. GRANTHAM: Good morning. I'm Mark Grantham. I'm the Superintendent of Design Engineering. I'll be discussing our vibration experience associated with our extended power uprate. I'll also be going over some of the major equipment replacements and refurbishments that we've done over the last few years.

Part of EPU we did instrumented vibration monitoring on our main steam and feedwater piping, particularly in the inaccessible areas of our drywell and MSIV pit. We were monitoring main steam and feedwater because there was roughly a 15 percent increase in flows associated with that. This monitoring was conducted in accordance with Part 3 of the ASME Operation and Maintenance Code which covers pre-op and start up vibration testing.

To determine where we monitored, we did do a modal analysis of the piping to determine sensorial locations. We used accelerometers at those locations. We did observe an increase in the vibration levels in that piping with increasing flows and increasing power. But the vibration levels were maintained well below the allowable stresses.

We looked at essentially a case study here for main steam piping and this was the worst case we saw. At a particular location, the max vibration, and this is at a 420 power, was only 15.5 percent of the Code allowable for steady state vibration stress and again this is the worst case.

CHAIRMAN WALLIS: This is for the piping itself. It's not being used to diagnose what's happening in the dryer or anything like that.

MR. GRANTHAM: That is correct.

MEMBER SIEBER: What of your inspection results? What are the results for your dryer?

MR. GRANTHAM: For steam dryer, we've

inspected our dryer essentially all along, I guess, our implementation of uprate. We implemented uprate over two cycles. We just in March had a refueling outage on Unit 1 which was after two full years of operation at 120 percent.

The steam dryer inspections revealed no new degradation. We have had some old degradation that's been there for years, IGSEC type degradation, but no new degradation, no crack growth and again, we inspected at the beginning of uprate and every cycle along the way through implementation and again, after a cycle of full uprate, we saw no new degradation.

MEMBER SIEBER: Do the Mark 4 dryers for the ones with the slope?

MR. GRANTHAM: That is correct. We have the slanted dryer hood arrangement which is if you look at the stresses given a constant loading on the dryer, the dryers that had failed post EPU our stress levels would be roughly a quarter of what those stresses would be in the square hood type dryer.

MEMBER SIEBER: That dryer though did have a weakness at the bottom at the right angle weld.

MR. GRANTHAM: Correct.

MEMBER SIEBER: Have you repaired that?

MR. GRANTHAM: We did do modifications to our dryer as part of uprate. The cover plate weld which was the initial failure that occurred at Quad Cities, we did beef-up that weld from 1/4 inch to a 3/8ths inch weld. We did add a stiffener to the hood face that came down and joined at the top of the cover plate and we also replaced the tie bars at the top of the dryer which there's been a lot of industry OE with those bars failing as well.

MEMBER SIEBER: Is the dryer in scope?

MR. GRANTHAM: That is correct. It is in license renewal scope.

MEMBER SIEBER: What's your aging management program for the dryer?

MR. GRANTHAM: There is a BWR/VIP document that now covers dryer inspections. It's BWR/VIP 139 as well as a GE seal which we're implementing which is seal 644 which covers inspections and the general inspections are a baseline inspection. If you do have degradation, monitor the dryer for each outage after you identify any existing flaws to confirm that you're not seeing crack growth and once you establish that, every other refueling outage do an inspection and this is a VT-1 inspection.

MEMBER SIEBER: Thank you.

MR. GRANTHAM: All right. Moving along to feedwater piping and this is typical of our feedwater piping. All of the vibration levels were extremely low in feedwater. For this particular case, the vibration was actually about one percent of the allowable stress and again, that's typical of what we saw in feedwater for both our units.

MEMBER POWERS: Is there any small diameter piping where I might expect bigger changes?

MR. GRANTHAM: Generally, the criteria for small bore piping has been as long as the large bore piping is maintained less than 50 percent of the allowables, you generally don't consider the smaller bore piping. I'm getting ready to talk about it here in a second, but we have had some small bore piping vibration issues primarily with socket weld type joints. There's a lot of industry OE with those type failures. We had OE at Brunswick before extended uprate and we've taken some actions in those areas where we have had failures and were concerned about the vibration.

VICE CHAIRMAN SHACK: But you don't actually monitor the locations that have failed.

MR. GRANTHAM: That is correct. Continuing, I guess, with that discussion, over on our BOP side and again this piping is really not in the scope of license renewal, we did have a couple of failures on our EHC return lines from our main turbine control valves.

We did, as I mentioned before, do uprate in a two step fashion. So after our initial uprate at an intermediate power level, our main control valves were not in their final position, design position. So we did get more movement than you would normally expect at that power level. There is quite of bit of industry OE with failures of this line and again it is a socket weld type connection and we have since modified that piping to get a flexible connection design.

As I mentioned we did have a number of failures on socket weld type joints. This was primarily around our feedwater heaters. Again, we've had a lot of previous operating experience prior to uprate. We did go in to susceptible locations and change the joint design for that socket weld to a more fatigue tolerant configuration.

We also went through and did pretty extensive walkdowns on our BOP piping at all power levels up to 120 percent as part of uprate. We did identify a couple of BOP lines, on extraction steam line and a small bore main steam line that or main steam drain, excuse me, that were exhibiting some very low frequency vibration, low frequency movement. All of that piping was rod-hung piping. There was no lateral support and we did go in and add lateral supports to those.

MEMBER MAYNARD: What has the feedback been from the operators, if any, in their plant walkdowns? Do they hear more noise in some of these areas or have they identified any areas you've had to go look at?

MR. GRANTHAM: None that I can recall and again, following the uprate we went through a pretty extensive test program and we had hold points at the various power levels as we went up and we had engineering walkdowns, operation walkdowns and we had management review at each of those hold points. So nothing out of the ordinary was reported or observed.

VICE CHAIRMAN SHACK: Is your FAC experience after the uprate consistent with what you would expected from the uprate?

MR. GRANTHAM: I'll be quite honest. We're still developing that. We got data following this past outage which we had one year of operation. The data did not show anything out of the ordinary, but I'm not sure just a two year operating cycle is enough really to completely get a good idea of what you're seeing. But we are monitoring it. It is very much an inspection based program. We rely heavily on inspections and less on predictions from our check-works models. Any other questions on vibration before I move on?

All right. Next we're looking at major equipment replacement and repairs. Again, this is over really about the last four years. Some of these were related to uprates. Some were not. We have replaced our power range neutron monitoring system, the complete system, replaced our main power transformers, replaced our high pressure turbines. We reround our main generator statters. We've replaced six feedwater heaters, five on Unit 1, one of Unit 2. We've replaced our reactor feed pump turbine.

VICE CHAIRMAN SHACK: Why did you replace those?

MR. GRANTHAM: It's primarily tube plugging, looking at the higher flows associated with uprate. We did an assessment of all our feedwater heaters in accordance with the HEI standards as far as flow, pressure drops and some of those heaters we would have replaced even without uprate, the tube plugging. One of them we had, I think it was up on the order of 18 percent tube plugging. So some of them would have been replaced anyway.

VICE CHAIRMAN SHACK: What was the original material?

MR. GRANTHAM: I believe it was 410 stainless steel. Reactor feed pumps, we installed new governors on our reactor feed pumps as well as replaced the pump rotating assemblies. We replaced our condensate pumps and motors. We completely replaced our isophase bus cooling units and we're currently about halfway through a major project to completely replace our fire detection system, new sensors and everything. Any questions?

All right. With that, I'll turn it back over to Mike Heath.

MR. HEATH: Thank you. I want to talk now about exceptions to GALL. When we prepared the application, our goal was to comply with GALL in every place that we could. There are some cases where existing programs satisfy our program needs and we'll be discussing a few of those here.

For fire protection program, NUREG 1801 calls for a visual inspection of ten percent of each type of penetration once every refueling outage. Our existing program at Brunswick has us doing visual inspections of a statistical sample once every 18 months.

GALL also calls for testing of halon and CO_2 every six months. At Brunswick, we do testing of halon annually and we test CO_2 every 18 months.

For fuel oil chemistry, GALL calls for internal --

MEMBER POWERS: There must be a rationale for those times.

MR. HEATH: That's based on our own operating experience in the plant. Six months. We're talking about the halon and the CO_2.

MEMBER POWERS: Right.

MR. HEATH: Yes, the halon and CO_2 every six months, we've had no experience that we have any problems in that system and that seems to be a very reasonable time for us.

MEMBER POWERS: So it's chosen because it's convenient. I mean if there are no problems might as well do it every five years. Right?

MR. HEATH: Well, you try to get the most optimum time period on those. There are some things that you can't even look at because of your outage frequency. This would not be one of those cases. But you're still looking at those things on an optimum basis. We see no value in doing it less than that and our current operating experience suggests that's a pretty good number.

MEMBER POWERS: What was the rationale for the NUREG that called for every six months.

MR. HEATH: I don't know that.

MEMBER POWERS: It seems extraordinarily frequent.

MR. HEATH: I know there's been a good bit of discussion about changing that, but I'm not sure what the rationale was.

MEMBER SIEBER: It seems to me that the six month interval was inconsistent with what the fire insurance companies were requiring which was annual tests.

MEMBER POWERS: I mean it does -- Six months sounds very, very frequent.

MEMBER SIEBER: Yes, especially for halon. Halon, you aren't supposed to be playing with halon.

MEMBER POWERS: Well, you could understand for halon just because of the halon corrosion potential that you do have there. But I mean it just sounds enormously frequent.

MEMBER SIEBER: Yes.

MEMBER POWERS: I mean 18 months doesn't

sound an extraordinarily cavalier time either especially if you've had no difficulty there. I'm just wondering what the rationale was and it sounds like in your case it's convenience.

MR. HEATH: And it's what we've been doing all along.

MEMBER POWERS: Yes. I mean if it's what you're used to, no reason to change it.

MR. HEATH: Right.

MEMBER SIEBER: Okay.

MEMBER BONACA: And what's the basis for the requirement in NUREG 1801? Maybe the staff could comment on that.

MR. MITRA: This is SK Mitra. This issue was addressed by the staff and as already remembered, there was an RAI on this and I don't have the staff, the engineer, who did the review, but as far as I remember, this issue is not unique for Brunswick and this being raised and as a matter of fact, there is an, I say, action item to change the six months inspection to 18 months. But I am not quite sure how far that went.

MEMBER POWERS: If there's no rationale for six, is there a rationale for 18?

MR. MITRA: That's the industrial

standard. That's what most of the plants are doing is 18 months.

MEMBER BONACA: One of the issues that during the past review of 1801, one of the goals was to reduce or eliminate prescriptiveness which is unnecessary because otherwise you have these kinds of disagreements that are not a disagreement really and maybe that was not implemented.

MR. CHAN: This is Keng Chan from License Renewal. The GALL specified an acceptable alternative of addressing those issues. Like six months is acceptable. But GALL does not exclude any applicant using the plant-specific experience or reasoning to deviate from the six months or basis. It tends to be a little conservative, but I cannot answer the question regarding to whether the GALL will be modified to increase.

MEMBER BONACA: But if everybody does it every 18 months, assume every plant does it every 18 months and it's acceptable.

MR. CHAN: Yes.

MEMBER BONACA: Why would you have a requirement for six months when you have no basis? I mean you would look at the experience, determine that 18 months is appropriate because it doesn't seem to create a problem and simply modify GALL to reflect 18 months. I think otherwise you're going to have exceptions like this which are really not relevant and require additional RAI and every time a discussion of the discrepancy when you don't need that.

MR. CHAN: Yes. As I said, I cannot tell you exactly whether we are changing it or when we are changing it. But certainly we include that in our GALL update maintenance program for future considerations.

MEMBER KRESS: What would you say if someone wanted to have a 36 month inspection schedule? How would you judge that?

MEMBER BONACA: Well, I think the only thing that I can say is that there has been so much operating experience behind these plants and some assume that most of them do it every year or 18 months and that seems to be an appropriate frequency. I think you would just leverage the experience because you have no other basis.

MEMBER POWERS: It looks like to me that it's just a completely arbitrary experience.

MEMBER ARMIJO: Is there a failure rate for these things built into the fire PRA?

MEMBER POWERS: It seems to me that

there's just a huge number of these systems operating throughout the United States and surely there is some basis for deciding how often they ought to be inspected or tested or something with that.

MEMBER KRESS: It would have to be how often they're inoperable or not functioning properly.

MEMBER POWERS: Something to do with their failure mode I would think and any number that comes up -- I don't object to the plant saying we do it every 18 months and they have no difficulty. That's great.

MEMBER KRESS: That could give you a basis.

MEMBER POWERS: But the staff recommendation for six months seems or 18 months or 36 months, any number that's pulled out of the air seems to me just completely capricious and arbitrary and it's going to generate this kind of --

MEMBER KRESS: Unless there's a fire PRA with a failure rate built into it and that's based on the 18 month inspection because that's the operating experience.

MEMBER APOSTOLAKIS: The same question you can raise about any inspection interval, right, that has been established in other context and that's why there are risk-informing regulations to try to come up with a more rational way of determining those things. So this is not unique.

MEMBER POWERS: No, it is not unique, but it is certainly a good example.

MEMBER APOSTOLAKIS: Yes.

MEMBER KRESS: George, so long as the failure rates you build into the PRA are consistent with the inspection period, wouldn't that be sufficient unless these things dominate some.

MEMBER APOSTOLAKIS: Or you could go the other way. You determine the inspection frequency from the PRA calculation.

MEMBER KRESS: That's hard because you have to link inspection frequency to failure rate.

MEMBER APOSTOLAKIS: Right.

MEMBER KRESS: And you don't have that database.

MEMBER POWERS: It don't see why you can't get it, Tom.

MEMBER APOSTOLAKIS: They do.

MEMBER POWERS: I don't see why you can't get it. This is --

MEMBER KRESS: It may be possible, but it seems to me like the consistency argument is a lot easier to come by.

MEMBER POWERS: I can understand why you would have the consistency argument, but you have a bit of "the chicken and the egg" problem here.

MEMBER KRESS: Oh, yeah.

MEMBER POWERS: Is like George says. This is a system where you would like to use the PRA to tell you how often to inspect something.

MR. KUO: This is PT Kuo. I believe this fire protection issue was an IC topic. We have an issue in IC and I'm not totally sure if this is the requirement of NAPPA (PH) and we are going to take a look into that. There has to be some basis. I don't think the staff will make a requirement without a basis, but I'm not sure whether this is a NAPPA requirement or not. But it was in IC.

MEMBER SIEBER: Okay.

MR. HEATH: Okay. The other exception we had involved internal surface inspections for main fuel oil tanks. We have committed to doing internal surface inspection for our main oil fuel tank. That's the only fuel oil tank we have that's accessible to the internal surfaces. When we do that inspection if we need to, we'll clean the tank as well. Our smaller tanks we've committed to doing UTs at that bottoms of those tanks from the outside.

MEMBER SIEBER: I take it an example of a smaller tank would be like the day tank on these.

MR. HEATH: It would be the day tanks. Yes.

MEMBER SIEBER: Okay, and these just sit in the air.

MR. HEATH: They sit up in the air and the bottoms are accessible for us.

MEMBER SIEBER: Okay.

MR. HEATH: We move on then to commitment tracking. We commit, we do, our tracking for license renewal commitments the same way we do our tracking for all other commitments at Brunswick and that's using our corrective action program. The one exception we have for license renewal commitments is that we've developed an implementation plan for each of those and that implementation plan then identifies everything that we have to do to implement that commitment.

All those actions, if it's a procedure change or the writing of a PMR or a work ticket, are tied back then to that commitment through the corrective action program. Each of those actions has an owner and each one of them has a date for completion.

We also are in the process of developing a license renewal program procedure. That procedure then lists all those individual activities. So it lists each commitment and all the procedures and PMs and work tickets and other action items associated with it and we'll do periodic assessments of that procedure to assure that all of those activities are being completed in a timely manner and are still effective.

We are currently planning to complete all those document updates that we can this year. We expect to complete most of them prior to the end of this year. Any questions on commitment?

If there are no further questions, I would like to conclude just a few comments on the review auto process. At Brunswick, we found that to be very effective. It was to our advantage to have staff onsite early in this process. We came to learn what the problems and concerns were and we were able to identify those very early in the process and we think that contributed directly to the SER coming out with no open items and no confirmatory items. Are there any other questions for us?

MEMBER SIEBER: Yes, I do have a question.

MR. HEATH: Yes sir.

MEMBER SIEBER: When I read the application and the SER and look at the NRC's website, I hear different names for your company and I'd like to know who is, what is the name of the entity that holds the license. Is it Carolina Power and Light or Progress Energy Carolina or what?

MR. HEATH: I'll Lenny Beller, our Licensing Supervisor, to give you the complete and true answer on that.

MEMBER SIEBER: You could just whisper it to me if you'd like.

MR. BELLER: Good morning. My name is Lenny Beller. I'm the Licensing Supervisor. Carolina Power and Light is the holder of the license. Progress Energy is the parent company. But Carolina Power and Light is the entity that owns that license.

MEMBER SIEBER: Okay. Thank you and Tanny was right. Okay/

MR. HEATH: Any other questions? Thank you.

(Discussion off the microphone.)

MS. LUND: Okay. At this time, we're going to do the staff's presentation and it's going to be SK Mitra and Maurice Heath that are going to be making the presentation for the staff.

CHAIRMAN WALLIS: You're not related to the other Heath? There's a Heath on the other side, too, isn't there?

MR. MITRA: Good morning. I'm SK Mitra. I'm the Project Manager for the Brunswick Steam Electric Plant Units 1 and 2 license renewal application. To my right, Mr. Maurice Heath, Project Manager, who helped me to prepare and issue the SER report and from now on I think he will be the project manager because I am going and working on some other projects.

As we mentioned before, Mr. Coudle Julian is on the telephone line. He's listening to us and if you have any question on inspection, he will be glad to answer that. Also present in the audience are the technical reviewers, most of them. I could find my fire protection engineer there, but most of them are there who contributed to the ACRS to answer any questions regarding the evaluation.

This is what we'll cover in this presentation. I will just skip this because already the Applicant had gone through that. So go to the next slide. Each unit generates 2923 megawatt thermal which is about 1007 megawatt electric. That includes

20 percent extended power uprate. The NRC approved five percent power uprate in 1996 and an additional 15 percent on May 2002 and steam dryers by the way are within the scope of license renewal.

The second bullet, the Applicant committed to review plant and industry operating experience relevant to aging effect caused by operation at power uprate. The revelations will be submitted to NRC review one year prior to the period of extended operation. This is a direct result of the commitment made in response to SER letter of September 16, 2004, on license renewal application on Dresden and Quad Cities.

The SER was issued on December 20, 2005 and as the Applicant said, there was no open-end confirmatory items and also I acknowledge that the staff's audits and inspections helped us resolve a lot of issues and we issued the final SER on March 31, 2006. And it's the usual 3 license condition we have that the FSER update following the issuance of renewed license and commitment completed in accordance with the schedule and the third one is the reactor vessel service (PH) program and implement staff approved BWR/VIP into the vessel service (PH) program and obtain the NRC staff review and approval for any changes to the schedule.

CHAIRMAN WALLIS: There are no conditions on the liner for the containment.

MR. MITRA: No.

CHAIRMAN WALLIS: You are satisfied about the bulges and all that.

MR. MITRA: The staff is satisfied with the bulges and all that. And these are the few items, the components, that bring into the scope and subject to MR was switchyard breakers. You know these are the result of the review. Service order intake structure fan, dampers and condensate storage tank piping created for SBO station blackout.

This is the first time on Brunswick license renewal review the staff has used the balance of plant scoping review for two-tier process. The staff presented this concept to SES (PH) full committee on March 4, 2005 and explained the review process at that time and essentially the two-tier process, the Tier 1 is the screened review of the license renewal application FSAR and identify system for inspection.

Tier 2 review is slightly more detailed than Tier 1 review. Tier 2 review concerns the review of boundary drawings, other licensing basis documents in addition to the application and FSAR. Typically, the other licensing basis documents including plant specific licensing action like relief request, etc.

And two-tiered scoping will be based on screening criteria, mainly safety importance and risk significance. Systems susceptible to common cause failure, operating experience indicating likely passive failures and previous LRA experience of omissions and all electrical system and structure continue to have Tier 2 review.

And groundwater environment is all under the limit and this groundwater monitoring is done at a frequency of annually. I think the next few slides will be done by Maurice.

MR. MAURICE HEATH: Yes. Good morning. Like SK said, my name is Maurice Heath, Project Manager also with him on this project. What I want to go over is just a brief highlight of a couple changes or additions, not changes, additions, to the SER from the first SER to the final SER.

The first highlight I want to go over deals with Commitment No. 22 and that is with Reactor Vessel Internal Structure Integrity Program and we added -- There was additional information added to the commitment based on top guide inspection and what we want to do is just lay out the same information that was written in the SER and put in the commitment as well so that it's a clear understanding of our sample size and our inspection frequency.

The next one I would like to go over would be the Applicant already did with Mark 1 steel lined reinforced concrete containment. The Applicant credits the Section 11 IWE along with the Part 50 Appendix J to manage the drywell liner. Both the IW and Appendix J requires 100 percent inspection per period and --

MEMBER BONACA: There are three period inspections. Is that right?

MR. MAURICE HEATH: Yes, it is.

MEMBER BONACA: So that depends on the bulges.

MR. MAURICE HEATH: Yes, it does. So based on the history and the current programs that the Applicant uses, it gives confidence to the staff that they will effectively manage the drywell throughout the period of extended operation.

The next slide I want to discuss was the TLAA and based on the reactor vessel and upper shelf energy and this was a lessons learned from the subcommittee meeting and the question from the subcommittee meeting was conclusions. They were not clear in our Section 4.22. So from the lessons learned from that, we took that and took our chart that we presented and actually put that in a final SER so there is more of a sequence and you can follow the conclusions and as you can see, we have our acceptance criteria and then we have the calculations that the staff did for the 54 EFPY and then the accepted and the reason why which guidance it follows. It's acceptable with I, II, III and that is also shown on the next slide.

With that, I want to conclude as for the staff presentation and on the basis of this evaluation of the license renewal application, the NRC staff concluded that the requirements of the 10 CFR 54.29(a) have been met. With that, I would like to open it up to any questions from the members.

MEMBER BONACA: So I understand now the issue of relying purely on the visual for the liner is based on the fact that they cannot get water during refueling between the liner and the concrete. Right?

MR. MITRA: Yes.

MR. MAURICE HEATH: Yes.

MEMBER BONACA: Okay. So I understand this is becoming an ISG and so the condition is different. However, you're going to still require ultrasonic testing. So this is the basis. In this particular design, you have concluded that you don't have moderate penetration.

MR. MAURICE HEATH: I'll get Hans actually to address that.

MR. ASHAR: ISG is presently --

MR. MITRA: Hans, please identify yourself.

MR. ASHAR: Oh. Hello, I am Hans Ashar. ISG specifically excludes the application to the Brunswick, just one plant, because there is reinforced concrete steel liner on it. ISG applies to all the other Mark I containments.

Now in the case of Brunswick, I'm aware of everything that Tom Overton spoke to you about, all the three holes that he had experienced we had followed them through our inspection because every time something happened, the Region II inspector had called me up, I know and at that time, we had talked about the three holes that they found, one hole from the other side and everything. We talked about it. We imposed certain more requirement on the Applicant, at that time licensee. It was on the current licensing basis.

So I'm aware of, but in general, there is a lot of discussion here about the bulging and it is true that a number of PWRs with liners as thin as quarter inch liner and they are bulging between the anchors which starts anchoring to the concrete and they are bulging between the two and it's not really unusual to find that kind of a thing.

In case of prestressed concrete containments, it is not happening as bad. It generally should happen bad, much more robust than that because of the creep and shrinkage of concrete that would influence the bulging. But what happens in the construction with the wisdom of the engineers, they had put the T sections or angle sections on it so that the bulging is almost not there in many of the prestressed concrete containments.

But in reinforced containment, you will see bulging a number of places just because of the dead load and the shrinkage that is caused between it. Any other questions on that?

VICE CHAIRMAN SHACK: No thank you.

MEMBER SIEBER: Maybe I could make a comment because the containment design in this plant has been a concern at least to me and others in the staff and my way of looking at it is that this Mark 1 containment differs from all the others in that the steel liner is not a structural member. It's just a member to prevent leakage in the structural of the concrete and the reinforcing bars and so forth. So it holds a different status than all the other drywells in Mark 1 containments in where the liner is the structural entity there and of course, it's two and a half times as thick.

So it seemed to me based on what I know about large dry containments that are steel lined concrete and leak tightness that the kind of inspections that are proposed and that have been done are reasonable and consistent with what one would do with a large dry containment that's basically a doomed cylinder. Otherwise, I think if it were actually the strength member of the containment as opposed to just a barrier to leakage, I think the concern would be quite a bit different and greater.

MEMBER MAYNARD: It also appears to me that even if there was some localized corrosion that even through-wall you really haven't lost the containment function. The concrete failures still have compressor retaining capability there.

MEMBER SIEBER: And you're right. You do and, in fact, I'm reviewing right now the containment tests that Sandia and others did which shows some interesting results in failures of large dry containments. They don't just fall apart. They just start to leak. In this case, at the design conditions, the limiting factor would be the Part 100 leakage limits in an accident and that's the integrated leak rate tests are designed to show. So I come away from the review and everything that everyone has done, both the Applicant and the staff, with the conclusion that the aging management program which was proposed is adequate for this application.

Are there any other questions?

MEMBER ARMIJO: I have a couple of questions on the table on the reactor vessel upper shelf energy. Yes, that first row there, the calculated value or analyzed value for the drop in the upper shelf energy comes out to be 21 percent as opposed to an acceptance of 23.5 percent. That's pretty close.

What I'd like to ask is does the staff do independent calculations or analyses to come up with, to verify that the Applicant's numbers are right. What happens if it turned out to be 24 percent? Is that the end of the world? How close are we to --

MR. MAURICE HEATH: I'll get Jim Medoff to address that.

MR. MEDOFF: This is Jim Medoff with the Division of Component Integrity. At the time of the review, I was working for the Vessels and Internals Integrity branch. I was responsible for doing all the time limiting aging analyses on neutron radiation embrittlement including those for the upper shelf energy assessments.

Yes, we do do independent calculations, but before we do anything, any independent calculations, we make sure that the neutron fluence methodology and the values provided by the Applicant are reviewed by Dr. Lambrose Lois of the Division of Safety and Safeguards. They renamed it, but it's basically the Systems division and he's in what used to be the Reactor Systems branch. He's our expert on neutron fluence methodology. So I get his approval of their values and then we use the values, if he approves them, we use the values provided by the Applicant in their applications and we compare our values to their values.

MEMBER ARMIJO: So those would be the fluences on the next chart.

MR. MEDOFF: Well, no.

MEMBER ARMIJO: For forging.

MR. MEDOFF: The reason there are two slides is for the upper shelf energy and equivalent margins analysis. For the reactor shell plates and shell welds, we used the VIP guidance. But they had a commitment to do a plant specific equivalent margins analyses for their nozzle forgings and so I think it was in '99, I evaluated that and approved that equivalent margins analysis for the nozzle forgings and I think we approved them down to about 30 foot pounds.

For the FTLA, they had to just either demonstrate that the fluence was still bounding or that the recalculated value would remain above 30 foot pounds and they chose the former approach. I had had an oversight in not doing the welds. So we corrected that for the license renewal application. So for the nozzle welds, we used the generic VIP criteria to do the equivalent margins analysis.

MEMBER SIEBER: Any other questions? I think before we close I would point out to both the staff and the Applicant that in my review of this application and the accompanying SER I came away from it, from that review, as concerning both the Applicant and the staff to have done a really good job in putting together the application that was concise and direct to the point and a safety evaluations report that that was very well done.

I would think that there is a learning curve in license renewal applications and there obviously is and this is the result of maturity of that learning curve. But I also think that both the staff and the Applicant did a good job of being conscientious and paying attention to the details to get it right the first time. So that's my personal opinion. I think that both the Applicant and the staff did a good job on this.

If there are no further questions, I appreciate the presentations by both and, Mr. Chairman, I'll give the meeting back to you.

CHAIRMAN WALLIS: Thank you. We've continued our tradition of being ahead of time.

MEMBER SIEBER: You can count on me, sir.

CHAIRMAN WALLIS: We're not allowed to start ahead of schedule with the next presentation. So we will take a break until 10:15 a.m. Thank you very much.

MR. MITRA: Thank you very much. Thank you, Dr. Sieber. I took the compliment on behalf of the staff and I am sure that the Applicant also appreciated your comment. Thank you.

MEMBER SIEBER: Thank you.

CHAIRMAN WALLIS: Off the record.

(Whereupon, the foregoing matter went off the record at 9:42 a.m. and went back on the record at 10:15 a.m.)

CHAIRMAN WALLIS: On the record. Please come back in session. Next on the agenda is the Final Review of the Extended Power Uprate Application for R.E. Ginna Nuclear Plant. I invite my colleague, Rich Denney, to lead us through this one.

MEMBER DENNING: All right. The request here is for 17 percent power uprate. We've had three subcommittee meetings. A focus of a lot of our concern had to do with margins and so you'll see quite a bit of discussion of that. I will point out that as I look at the number of view graphs that are planned for presentation here and I mentioned this to Mr. Milano is there are just too many and so we're going to have to move. It would be okay if we didn't have an advisory committee, but the advisory committee is going to ask questions. So if I see us getting delayed in areas that don't seem to be important, I'll try to press you. So I then turn it over to Mr. Milano to make the preliminary introductions.

MR. MILANO: Good morning, Mr. Wallis and other members of the ACRS staff. We're here today as Mr. Denning said to review the 17 percent extended power uprate for the R.E. Ginna Station and the Constellation Energy's safety assessment of the uprate and the staff's evaluation of that.

Again, my name is Patrick Milano. I'm the NRR Licensing Project Manager with responsibilities for the Ginna Station. Today Constellation, the key members of the Constellation team are Mr. David Holm, the Plant Manager for the Ginna Station and Mr. Mark Finley who's the Project Director for the uprate.

Just quickly, these are the basic topics that both Ginna and the staff are going to follow and in the interest of time, I'm going to go without going through these to try to explain any of this stuff. I'm going to turn it over to Mr. Holm who is going to going to start the presentation for the licensee. Thank you.

MR. HOLM: Good morning. On behalf of Constellation Energy, we're very pleased to present our application for power uprate this morning. With me today in addition to Mr. Finley, the Project Manager, we have Roy Gillo (PH) who is an Operations Shift Manager. From our Engineering Services Department, Gord Verdin, Jim Dunne and Joe Pacer, our

PRA consultant, Rob Cavedo, our Licensing Engineer, George Wrobel and a host of Westinghouse support. I'm going to provide some brief facts about the Ginna Station and then I'll turn the presentation over to Mr. Finley.

Ginna is a Westinghouse, 2-Loop pressurized water reactor 1520 megawatts thermal by design. The plant initially started commercial operations in 1970 and was originally licensed at 1300 megawatts. However, in 1972, the license was increased to the original design power of 1520 megawatts. In this application we seek to raise the thermal wet megawatt rating to 1775 megawatts. Of note, the Kewaunee station which is a very similar NSSS design to Ginna Station uprated approximately two years ago to 1772 megawatts and has been operating successfully over that period of time.

Some of the activities that have led up to this application, in 1996, Rochester Gas and Electric replaced both steam generators at the Ginna Station. Those steam generators were oversized in anticipation of and to leave the options for a future uprate. In 2003, the reactor vessel head was replaced, thus, eliminating any Alloy 600 concerns. In 2004, shortly before Constellation Energy closed on the purchase of

Ginna station we put together an experienced project team consistently of not only Constellation Energy engineers but Westinghouse, Stone & Webster and Siemens.

Throughout that period of preparation, we have had an executive oversight committee providing a challenge process consisting of Constellation Corporate, vendor representatives and industry experts. We are prepared to implement the modifications, testing and operating procedures necessary for this uprate in our October 2006 refueling outage.

Mark Finley will now review the major modifications, plant parameters and license changes to implement this uprate.

MR. FINLEY: Thank you, Dave. Good morning. My name again is Mark Finley and I've been at Ginna now for about two years and three months as the Project Director for the power uprate. Before that, I was at Calvert Cliffs for 19 years and worked in the Licensing, Outage Management and most recently in the Fuel and Safety Analysis area. So after I talk about the plant changes, I'll also talk some about the safety analysis and again there's a lot of material there. So I'll really leave it up to the Committee if you have questions and then we'll spend more time in those areas.

First, I'd like to talk about the operating parameter changes that we're going to go through to implement the uprate and then I'll talk about the major modifications and the license amendments.

With respect to the plant parameter changes, this is a busy slide here, but one of the learnings we took away from the meeting that you all had with Waterford was to show you how we're actually achieving the power uprate and if you look at the top line here, it shows the power change, the core thermal power change, from 1520 megawatt thermal to 1775 megawatt thermal. That's actually 16.8 percent.

Of note is we're increasing the average coolant temperature from 561 degrees to 574 degrees. However, that's not a temperature that Ginna hasn't seen in the past. Before we replaced steam generators in 1996, we actually operated as you see in the footnote there at 573.5 degrees. So we're actually going back to an average coolant temperature similar to what we had before we replaced steam generators and of course, the reason for the increase in average coolant temperature is to increase the steam generator pressure to provide a higher pressure at the main turbine inlet.

Also of note on this slide is if you look at the coolant mass flow, there's really no change or a minor change in the coolant mass flow rate. It actually decreases slightly 0.7 percent. The volumetric flow actually increases slightly. But why that's important is essentially the way we're getting the power is with a constant flow in the reactor coolant system we're increasing the core ΔT, increasing the heat out of the fuel and increasing the core ΔT. That's how we're getting the power.

With respect to the major modifications to implement the power uprate, before I go down the list, I'd like to just state that our design objective throughout for these modifications was to maintain the overall reliability and safety of Ginna and that was the basis for driving these modifications. As an example, we're maintaining the number of installed spare pumps and fans in the plant to maintain that level of redundancy and again reliability.

The first two modifications there are safety related modifications. The remainder of the modifications on the list are balance of plant modifications and this is just a reflection of what

Dave Holm said earlier about the Kewaunee plant, a sister plant of Ginna with a very similar NSSS design. They've uprated to 1772 megawatts thermal and our NSSS is very similar to theirs and really no need to make many modifications to the NSSS or safety related systems with the exception of the fuel assembly. We are incorporating the standard updated Westinghouse design fuel assembly, the 422 V+ design with slightly longer rods and fatter pellets that allows us to get the additional uranium in the core that we need for the uprate.

The other significant safety related modification is we're adding an actuator to manual main isolation valves in the feedwater system and these valves will close automatically on a safety signal and stroke faster than our current backup valves do. It provides additional margin for steam line break analysis for containment response.

In addition to that, we have these balance of plan modifications, most significant of which is we're replacing the high pressure turbine rotor. That's, of course, to get the additional flow past through the high pressure turbine and the power out of the turbine. We are replacing the main feedwater pump impellers and main feedwater pump motors, in addition replacing the condensate booster pumps and booster pump motors. We're upsizing those pumps, of course, to handle the additional flow and also replacing the feed regulatory valve and the bypass valve internals associated with that feed regulating valve.

In terms of the electrical side of the system, we are increasing the cooling for the main generator. We're replacing a heat exchanger that provides the cooling water to the hydrogen coolers on the main generator again to remove the heat that's associated with the higher electric current passing through the generator.

For the main step-up transformer, we replaced the high side voltage bushings and added a fifth cooler bank. Another example of our design objective to maintain the same level of reliability and redundancy, we currently have four cooler banks on the transformer. We could have done the uprate with just those four, but we would not have had an installed spare on that transformer. So we're going to add the fifth cooler bank to maintain that level of redundancy.

And for that isophase bus duct, we're adding a third fan, again to provide the additional installed spare for that system and for the underground oil cables that transfer the power from the plant to the switchyard, those are oil-filled cables, we're going to recirculate that oil. Currently, it's a static system and we're going to just dynamically recirculate that oil as part of the uprate.

For the moisture separator reheater relief system, we're making modifications there again to handle the higher steam flow rates. We need additional capacity through this relief system.

And last but not least, we did learn through our PRA process and Rob Cavedo will speak to this in more detail when he talks about PRA, we took some good learnings away from that process that we then factored back into the design plans for the uprate and examples of that are we're going to add a system to back up the normal air supply to the charging pumps such that if we lose our normal air supply, we have a backup. We're also adding some additional controls for the charging and turbine-driven aux feedwater pump and this will enhance operator response to fire scenarios. Again, this was a learning that we uncovered from the fire portion of the risk evaluation.

I won't spend a lot of time with this

slide, but this is a listing of the license amendments that we have submitted to the NRC. Several of these have been approved already, but we did obviously need to increase the license core thermal power. We are changing our LOCA methods to the updates best estimate LOCA methodology from Westinghouse. We'll revise the actual offset control method to the standard updated Westinghouse relaxed actual offset control design.

We need to increase the boron concentration to provide additional ability to have more boron in the RCS for reactivity holddown. A minor change to the accumulator volume, that's really not driven by the uprate, but we wanted to get some margin to the uncertainty analysis for the accumulator level indicator. Condensate storage tank volume increase that slightly. Basis for that volume in the tank is remove at least two hours of decay heat.

CHAIRMAN WALLIS: This is the volume of water, not of the tank and the accumulator.

MR. FINLEY: That's correct.

CHAIRMAN WALLIS: You haven't changed anything. You just put more water or less water in.

MR. FINLEY: That's correct. They have not modified the tank, just raised the minimum required level.

And the feed isolation valve that I mentioned, the stroke time for that valve is an improvement. It will be 30 seconds in the technical specifications as compared to 60 seconds currently. And there were some changes to other RPS and engineering safety feature set points and I'll mention those later. Any questions about the plant changes, modifications or amendments?

MEMBER MAYNARD: Just real quick on feed isolation valve you say the tech spec will say 30 seconds. In practice, what do you expect the close time to be?

MR. FINLEY: Okay. The question is the tech specs will say 30 seconds. We expect -- We're purchasing the valve with a specification of less than 25 seconds and we expect the valve will stroke in the 15 to 20 second range. Other questions?

Okay. I'll move right into safety analysis where I'm going to talk about the safety set point changes like I mentioned. We factored in some new control settings. We optimized control settings. And, of course, you have to factor that into the impact on the safety analysis. I'll talk about the methods that we changed. I'll talk some about non-LOCA where a significant amount of discussion was had at the subcommittee meetings with respect to margin and briefly discuss LOCA results where there's more margin and then talk about the long-term cooling analysis for Ginna and there was significant discussion there again at the subcommittees.

First with respect to the safety set points that were changed and these again are controlled by the technical specifications, they're also the analytical set points used in the safety analysis. Of course, as you know, these are bounding with respect to the actual field set points. We did lower the high flux trip set point as a percentage of the full power from 118 to 115 percent. Both the high-high steam isolation and the high steam isolation set points associated with the engineering safety feature systems were increased to account for the higher steam flow rates.

Pressurizer safety lift setting was reduced slightly two pounds there, not a big change, but necessary for the acceptable results in the safety analysis. Safety injection and containment spray, the set points there, the second and third from the bottom, those are small changes, not really required again by uprate but changes that we wanted to make while we were revising the safety analysis to provide additional margin in the uncertainty calculations done for those set points.

And at the bottom there, that PA permissive set point, that's the set point below which we can operate with a single loop and we don't, our operating procedures don't actually allow us to operate single loop, but we have a tech spec set point for single loop operation and that was lowered from 50 percent to 35 percent.

Again, not to spend a lot of time on the control system settings, but just to give you a flavor for how the control grade system settings were changed and the fact that these were all factored into the safety analysis, pressurizer level range from hot zero power to hot full power was increased. The new EPU settings will be 20 percent to 56 percent. As compared to before, we had a range of 35 percent to 50 percent.

Obviously, the reason we had to do that is now our full power T_{Avg} is higher than the zero power T_{avg}. So the increase in temperature as you come up from zero power to full power now is greater. You have to allow for that in terms of pressurizer level change say for a trip and post trip change in temperature. So that's what we did with pressurizer level. And I mentioned $_{Tavg}$. The program T_{Avg} changes now to get us to the higher T_{Avg} at full power.

We optimized the settings on both rod control and steam dump. These are the control systems that would guide the plant for power mismatch scenarios automatically. And at the bottom there, we are adding a filter on the T hot indication signal and the reason there as other plants have seen, other pressurized water reactors have seen, we have small oscillations in indicated hot light temperature and putting this filter on that signal dampens out those oscillations. It provides a more steady signal.

MEMBER SIEBER: Have you ever gotten a trip from spurious T hot signals?

MR. FINLEY: The question is have we ever gotten a trip from spurious T hot signals? The answer is no, not to my knowledge. We have gotten alarms such that we know the margin is not what we want it to be, but no automatic plant trips.

MEMBER SIEBER: Okay.

MR. FINLEY: With respect to the methods used in the safety analysis, the non-LOCA analysis were performed with the RETRAN code not new to the NRC, just new for Ginna in the non-LOCA area. We had previously used LOFTRAN. In addition, along with

RETRAN we changed the thermal hydraulic code that's used as part of these analyses to the VIPRE Code. That's just the most recent analytical method that Westinghouse uses for DNB. We previously had used the THINC Code coupled with LOFTRAN. So that's part and parcel to the RETRAN change.

I mentioned previously for large break LOCA we updated to the most recent best estimate LOCA methodology. For small break LOCA, there was no change in method. We use the NOTRUMP Code previously and use that for EPU. Similarly for the control system transients, we continue to use LOFTRAN for that.

For the containment analysis, we previously used the GOTHIC Code for the LOCA response. We continue to use that for EPU. However, for steam line break, there was an older method call COCO Westinghouse methodology. We've updated that now to GOTHIC, the newer containment analysis method.

And for the dose assessment area, actually in 2005, we gained approved of the alternate source term methodology. That was done prior to EPU. We also upgraded our control room ventilation system at that time. So no real significant changes to the dose methodology or to the way we operated the control room ventilation.

As I mentioned, we'll talk in some more detail about the non-LOCA analyses that were done and in particular, about the margin in these analyses. But before I do that, I'd like to talk about the approach that was used at Ginna as a backdrop to that. First of all, a very conservative inputs, essentially the same inputs that were used in the pre-EPU analyses, we attempted to stick with those, where possible, for the analyses done for the EPU.

However, here were certain limiting EPU analyses that weren't successful with those very conservative inputs. We, therefore, adjusted the inputs, in other words, constrained our operating windows with more restrictive inputs until we achieved successful results for the limiting analyses. But we didn't attempt to demonstrate additional margin beyond that point. So several of the results as you'll see in the next slide are close to the acceptance limits based on this approach. But we do understand that there's a large amount of conservatism not only in the methods and the inputs that are used but also in the safety limits that we're required to meet by the approved NRC methodology.

And this is the slide that Dr. Wallis

specifically asked that I bring back to the full committee. So, Dr. Wallis, dutifully I'm leaving this slide in the presentation. But this shows the limiting non-LOCA events for Ginna and categorized as overheating, overcooling and reactivity addition. But this demonstrates the point that I brought out previously that some of the results are close to the criteria although they are acceptable and I'll walk through an example here in a minute just to demonstrate why this is acceptable and what the additional margins are in the analysis to make us feel comfortable that this is safe.

As you can see for the overheating events, loss of flow and locked rotor, those are the reduced primary cooling events and the results that they have, i.e. DNBR of 1.385 for the result with the criteria being 1.38. I'm going to talk about that one in more detail in just a second. Overheating events where we have reduced secondary side cooling include the loss of load in the feed line break analysis and those demonstrated acceptable results.

On the over cooling side for the steam line break or the condition four event, again we demonstrated acceptable results for DNBR and linear heat rate. And for reactivity addition, the most limiting events were the rod withdrawal at power and the rod ejection events.

Let's take a look at an example on the next slide.

MEMBER POWERS: Do you think your fuel can tolerate 178 calories per gram?

MR. FINLEY: The question is do we think our fuel can tolerate 178 calories per gram. The answer is yes.

MEMBER POWERS: Do you have experimental data to show that?

MR. FINLEY: Do we have experimental data to show that? Let me ask Westinghouse in the audience, Chris McHugh, with respect to the rod ejection event and the basis for the 200 calorie per gram limit.

MEMBER SIEBER: In this particular case, history is bonk.

MR. HUGLE: This is Dave Hugle. I work for Westinghouse. The question was regarding the calorie per gram and I think most of the committee members are aware of the tests that were conducted in France that showed failure rates at rates much lower than what we're meeting here and the methodology that we used to analyze the rod ejection here for Ginna is based on the 1B approach. Westinghouse has done analysis using a 3-D methodology where we've shown that we can meet failure rates at a much, much lower consistent with the test data that was presented as a result of the test that were done by the French. And as I think the committee that the NRC is currently investigating what would be a new and proper limit to be used for the rod ejection event.

When we did look at the rod ejection event using a 3-D methodology what we found is if you take into consideration the actual rod insertion limits and conditions in the core what we find is we don't even get to a condition where you have DNB. So we are still investigating that, what is an appropriate limit to use going forward and I think the staff again is aware that that is out there. But since this was the older methodology that we're using, we feel that this is an acceptable approach for looking at the rod ejection and again we did present information where we showed with a 3-D analysis.

MEMBER POWERS: I just don't know what to do with this. This is you come in here. I can show you experimental data that shows fuel won't tolerate these kinds of power inputs and on the face of them experimental data says will not tolerate this kind of power input, cannot be an acceptable basis for operating a reactor. You come in and you tell me you did an analysis that's not part of the licensing application, not reviewed and say everything's okay. What am I supposed to do with this?

MR. HUGLE: That's I think because the staff has not come to an agreement as far as what is acceptable.

MEMBER POWERS: Well, the staff, I don't know where to go. If the staff hasn't come to an agreement is another problem I have. I don't know where to go. Here is a clear case that says this power uprate cannot be tolerated because you will violate things. I can show experimental data of the Code the fuel cannot tolerate.

MR. HUGLE: But I think we've also showed Westinghouse --

MEMBER POWERS: You haven't shown that. You've argued that.

MR. HUGLE: -- has presented information to the NRC that we can meet limits that are consistent with the failure rates that were shown based upon the French data and that we can meet lower limits if we were to look at it in a 3-D manner.

MEMBER POWERS: Well, you're going to have to show them to me because this is clearly a conundrum.

MR. FINLEY: Just to clarify, Dave, correct me if I'm wrong, we have done a 1-D analysis that demonstrates this result here meets the acceptance criteria.

MR. HUGLE: That's correct and we also have presented data that shows if you use a 3-D approach and we even presented what we believe are acceptable limits to use going forward for the rod ejection event, but as I understand that I don't think that there has been agreement as to what is an appropriate limit moving forward. So this analysis methodology as Mark has stated is based upon a 1-D approach and we believe --

MEMBER POWERS: I don't care what -- Either it's an inadequate analysis or it is a clear case that we can't approve this power uprate.

MR. HUGLE: We believe that it is an adequate analysis based upon our clear understanding of what happens in a rod ejection event. Again, if you were to analyze the rod ejection event, full power conditions based upon --

MEMBER POWERS: We're getting nowhere here. I understand what you're saying. That's not the argument that's presented here.

CHAIRMAN WALLIS: Can we get somewhere please? I think that you're claiming that there is a criterion of 200 calories per gram.

MR. HUGLE: That's correct based on the current methodology.

CHAIRMAN WALLIS: Presumably approved by the NRC.

MR. FINLEY: That's correct.

MR. HUGLE: That's correct.

CHAIRMAN WALLIS: And you have shown that you come up with a smaller number.

MR. FINLEY: Yes.

CHAIRMAN WALLIS: Now there may be experimental evidence which puts this criterion in question.

MR. FINLEY: That's correct.

CHAIRMAN WALLIS: But there still is the existing criterion. Is that right?

MR. HUGLE: That's right.

MEMBER POWERS: But my job, Graham, is to say whether this is safe or not and it clearly diverges from available experimental data. I don't care what the criterion is. It diverges from the available -- The fact of the matter is, the pure and simple fact of the matter is, that fuel will not tolerate this kind of power input.

MR. HUGLE: Also stated, analysis based upon actual conditions will show you won't even get into DNB and that's with conservative assumptions.

MEMBER POWERS: Then you should have presented that analysis here.

MEMBER DENNING: I do have another question.

MR. HUGLE: We have not taken that approach because we have not gotten agreement from the staff as far as what is an appropriate limit to meet and that's part of the problem.

MEMBER DENNING: With regard to the current condition, the current operating condition, what is the result of analyses for the current and what's the criterion for the current?

MR. FINLEY: The criterion is the same, the 200 calories per gram.

MR. HUGLE: The same. The criterion has not changed.

MEMBER DENNING: What's the result?

MR. FINLEY: But the result, I'm not aware of the result offhand. I don't know if Chris McHugh from Westinghouse or Dave. We can certainly get you that result.

MEMBER POWERS: What difference would it make? Then you can't tell me the physical reality has changed because of the previous analysis.

MEMBER DENNING: No, Dana, I think difference is a matter of -- I don't think there's any question.

MEMBER POWERS: Absolutely.

MEMBER DENNING: There is an issue on rod ejection and whether the existing criteria that people have been using is really satisfactory. For EPU, there is a question of does it make any difference the fact that they're at higher power as to what the result is. I suspect that the increased power makes it a worse result.

MEMBER POWERS: Whether it does or not doesn't change the fact that we cannot go around approving things that are in defiance of physical fact. I mean that's silly to do that.

MEMBER DENNING: I understand your point.

MEMBER BONACA: Well, this at least raises the question of why did you use 1B model when you know that if you use a 3D neutronic model most likely you'll get a much lower --

MR. HUGLE: Again, we don't even predict

DNB for the rod ejection event.

MEMBER BONACA: I understand that.

MR. HUGLE: And failure is not an issue. But again, we've gotten the methodology approved and we have done the calculations for several plants where, as I understand it and I'm not an expert in rod ejection, I apologize, but there is some question moving forward is what an appropriate limit to use for the failure of the fuel. If 200 is too high, what is appropriate? I know that we have done conservative 3-D analysis and shown that, I think, were in the range of 50 calories per gram in terms of the limit.

MEMBER BONACA: Incredible.

MR. HUGLE: I know that they're well under in using a 3-D approach, but again, since that has not been resolved, we still rely on this conservative 1-D methodology that we have used for all the Westinghouse fleet for doing reloads and for doing uprates and for doing all kinds of analysis and continue to meet the existing limit and that's what we've done here for the uprating analysis.

MEMBER DENNING: What I think we should do right now is clearly we have to come back to this with staff. Let's not do that right now because I don't want to bounce them up and down. Let's go through this and when the staff makes their presentation, we'll definitely hit this item again and we may need more input from you. But I think -- We've heard the input. Now the question is what do we do with it and part of that is what the staff has agreed. Dana, we'll come back to this hard when we talk to the staff.

MR. HUGLE: But it is definitely an issue out there.

MEMBER DENNING: Okay.

MEMBER BONACA: Before you go forward, on the previous slide, I had a question on 19. Now for example for the overheating, you get the results of 2747 psi which is like three psi below the limit. Oh, 2500, it's 2750. Doesn't this number depend on your high pressure trip set point and why didn't you adjust it down to prevent to be so close to limits?

MR. FINLEY: As I said earlier, we did adjust pressurizer safety valve set points and other inputs to achieve acceptable results here. We did not attempt to demonstrate additional margin to the acceptance criteria. But as I'll demonstrate here on the next slide and the slide after, that was with the knowledge that again these methods are very conservative and our inputs that bound the operation of the plant are also very conservative. So a more realistic result is a quite a bit lower in terms of pressure.

MEMBER BONACA: What was the volume before you had the uprate?

MR. FINLEY: For the loss of load?

MEMBER BONACA: Yes.

MR. FINLEY: 2737.

MEMBER BONACA: So you open the safeties even in that case.

MR. FINLEY: That's correct. That's correct and that's a good point because it's really the safety valve set point that determines what the peak pressure is for this event. You do have some overshoot above the set point, but that's not very sensitive to the power level.

MEMBER BONACA: Okay. So mechanically you cycle the safties before too.

MR. FINLEY: That's correct.

MEMBER BONACA: So you do the same.

MEMBER DENNING: But there is another point here that goes beyond this particular one in which you didn't do and that is one of the things that really struck the subcommittee was how much the criteria had changed because particularly if you look at the DNB, I don't remember exactly what it was, like 1.62 or something like that, was the criterion previously. So clearly there's a significant change in margin. Then the question is is the residual margin still acceptable.

CHAIRMAN WALLIS: I think we should explain to the full committee that this criterion for DNBR is not set by the agency. It's set by the licensee and we went through this with the subcommittee.

MEMBER BONACA: There is a minimum that you cannot exceed.

CHAIRMAN WALLIS: There is a minimum which is less than that which is really the --

MR. FINLEY: Let me ask to go to the next slide because I think that will lead us through this discussion with respect to DNBR and these are the results and the criteria that apply to the loss of flow analysis in particular. That was one of the limiting non-LOCA events you saw in the previous slide. If you start at the top and essentially by definition, critical heat flux is the 1.0 for DNBR and of course, we bound that by looking, by doing extensive testing and bounding that test data with a more restrictive 1.17 criteria.

Then we establish a design limit of 1.24. The purpose there is bound the variation in parameters such as temperature, pressure, flow and geometry information. Then beyond that, we establish the safety analysis limit and this is done as Dr. Wallis mentioned by Westinghouse as part of the methodology in the fuel design, but it's reviewed and approved by NRC as well and for Ginna, we consider this an NRC approved limit that if we were to exceed or go below this with respect to DNBR, we would come back to the NRC to gain approval of that analysis.

So whereas it is set by Westinghouse based on experience, it is approved by NRC and we consider the safety limit, if you will, for this event. That's 1.38 and that --

MEMBER DENNING: Safety analysis limit, I think we have to be very careful about safety limits.

MR. FINLEY: That's correct. Safety analysis limit. Thank you. Safety analysis limit.

CHAIRMAN WALLIS: That's for Ginna because other plants have other numbers.

MR. FINLEY: And this applies to Ginna. That's correct and this provides additional margin to the 1.24 design limit and that's to provide us some margin for cycle-to-cycle changes in parameters that would affect DNBR. So that's a stack up of the uncertainties in the margins that we have just in the safety analysis limit itself.

Then below that just to give you an example for how conservative the non-LOCA analysis itself is, you see the result there 1.385, just above the safety analysis limit. That uses a very conservative time delay for the --

CHAIRMAN WALLIS: Please. You keep using "very" to qualify "conservative." I think you ought to just say conservative because what's "very conservative" is somewhat subjective.

MR. FINLEY: Understand. I agree. Uses a conservative time delay of 1.4 seconds.

MEMBER BONACA: You have to use conservative. You do have extreme value there and so you could use that.

MR. FINLEY: That's correct and this gets back to the approach that we used. We had a conservative time delay in our previous analysis prior to EPU and we had significant margin there more so than for the EPU analysis. When we did the EPU analysis, we did not change that input just like we didn't change many other inputs because we had acceptable results.

The time delay that was used in the analysis was 1.4 seconds timing to reach the low flow condition before you would get a reactor trip. Based on one-time test data, we're comfortable that 1.0 seconds is an actual, still bounding, but conservative time delay for this event.

MEMBER BONACA: I understand.

MR. FINLEY: And if we were to use 1.0 seconds versus 1.4, you see the improvement here, a slight improvement in the result. In addition to that, the methodology used for this analysis did not credit the fact that pressure will increase during the transient and in fact, at the time of minimum DNBR, the pressure has increased approximately 75 psi. Of course, that's beneficial in DNBR space.

MEMBER BONACA: I guess the way I was going with my questioning was I understand you have margin. Typically, you stay away from the limits because if you have any real changes taking place in the plant, you have to evaluate those values since you are so close to the margin. I was trying to understand the logic.

MR. FINLEY: Actually, that's a very good point and let me elaborate. Your point actually helps to justify the approach that we used. In other words, we maximized the operating envelope that we have such that when we do make changes cycle to cycle that we don't have to revise the UFSAR analysis and go back to the NRC staff to gain approval. So one of the reasons for maximizing our operating windows is to avoid having to revise the limiting analysis cycle to cycle.

MEMBER BONACA: So you apply that margin really to parameters that affect the results. Okay.

MR. FINLEY: That's exactly right.

MEMBER BONACA: All right.

MR. FINLEY: We apply the margin to operating parameters that we now control.

MEMBER BONACA: Okay. Thank you.

MR. FINLEY: Other questions on DNB? Next slide. With respect to pressure, similar argument or stack-up if you will of the design limit in this case and the more realistic results below. Ginna's been analyzed through the anticipated transient without SCRAM event to be able to withstand a pressure as high as 3200 psig with no deformation to the plant pressure retaining components. Above 3200 psig there is some potential for deformation, not likely a catastrophic failure, but for example, perhaps elongation of bolting on the reactor vessel head phalange where you might get leakage as opposed to failure.

We've done a hydrostatic pressure test under cold conditions to 3100 psig. The design limit is 110 percent of design pressure. Design pressure being 2500 psia results in design limit of 2748.5 psia.

The safety analysis result for the loss of load event which I believe we talked about previous was close, 2747. We do open the pressurizer safety valves, but they are successful in maintaining the pressure below the --

CHAIRMAN WALLIS: This is really set by the set point on the valves, the relief valves.

MR. FINLEY: That's correct. There is a small effect on the overshoot after the safety is open but predominantly this peak pressure is set by the safety valve set point.

But if you, for example, look at a more realistic transient in the plant and we talked about control systems, control grade control systems, previously, both the steam dump system and the pressurizer spray system would typically operate in this transient. These are very reliable systems. We maintain them to be reliable. Taking credit for those would result in a better-than-100-pound improvement in the peak pressure.

CHAIRMAN WALLIS: I guess I would say that at subcommittee we said it's all very well you can say this, but we don't know what's the probability of these things and if you did a PRA type thing, you would say we know that the steam dump and the pressurizer spray are going to work with the reliability of 99 percent or something and you go through this and say the probability of ever getting close to the limit is minute.

MR. FINLEY: Yes.

CHAIRMAN WALLIS: You actually have some numbers.

MR. FINLEY: Yes, and actually --

CHAIRMAN WALLIS: But here you're just talking qualitatively.

MR. FINLEY: To illustrate that point, again look at the bottom bullet there. The Ginna design is to have a reactor trip essentially immediately following a turbine trip. By design, the turbine trip will electrically cause a reactor trip. This is a very reliable configuration. Either one of two relays being energized as a result of the turbine trip would then cause a reactor trip and I've talked with our PRA folks about this and we believe the probability of success with respect to the reactor trip on turbine trip is between 99.9 and 99.99 percent. Extremely reliable.

MEMBER SIEBER: Wasn't there within the last month a failure in an operating plant of reactor trip on turbine trip? It seems to me I read that in -

MR. FINLEY: I'm not aware of one.

MEMBER SIEBER: I'll look it up.

MR. FINLEY: But that's very important to this event because what drives this event is the power mismatch, essentially the delay between the turbine trip where you stop your heat removal and the reactor trip later. But the plant is designed to have essentially simultaneous trips and again it's very reliable. If you were to take credit for that reactor trip on the turbine trip, then it really becomes a very benign transient altogether and in fact, this is demonstrated by actual plant data. We don't, for example, even lift the PORVs in addition to not lifting the safeties.

MEMBER BONACA: That was an objective that came after TMI anyway that you would stay below the PORV so you wouldn't actuate them. That's -- Okay.

MR. FINLEY: That's correct.

MEMBER BONACA: You went a long way, but

we go to the bottom line. That's good.

MR. FINLEY: Yes.

MEMBER SIEBER: Let me ask another question since you seem to want to discuss this. Is the actual turbine trip device and the circuitry that connects the turbine trip to the reactor trip, is that all safety grade?

MR. FINLEY: No and that's --

MEMBER SIEBER: Then you can't take credit for it.

MR. FINLEY: And that's in fact why we don't in the safety analysis, why we don't --

MEMBER SIEBER: So it doesn't meet the general design criteria.

MR. FINLEY: That's correct.

MEMBER SIEBER: Okay.

MR. FINLEY: And that's the reason why we don't analytically in the approved safety analysis take credit for that.

MEMBER SIEBER: Yes, and that's the way the rules read and you're doing what the rules say. It's not worth too much of a discussion to say if we actually took credit for something that you can't take credit for, it would be even better.

MR. FINLEY: But I think it is important

in terms of how the plant will really operate and with respect to margin, these trips will be here.

MEMBER SIEBER: Yes, but it doesn't have the pedigree.

MR. FINLEY: I understand.

MEMBER SIEBER: Why don't we just move on?

MEMBER BONACA: One other thing that's important to know is that if it already works, whatever the problem may be, they have a target there that is below the PORVs.

MR. FINLEY: Yes.

MEMBER BONACA: And so this kind of a transient will not cause most likely the PORVs to be actuated and that's a significant issue.

MR. FINLEY: Right.

MEMBER SIEBER: That's a good thing because most of the failures are failures to close as opposed to failures to open.

MR. FINLEY: Right.

MEMBER BONACA: That's why it's really there to prevent in fact those things from happening.

MR. FINLEY: That's correct. Yes.

MEMBER DENNING: Continue.

MR. FINLEY: Just to sum up with respect to non-LOCA, all of the non-LOCA results meet acceptance criteria and there is margin in both the methods and in the inputs as well as margin and conservatism in the limits themselves.

I'll real briefly touch on the results for loss of coolant accident analysis for the Ginna EPU. The large break result was 1870 as compared again to the criterion you know of 2200.

MEMBER SIEBER: 2200.

CHAIRMAN WALLIS: There are three criteria. You don't show the other ones.

MR. FINLEY: I don't have the other criteria. We are well within the other, all five criteria actually for 10 CFR 50.46.

CHAIRMAN WALLIS: You're well below the other criteria.

MR. FINLEY: Yes.

CHAIRMAN WALLIS: I don't remember.

MEMBER SIEBER: Oxidation was very small.

MR. FINLEY: Yes.

CHAIRMAN WALLIS: Well below. Okay.

MEMBER POWERS: But that depends on how they use the fuel. Right?

MEMBER SIEBER: It's like one percent versus 17. It's zero so they come in very low.

MR. FINLEY: Right. We did look at both

the transient oxidation and the oxidation pre-transient and the combination is below, for the LOCA oxidation limit, below 17 percent.

MEMBER SIEBER: With a lot of margin.

MR. FINLEY: With a lot of margin, yes. Now we did, as I said before, revise the BE-LOCA methodology here for the large break analysis. That was a necessary thing to do for us in order for us to demonstrate acceptable results for the large break analysis, but that large break --

MEMBER SIEBER: That's why you got such a low number.

MR. FINLEY: That's correct. That BE ASTRUM type analysis that Westinghouse has approved provided the margin that we needed to demonstrate acceptable results for the EPU.

With respect to small break as I mentioned, we haven't changed the method there. It's the NOTRUMP method, but you can see by the much lower peak clad temperature that we are a large break limited plant and not a small break limited plant, 1167 for the peak clad temperature and again all of the criteria associated with the 10 CFR 50.46 were met with a good deal of margin.

MEMBER SIEBER: Now you're using the old

decay heat curve.

MR. FINLEY: With respect to the best estimate, that does not use the Appendix K decay heat curve. It uses a more realistic decay heat curve.

MEMBER SIEBER: So the 20 percent margin that was built into the old Appendix K is not here.

MR. FINLEY: That's correct. That's not in the best estimate methodology.

MEMBER SIEBER: Okay.

MR. FINLEY: Okay?

CHAIRMAN WALLIS: It is there in your probabilistic assessment, isn't it? You're bringing up realistic assessment of the uncertainties in this decay heat.

MR. FINLEY: That's a good point. Yes, certainly -

CHAIRMAN WALLIS: -- the margin completely.

MR. FINLEY: Certainly. Decay heat uncertainty is one of the many uncertainties in the best estimate methodology that's accounted for. Yes.

MEMBER SIEBER: But there was a tremendous margin pad on the old Appendix K which later even though you account for uncertainty, the margin is much smaller.

MR. FINLEY: Yes.

MEMBER SIEBER: Justifiably so in my opinion.

MR. FINLEY: Okay, and the last --

MEMBER BONACA: I have a question on this just because I couldn't find the information in the material. If you have a large break LOCA and you have everything works, no single failures. How long does the operator have to switch to recirculation? I mean that depends on how large is your RWST, but I couldn't find the information. I don't think it's that large, is it?

MR. FINLEY: If everything works and we have absolute maximum flow rates with all the pumps, higher than what is really realistic, 24 minutes is the time to establish recirculation. In other words, the refueling water storage tank would then be pumped down to the point that we had to establish recirculation.

MEMBER BONACA: How large is this RWST?

MR. FINLEY: How large is the RWST?

MEMBER BONACA: One thousand. 330, okay.

MEMBER SIEBER: How big was that?

MR. GILLOW: I'm Ron Gillow, Shift Manager. Three hundred thirty thousand gallons is the

-- We keep about 315,000 in the RWST at any one time.

MEMBER BONACA: All right. Thank you.

MR. FINLEY: With respect to the long-term cooling analysis, again there was a significant amount of work and several questions from the staff and good questions from the staff that were responded to with new analysis in the long term cooling area. So we had some discussion about that in the subcommittee meeting and I'd like to spend a little time with that.

MEMBER DENNING: I don't think you have to spend a lot of time on this frankly.

MR. FINLEY: I understand. Thank you. First, with respect to the Ginna design, we have high head safety injection pumps aligned to the cold legs that would automatically inject when RCS pressure initiates the safety injection system and pressure decreases below about 1400 psi. That's the shutoff approximately for these pumps.

We also have low head safety injection. We call it residual heat removal pumps or RHR pumps and those are lower pressure obviously. Shut off pressure around 140 psi. But Ginna is a two-loop Westinghouse design and unique to that design is what we call upper plenum injection. Those low head safety injection pumps are aligned directly to the upper plenum via nozzles in the reactor vessel itself and inject just above the core in the upper plenum. This is a very robust design with respect to this concern for long term cooling.

MEMBER SIEBER: You should also point out that you have big accumulators that operate at pretty high pressure.

MR. FINLEY: That's correct. We also have large accumulators that are pressurized to about 700 psi which is a relatively high pressure which benefit in loss of coolant as well.

The point I want to make on this slide is that we essentially -- When pressure lowers below the shutoff of the low head SI pumps, we automatically have simultaneous injection to both the hot side and the cold side through these two sets of pumps and for a large break LOCA, obviously that's what happens. RCS pressure decreases rapidly below the shutoff of both the high head and the low head pumps. So we get simultaneous injection both to the cold side and to the hot side and no matter which side of the reactor coolant system the break is on, we get flushing flow through the core to prevent increase of the concentration.

Now I will say and the question came up

previously --

MEMBER BONACA: You don't have to switch to hot leg.

MR. FINLEY: Actually, let me speak. I will say though that's for the injection phase of the event. Okay. When the RWST as was pointed out before is pumped down, we do need to switch to the recirculation phase. Now when we switch to the recirculation phase, by procedure we turn off the high head safety injection pumps and the basis for that is that Ginna was not designed for simultaneous injection in the recirculation phase and initially in the recirculation phase the sump temperature as high as it is would challenge the NPSH margin on those high head safety injection pumps. So procedurally we actually turn those pumps off in the recirculation phase and we recirculate with the low head pumps initially.

We do do an analysis, a very conservative, I used that word "very" again, Dr., a conservative analysis to --

MEMBER SIEBER: Very, very.

MR. FINLEY: A conservative analysis assuming that when we turn those high head safety injection pumps off that we now begin to get concentration in the core region and, of course, in that case it would have to be a hot side break that would then carry all of the upper plenum injection flow out the break without any significant mixing in the core region. That's we feel a very conservative assumption.

CHAIRMAN WALLIS: "Very" again.

MR. FINLEY: I do think "very" applies in that. So --

VICE CHAIRMAN SHACK: It's not one word.

MEMBER SIEBER: Hyphenated.

MR. FINLEY: So we do calculate and this is where in response to staff questions with regard to what precisely is the mixing volume in that core region and what is the void fraction in the coolant in that core region. The staff asked those questions and previously using the simplified method that Westinghouse provided, those issues weren't addressed as rigorously as we are now and we actually did an analysis using the Westinghouse Cobra Track Code to calculate the void fraction and the mixing of the two-phased level through the course of this event and input that into the boron concentration analysis.

May I ask you just to click on that slide right there. Go one more. Just to demonstrate the conservative nature of this analysis, you see a dotted line here on this slide which describes the core mixing, the boundary, if you will, of the core mixing volume in this concentration calculation. What we do is we assume that most of that upper plenum injection flow actually gets carried out the break and this break is on the hot side as we've said; where in actual fact, we feel there would be tremendous amount of mixing across that boundary volume to dilute essentially that core region.

Because we have not completely demonstrated that level of mixing and gotten that approval through the staff, we did not take credit for that. All we take credit for is enough of the upper plenum injection flow to essentially replace the mass that's boiled off in the process. But with this assumption, we calculated a time to concentrate during this accident.

MEMBER DENNING: Let me interrupt you because unless the Committee really wants to go into this. I think that if you look at this slide you see that part of this is that essentially all the safety injection in the upper plenum is assumed to go out the break in this analysis.

I think that we have greater concerns about the more traditional non upper head injection plants and what happens there. I think this is -- I frankly it's more artificial here. You've gone through the analyses. People can read them. Since we're going to come back and have with the staff some significant discussions on an earlier issue, what I'd like you to do unless people object I'd like to move.

MEMBER BONACA: I just had one question.

MEMBER DENNING: Go ahead.

MEMBER BONACA: Does it imply that you have a pooling up there of water and then it comes through the side?

MR. FINLEY: Not a pooling, but of course what you have is rigorous boiling in the core and you have entrainment of some of that injected coolant out the break.

MEMBER BONACA: Okay. I don't want to -- It was more for curiosity. You go ahead.

MEMBER DENNING: Okay. If you don't mind then, I think that you should jump to the conclusions of the safety analysis and move on to the rest of the presentation.

MR. FINLEY: All right. Thank you and, yes, just to conclude with respect to safety analysis, all of the safety analysis for the EPU for Ginna were completed and meet the approved acceptance criteria.

Our nuclear steam supply system is robust and our engineered safety features are robust and these results are consistent with the analyses that were done for the Kewaunee plant again that operates at a similar power level to what Ginna is requesting.

Any other questions for me in the safety analysis area? Okay. I would like to introduce Jim Dunne. He's the Project Lead Engineer and he'll discuss some mechanical impacts.

CHAIRMAN WALLIS: Which are not safety related?

MR. FINLEY: I'll let Jim answer that.

MR. DUNNE: Good morning. My name is Jim Dunne. I hold the position of Engineering Consultant to the Constellation organization and I'm at Ginna. I've been in the Engineering Department at Ginna for 15 years and for the past three years, I've been Lead Mechanical Engineer for the uprate project.

Basically what I'm going to go over briefly is to discuss the impact of the EPU on some various mechanical systems and components. Specifically I'll go over the impact on steam generator vibration, balance plant heat exchanger vibration, the vibration monitoring program that we plan on using for the piping due to EPU and also the impact of the EPU on the flow accelerated corrosion program that's in place at Ginna.

With regard to the steam generators, it was previously stated that we replaced our generators in '96 with new generators. The design basis for the new generators included a detailed vibration analysis of the tube bundle for the impact of the operating conditions, specifically looked at vibration potential in the area of the tube bundle that saw cross flow which would be the U-band region and the downcomer entrance into the bottom of the tube bundle.

The parameters that were investigated as part of the design of the replacement generator were fluidelastic instability, vortex shedding in the tube bundle region, random turbulence excitation and tube wear in the U-band region. So basically the original design in the generators had acceptance criteria that we had to satisfy in the design of the new generators for all four of those areas.

With the EPU, we went back to the OEM which in this case is BNW Canada and asked them to revise their vibration analysis for the EPU operating conditions. So they basically repeated their analysis that they did for the original design and looked at the impact of uprate on these four areas and their conclusions where that basically the steam jointed (PH) tube bundle design was adequately supported to prevent any flow induced vibration due to EPU operating conditions.

VICE CHAIRMAN SHACK: Have you have any experience with frettings with the new generator?

MR. DUNNE: We haven't seen any real indications of fretting with the new generators at all.

The second issue that we believe probably the ACRS is interested in based upon the BWR experiences, a potential for vibration damage due to steam separators in our case based upon the BWR steam dryer issues. Basically, we think our design is appreciably different than the BWR dryer design and therefore is not really susceptible to any flow induced vibration problems.

Our steam separators with the new generators, we basically have 85 primary/secondary modules that are basically in parallel. The number of modules is controlled basically by the size of our upper steam shell region. We can stuff has many modules in the upper shell as possible and with our design that came out to be 85.

Both the primary and secondary separators are a centrifugal type separator in comparison to our original design which had three swirl vein primary separators and then a chevron design for the secondary separation. Because of the design, the flow through the separators is basically axial in nature. So there is no minimal cross flow velocity across the separator modules that could cause vibration.

Additionally, the separate design is a rigid design. All the separator modules are interconnected with each other by separator ties that get welded to the adjacent modules so that any one module trying to move is going to transmit its load to the entire separator bundle, if you will. So it's basically a honeycomb structure. As such, we believe it's a very rigid design.

Other things to note is that because we have modules and can put 85 of them, the design for those modules plus primary and secondary which based upon actual full scale testing of the modules for steam and flow at operating pressures that bound where the plants would typically operate. With that, at uprate, we are going to steam flow that is still bounded by the original testing, the full scale testing, that was done on the modules. The modules have been tested for steam flows up to 58,000 pounds per hour steam flow and at uprate, we're going to be going from around 38,000 pounds per hour up to around 45,000 pounds per hour. So we're still well below where the modules were tested.

And we will be the lead B&W unit at uprate for steam flow through an operating unit. However, we are not that far apart from some other B&W replacement generators that have done power uprates. I think our flow is going to be approximately five percent higher than the steam flow that both Bryon and Braidwood have gone to with their uprates. So we don't believe we are basically pushing the window on steam flow through the modules.

To try and visualize the differences between the BWR dryers and the actual Ginna steam generator separator modules, we have this cartoon, if you will, which is this is our understanding of how the BWR steam dryers are set up where you have flow coming out and then a lot of -- flow going over the steam nozzle where they basically had problems at Quad Cities.

The Ginna design, we have all these modules stacked across here. This portion up here is our secondary modules. So we basically have flow coming out of all these 85 modules and then basically approaching the main steam nozzle and controlled by the curvature of the upper head itself. So as such, we have a much simpler flow pattern in our steam generator upper head than you would see in the BWR steam dryer design. And there really are no -

MEMBER POWERS: I'm not sure I disagree with you, but what this actually shows that you've drawn simpler arrows. It doesn't show that you have a simpler flow pattern. I could have drawn a set of arrows on the graph that suggests there is some complexity in your flow. Are the arrows drawn based on anything other --

MR. DUNNE: It's my hand drawing. They're not --

MEMBER POWERS: You could imagine all kinds of complexity in the corners and things like that.

MR. DUNNE: You are going to get some imbalance of flows between separators over in this region versus in the middle. But in general, you're going to have a flow pattern that's going to try and follow the contour of the head of the generator and we think that's a more simple flow pattern than coming out here and having to turn around and approach this.

MEMBER POWERS: The problem I have is that when the folks from Quad Cities came in and made arguments on this, they drew arrows on figures and they said they firmly believe they had no problem. Okay. You can draw figures here and say I firmly I believe I have no problem. It does not mean you're not going to have a problem.

MR. DUNNE: The operating experience to date on the B&W design --

MEMBER POWERS: Power uprate level is a little thin.

CHAIRMAN WALLIS: You don't give numbers on velocities. So your velocities I think are much lower than BWR steam velocities.

MR. DUNNE: The velocities I think through the steam separators themselves are on the order of 40 to 50 feet per second and then I think one of the issues that Quad Cities was that they had high steam velocities in their main steam piping in comparison to the rest of the BWR fleet. Basically, our main steam piping velocities are going to be going from 135 feet per second up to around 160 feet per second and we don't believe those are inordinately high steam velocities for a steam piping system.

MEMBER DENNING: Okay. Proceed.

MR. DUNNE: The next area where we've

looked for uprate the impact of vibration is on the balance of plant heat exchanges, specifically the major heat exchangers in the power conversion cycle which would be the feedwater heaters, the moisture separator reheaters and also the impact on the higher exhaust flows to the condenser on the condenser tubing.

Basically, we have two trains of feedwater heaters and we have five feedwater heaters in each train, four low pressure and one high pressure. We went to basically a feedwater heater manufacturer, asked them to assess our feedwater heater and MSR design at the EPU conditions for both vibration thermal performance and erosion due to increased velocities. The manufacturer we chose was the manufacturer that was directly responsible for the tube bundle design on six of our FIV feedwater heaters that are presenting installed and also responsible for the design of our MSR tube bundles and they also had access to design information for our other four fuel heaters.

So they did their assessment of the EPU conditions. They concluded there were no FIV issues with the EPU. They identify that we would have on a large number of inlet nozzles higher velocities than which we typically design heat exchanges to if you were going to design them to the uprated conditions and they viewed that as being a potential long-term erosion concern and basically recommended that we monitor all those nozzles going forward which is basically what our plan is. So we've added those nozzles into our erosion/corrosion program. We'll get baseline reading for where they are before EPU and then monitor them going forward.

The other areas on the condenser tubing, when we replaced our condensers or retubed our condensers in '95, we replaced Admiralty tubing with stainless steel tubing and at that time we staked our entire tube bundle. Because our tube bundle was staked in '95, evaluation on the tube bundle indicated that the condenser was acceptable. If we had not staked in '95, we would have had to have basically staked the condenser tube bundle for EPU.

The other area on vibration monitoring we have is a vibration monitoring program to assess the impact of the EPU conditions on piping vibration basically in the power conversion piping systems where we are increasing flows and that similar to other plants that have done EPUs, we are basically going to do a pre EPU walkdown at full power to baseline the existing vibration levels in the plant and then after we come up and do our full power condition at post EPU, we will repeat that and assess if there's any adverse increase in vibration at any part of the system.

The vibration program is basically two phased. The first part is to do a visual walkdown of all of the systems which for the pre EPU we have completed. Based upon that visual walkdown, we are identifying select areas within piping systems where we want to go back and actually get actual vibration data with vibration monitoring equipment that we can have a baseline for comparing the post EPU results and that's basically what we plan on doing during our power escalation testing which would be to do the visual walkdowns to identify if there are any new areas that are vibrating at post EPU conditions and also revisit those areas where we got vibration data pre EPU, repeat the data and quantify what the deltas are and assess whether there are conditions that we need to address.

The final area I would like to quickly go over is the impact of EPU on our Flow Accelerated Corrosion Program. Like most of the nuclear industry, we do have a Flow Accelerated Corrosion Program to monitor long term wear of piping systems' components and it's basically a combination of analytical tools developed by EPRI in combination with actual field data to assess predictive wear rates going forward and determine when we need to reinspect and to when we may need to do repairs. So we have gone through and used the analytical tool that EPRI has for assessing vibration levels, compared the calculated vibration levels with the pre EPU flows and thermal dynamic conditions in the various systems and then recalculated them at the EPU flows and thermal dynamic conditions to assess analytically what we expect the change in erosion rates to be.

It varies from system to system. But the numbers we've seen are typically varied from increased erosion rates anywhere from two to three percent up to 20 to 25 percent. We've reviewed that data to see based upon where we are presently in our erosion plan whether there are any components that need to be replaced prior to EPU due to a potential for increased erosion rates. We have not identified any components that need replacement prior to EPU.

We also have added new components to our program. Some of them are the feedwater heater nozzles that I talked about and we also have piping that before was exempt from the erosion/corrosion program or FAC program because of thermal dynamic conditions that now no longer screen out. Specifically the piping between our No. 2 feedwater heater and the No. 3 feedwater heater was below 212 degrees Fahrenheit, so it screened out of the FAC program. At EPU, we're going from slightly below to slightly above. So now it screens in and we're going to add that piping to the program and for all the new components, we're getting baseline readings prior to implementing EPU.

So basically our first outage after the uprate, we plan on going in and doing increased inspections, a piping over what we would normally do basically to get feedback as to what we're seeing in the actual erosion rates to determine whether any of the calculated values to each are adjusted according and then continue to assess the piping systems going forward by periodic monitoring of the programs similar to what we do right now. That's all I have.

MEMBER DENNING: Anything else here? Okay. Let's move to PRA and let's hold the PRA to ten minutes.

MR. DUNNE: I'd like to introduce Rod Cavedo who's from our Corporate PRA Group in

Annapolis.

MEMBER DENNING: I'll sit on George here and see if we can move quickly through this.

MR. CAVEDO: My name is Rob Cavedo and I'm here to present the -- I've been working in the PRA field for 17 years. I'm here to present the results of the PRA and insights. I'm here to talk about the -- That's okay.

The PRA we've had a lot of discussion on margins here and the PRA is our tool to quantify what the actual impact to the margin is. We look at everything that can be affected. We look at the changes to the initiating event frequency. We look at success criteria changes. We look at equipment failure rate changes. And we look at the operator response time changes which that is what drove the change in risk associated with the power uprate, the reduction amount of operator response time. We also identified risk beneficial plant changes. We calculated this using internal, external and shutdown events.

For the initiating event frequency, we had not new PSA initiators. So that doesn't mean that there weren't any changes in the initiating event frequency. That just means that the PRA already evaluates such a large range of initiators that there were no new categories that needed to be developed. But we did adjust based on the engineering evaluations numerous initiating event frequencies. As Jim mentioned, based on flows beyond recommendations, we increased the initiating event frequencies for those areas.

MEMBER SIEBER: What criteria did you use to make those adjustments?

MR. CAVEDO: It was purely based on the engineering reports. So as Jim gave a great example for the heat exchanger, if you were designing a new plant and you would allow a flow of X if the flow actually went beyond that in EPU conditions, we increase the failure rate for the initiating event frequency.

MEMBER SIEBER: By how much and what's the basis for the increase?

MR. CAVEDO: As we discussed in the subcommittee meeting, that's a good question. There is no concrete tool to determine exactly how the initiating event frequency is going to increase as a result of the EPU conditions. So what we did is we took a best estimate as what the change in the initiating event frequency would be and then we did sensitivity evaluations to say let's say the frequency doubles or let's say it's half as much as we thought and we looked at what that range of impacts were and assessed whether it was still acceptable based on those sensitivity studies.

MEMBER SIEBER: Sounds like a lot of engineering judgment.

MR. CAVEDO: It is. Yes, PRA has a lot of engineering judgment in it.

MEMBER SIEBER: Yes.

MR. CAVEDO: Until you have empirical evidence for what's going on, you can't say with certainty what's going to happen in the future.

MEMBER SIEBER: Well, the fact is that PRA doesn't model effects like how much margin you have and what that means as far as failures.

MR. CAVEDO: It does measure that. That's the whole premise of what the -

MEMBER SIEBER: It's built into the frequencies.

MR. CAVEDO: Right, it's built into the frequencies. So you look at what the flow rate is initially and if it's going to go up and if it's going to go beyond these recommended limits from a design perspective, then the failure rate has a chance of increasing. We plan on putting programs in place to try to mitigate that as much as possible, but there is no guarantee. So we increase the failure rate initially and maybe 20 years from now, the failure rate will go back to what it was because we'll find out that our program has totally compensated for any changes to the plant.

The other main area that we evaluated is success criteria changes and we used the Thermal Hydraulic Code to evaluate all of our success criteria changes and we did have to adjust the bleed and feed timing had to be adjusted and the number of PORVs depended on the timing also was affected by the EPU. So that was one of the significant thermal hydraulic changes.

MEMBER SIEBER: But your success criteria are still go/no go criteria.

MR. CAVEDO: The success criteria, it's a very similar approach to how we do all these design type calculations. You keep on adjusting the timing of recovery until it becomes a go or no go. So you say, okay, if you have two PORVs available, then you might have 30 minutes to initiate bleed and feed. But if you have one PORV, then you keep on doing the thermal hydraulic calculation until you have just one

PORV and maybe for one PORV you might have to get it done in 15 minutes.

So it's by the nature of the calculation just like the design calculations. You keep on adjusting the time until you get either success or failure as defined by some criteria. So it's a very similar approach.

We did the comprehensive reviews of the equipment and that was based on the design calculations. The systems operate within allowable limits and post trip because these were only mild degradations, we didn't think the equipment failure rates post trip would be changed significantly.

But the main change as I mentioned before was in the operator response time and, of course, because these's higher decay heat and you have the same inventory and the RCS in the steam generators, then you're going to have reduced amount of time for the operator to respond.

MEMBER APOSTOLAKIS: Do you have any examples of the difference there?

MR. CAVEDO: Yes, I actually think it might have been taken out for this presentation. But for the subcommittee, we gave a full chart and in the submittal, it has all the different timing changes and

I have a chart here. It's Table 2-13 and it shows you what the time is before EPU and the time is after. So if you have a specific human action in mind --

MEMBER APOSTOLAKIS: What's the largest change?

MR. CAVEDO: I don't remember for percentage what the largest change was, but we also had a sensitivity change. You would think that it would be something like 17 percent. Right? That's the power change.

MEMBER APOSTOLAKIS: Not percent. In actual minutes.

MEMBER DENNING: He means minutes.

MEMBER APOSTOLAKIS: What's the allowable change?

MR. CAVEDO: That's what I'm saying. You would think that it would be along those lines, but because there is some base amount of time for the operator to respond to take the actions, then you're looking at the Δtime for a diagnosis. Since there's that base time X and you have some Δtime Y, the percentage can actually be greater than the power uprate change. But there is a chart in here that has the percentages for those changes. Last time, he helped me out. Isn't that the chart? I don't remember what page it's on, but is this it?

MEMBER APOSTOLAKIS: (Inaudible.) I don't see a chart.

MR. HARRISON: Yes, this is Donnie Harrison of the staff. I think the chart you're looking for is on page 22 through 25 of the licensee's submittal. It's Table 213-13. It gives the base times and the EPU times. But I think just to make a simple example would be the one that you up before talking about going from having to reestablish cold leg injection shifted from originally they had 19 hours and it shifted all the way down to about six and a half hours. So it was a huge reduction in time. However, you still have six and a half hours.

MEMBER APOSTOLAKIS: When you have six hours.

MR. HARRISON: And that was the observation.

MEMBER APOSTOLAKIS: Is there anything that is closer?

MR. CAVEDO: The nice summary chart that has all the decay heats in terms of percentages, Table 2.13-12 and you can see stuff like if you're talking about operator fails to manually start a motor driven pump with no auto start signal, the EPU time available is 65 minutes and it was 84 minutes. And there's a summary for all the broad categories of changes. So it has bleed and feed timing that changed and it has the bleed and feed timing. That's was one of the largest changes that we had. It went from 32 minutes available pre EPU to 15 minutes available post EPU.

MEMBER APOSTOLAKIS: So the probability that is calculated.

MR. CAVEDO: Based on the reduction and diagnosis time.

MEMBER APOSTOLAKIS: What model are you using for that?

MR. CAVEDO: We're using the EPRI Human Action Calculator.

MEMBER APOSTOLAKIS: A calculator is not a model. It has four models. A calculator is a just a computer program. So which one of the four are you using?

MR. CAVEDO: For the specific human action, I'm not sure. It automatically selects what is done based on the type of action that you select.

MEMBER DENNING: There is no question what the focus of what's important in this risk assessment. Why don't you go ahead now. Let's see the results on that as far as changes are concerned, but all those changes come from there are changes in the human reliability.

MEMBER APOSTOLAKIS: If you go down to 15 minutes from what, thirty something.

MEMBER DENNING: Yes.

MR. CAVEDO: Yes, all the human actions went down significantly enough that we didn't credit them anymore.

MEMBER BONACA: And bleed and feed is a very important contributor.

MR. CAVEDO: Yes, that reduction in human action time was the largest contribution to the change in risk.

MEMBER DENNING: That's you're about to see. If you go to that table, let's just see the changes.

MEMBER BONACA: Are those PORVs qualified to bleed and feed?

MR. CAVEDO: Could you say that again?

MEMBER BONACA: Are those PORVs qualified to bleed and feed?

MR. CAVEDO: Qualified from a design perspective you mean?

MEMBER BONACA: Yes. Sure.

MR. CAVEDO: No, that's not a design

possibility. The PRA, just to take a step back, credits anything that in reality would work at the plant. So like for Mark's example where you're talking about the loss of load, all of the secondary equipment is credited in the PRA. It's just assigned to failure likelihood based on normally historical evidence.

MEMBER BONACA: Has anybody gone to the vendor and asked the question "Can you pass water through these valves for an extended period of time?"

MR. DUNNE: This is Jim Dunne from Ginna. Basically, the Ginna PORVs were part of the EPRI post EMI testing where they did water discharge and steam discharge and transition from steam to water discharge testing and basically for the PORVs specifically, our PORVs are basically capable of passing low level water discharge. We also use them for our LTOP over pressure protection which is a water discharge scenario.

MEMBER DENNING: Yes. Let's go to the results -

MR. CAVEDO: To the results. So for the results, you can see what the change -- First, let me give a summary for our approach as a site for this. As Mark mentioned and going back to Slide 11, we looked at everything from a system's standpoint and a number of pieces of equipment available. We ensured that that margin remained the same. So that of course factors into the risk results.

But our management asked us to go beyond that and beyond just preserving the systematic success criteria. They wanted us to look for risk beneficial modifications to help to offset the risk associated with the power uprate. So we took a look at that and if you look at where it says "Base Pre EPU" so the first --

MEMBER DENNING: As you do this, you're going to have to still talk in the mike.

MR. CAVEDO: Okay. So as you look at the first row that's here, you can see what the baseline core damage was pre EPU and you can see what the change is post EPU and you can see what the change to LERF (PH) is. But what we did is that we said let's say that we do additional modifications to help to offset this risk and we looked at several of them.

One is making sure that all of the safety injection piping equipment during a fire could be used to mitigate that from an Appendix R type scenario. We looked at the shutdown AOVs to make sure that on loss of air or power that the failure of those won't go to a point where it will cause cavitation of the RHR equipment. We're actually adding accumulators for the charging -- Normally, the charging pumps will go at 60 gallons per minute, but when they lose air they go down to a low speed and that's not as good for bleed and feed and those type of actions. So we're going to get longer amount of time where the charging will run at the higher flow rate and that's very beneficial for the bleed and feed because obviously that's a time critical action. So that gives you extra margin and then this is just a combination of the three scenarios. So you can see that by implementing all of these plant changes we actually end up with a lower core damage post EPU than we did pre EPU without the modifications.

MEMBER BONACA: Now this is a total CDF, right, including external events?

MR. CAVEDO: Yes. This is including everything.

MEMBER BONACA: For your internal event CDF, how much was it originally?

MR. CAVEDO: I don't remember off the top of my head what the --

PARTICIPANT: 1.51. 1.3 pre uprate.

MEMBER BONACA: How good is your PRA?

Just a question I have. How good is this PRA? I know it was originally an IPE and IPEEE.

MR. CAVEDO: Yes, it's been updated several times since the IPE.

MEMBER BONACA: Updating means to verify that all the initiators --

MR. CAVEDO: I guess I should say it's been revised because we have changed human action methodologies and we've done multiple changes to the PRA to increase the fidelity.

MEMBER APOSTOLAKIS: So which one is it?

MR. CAVEDO: For this specific --

MEMBER APOSTOLAKIS: What is the core damage frequency now?

MR. CAVEDO: If we would implement all these, then it would go down.

MEMBER DENNING: It's going to be that bottom one.

MEMBER APOSTOLAKIS: 585?

MEMBER DENNING: Yes.

MR. CAVEDO: We'll implement all the changes.

MEMBER BONACA: So you are reducing it even from the pre?

MEMBER DENNING: Yes. Correct. By these

non EPU --

MEMBER APOSTOLAKIS: (Inaudible.) 585.

MEMBER DENNING: Right. It's essentially the same.

MEMBER BONACA: You say if we implement. Are you implementing or are you not implementing?

MR. CAVEDO: Yes, management is planning on implementing these modifications.

MEMBER BONACA: So that's a commitment they made to the NRC.

MR. FINLEY: This is Mark Finley again, Project Director for the uprate. Yes, these are commitments as a part of our license amendment.

MEMBER BONACA: Thank you.

MEMBER DENNING: Okay. Now this is not a risk-informed modification and I would question some of the things you said about the ability of a PRA to even evaluate the impacts of margins. But nevertheless, we're going to accept where you are right now and I don't think you need to use your conclusion statement. We can read that if we may because what we'd like to do right now if there is no objection is I think we'd like to have the staff come up. Thank you very much and we'll let Mr. Holm complete his final words at the end if that's okay.

Just leave it there. I'm not sure whose it is. I don't think it's ours. And, Pat, we're going to let you get through a few introductory slides, but let's get right into the issue as quickly after that as we can that Dana has raised. Okay?

(Discussion off microphone.)

MR. MILANO: Okay. Getting right into it, the predominant area for the EPU review was the reactor systems analysis and I'm going to be touching on some of the other areas later on. Again, these are from the review Standard RS001 for Reactor Systems Review. These are the predominant areas we look at, fuel and nuclear systems designs, ECS and associated systems, the non-LOCA transients, LOCA transients and ATWS.

Again, from the review standard, the NRC confirms basically as Constellation had indicated in their review. They used NRC approved codes and methods and the staff evaluated those in terms of the plant specific application. We looked at compliance with any limitations and conditions on the use of those codes. We verified a number of input assumptions such as steam generator plugging, what the 10 percent plugging limit and the licensee's evaluation of any vendor service advisories like Ncells in the case of Ginna with Westinghouse that there were appropriate analytical assumptions made and inputted into the analyses and whether the results met applicable requirements and then we looked at whether the processes to ensure that these analyses bound the as-operated conditions that the plant will be operated at and then again, we looked at foreign precipitation in particular in long-term cooling.

Skip through the designs since you've already heard it. They're going to 14 X 14 422 Vantage Plus and these things. We've already talked about the VIPRE versus THINC, that there will be a transition core and the use of transition core penalties and then the use of the revise in the standard thermal design procedures and we talked about the design, the DNBR limits.

Getting right into the non LOCA transients wherein you're going to have your major questions, again the staff followed in particular the guidelines in the Review standard. Most of these events, the non LOCA events, were analyzed by the licensee using RETRAN and VIPRE, both of which again were NRC approved codes. We've already looked at the important assumptions that went into the analysis and evaluations that took place. When I say analysis and evaluations, over about three-quarters of the transient analysis were reanalyzed by Constellation and its vendor. Some were just evaluated.

And the staff found that the results satisfied the applicable requirements and the design limits and you mentioned that before. In the case of Ginna, those safety limits are actually in Tech Spec Section 2.1.

MEMBER DENNING: Okay. Right now then, let's get into the question. Two hundred calories per gram has been accepted in the past. There's evidence of that. Now we're dealing with a power uprate. What's the regulatory position on how we handle that?

MR. MILANO: With that, I'm going to turn it over to Mr. Paul Clifford from the Fuels and Nuclear Performance branch who is going to answer those questions. Paul.

MR. CLIFFORD: Is there a host of questions that need to be answered?

MEMBER DENNING: No, there is just one question and that is how do you justify accepting 200 calories per gram or something that's approximating that as far as the analysis that we have here when there is experimental evidence that would indicate that we should be reconsidering that 200 calories per gram.

MR. CLIFFORD: Okay. It's important first to note that there's three criteria and they all have different limits for the rod ejection case. The first is RCS peak pressure and I don't think there's any dispute about that. The second is a coolable geometry which goes back to GDC 28 and the third is offsite dose or control room dose.

Let's start with the coolable geometry GDC 28. That was set at 280 calories per gram in Reg Guide 1.77. For many years, the staff has known that the 280 calories per gram isn't conservative. The real number is 230 calories per gram and that came out around 1980 when McDonald did an investigation based upon PBF test results and some SPIRT test results. So the real number is 230 calories per gram to ensure there's not a loss of raw geometry. Since then, since 1980, there's been tests at various facilities, CABRI and SRR, etc., where they've shown that there's been clad failure below the previously expected 170 calories per gram.

So that goes to my next subject and that's the dose. The dose is based upon the amount of fuel rod cladding that fails. Today we use two methods to determine clad failure. For BWRs, we assume 170 calories per gram and for PWRs, we use DNB. If they predict DNB to occur, they assume the clad fails and then the fissure product inventory that's in the fuel clad gap is released and that's used in the dose assessment.

For clarification, the CABRI test, none of the CABRI tests were done at higher than 200 calories per gram and they were predominantly looking to determine when PCMI clad failure occurred. The French weren't really targeting to determine when there was a loss of coolable geometry. The loss of coolable geometry was really dictated by the PDF test in the United States back in the '70s and there they had a reactor that was capable of putting that sort of energy deposition into the fuel rods and actually melting the fuel and melting the clad.

I don't believe that the French at CABRI or NSR or anyone really wants to melt the fuel and melt the clad. So they are really not trying to determine the loss of coolable geometry criteria. They're trying to determine the PCMI clad failure. So the coolable geometry failure limit of 230 calories per gram, the Westinghouse analysis is assuming 200 calories per gram which is below the 230 calories per gram. So that's conservative.

For their dose calculation, they're assuming a calculated DNB. Now I'm not that familiar with this case, but in a previous life when I worked for a utility out in Arizona, we used to assume DNB failure and we also used to assume a calories per gram failure for clad failure of 170. Even though it was determined to be the value for BWRs, we adopted it just to be conservative.

And just to give you a point of reference, we would calculate eight or nine percent of the fuel rods were in DNB, but we wouldn't calculate one rod was above 170 calories per gram. So DNB is much more limiting from a perspective of predicting or estimating how many pins fail, much more conservative than calories per gram.

So I think there's a little mix up between the 200. The 200 that was mentioned earlier although I wasn't in the room, but I've been told, the 200 calories per gram relates directly to coolable geometry and not to failure. The failure is based o n DNB.

MEMBER DENNING: I think at least from my view point the safety concern is the coolable geometry one but then there's the question of whether these most recent tests really are below this level where one would be concerned about coolable geometry or not. Dana, do you want to jump in here?

MEMBER POWERS: Yes, the presumption that coolable geometry is lost only when you melt is wrong.

MEMBER DENNING: That is true.

MEMBER POWERS: All you have to do is expel fuel and you've probably lost coolable geometry and what we see is a variety of tests demonstrating that that threshold for where you will get both fuel cladding failure and beyond that expulsion of fuel decreases with increasing burn-up. And after one cycle, it's all below certainly to 100. It's probably below 150. Arguable, but very low.

So the question is the Applicant comes in and says I get 178. That would suggest that he's vulnerable to a rod ejection accident. He goes on and says, when that's raised, he says, "I've done other calculations that are presumably not part of the application that show that it's even less than that." Well, that's good and I'm happy and I even actually probably believe those calculations, but nevertheless it's not part of the application.

So we're being asked to accept for power uprate something that any member of the public can go look and pull an article out of *Nuclear Safety* and say, "Gee, they accepted something that will fail if there's an accident." Why did we do that?

MEMBER DENNING: Okay.

MEMBER POWERS: Why should we do that? How would we defend ourselves in front of an energetic interrogation by a member of the public? I don't think I could.

MEMBER BONACA: And I would like to add that it's 30 years that very simplistic methods are being used like 1D calculation or whatever because it was licensed once against this criteria and since the members haven't been changing the books, they're still using this very rough calculation when all of them, the vendors, have much better methodology that they could use and apply to the -- Actually calories per gram would be much less than what they're calculating.

So we are left in this limbo here, indecision, because simply the better methods are not being used and the reason why they're not being used is the criteria that they are forced to are unreasonably high, 200 calories per gram, 280. I mean these are huge numbers.

CHAIRMAN WALLIS: This is not a power uprate issue. It's a more generic issue, isn't it?

MEMBER BONACA: I agree.

CHAIRMAN WALLIS: And we've known it for some time.

MR. CLIFFORD: Can I say something here? The staff is aware of this and just two months ago with the RIC we unveiled a strategy for dealing with this. We are going to by sometime this fall put out interim criteria which will be significantly below the 280 calories per gram which is currently in the Reg Guide and that will be based on an evaluation of all the test data that's available today and then we'll be doing a more thorough evaluation to revise Reg Guide 177 by the end of next year and that will include some very important tests that are going on this year that I hope will fill in some of the gaps that we have in the empirical database.

But to go back to what was said earlier, the 230 calories per gram, there's a lot of evidence that shows that's the right value at zero power as was mentioned and as you go up in burn-up that changes. Now today we're relying upon two things. The first thing is REAL (PH) 0401 which is published in 2004 by Research is essentially state of the art operability assessment which looked at all the data and came up with very conservative acceptance criteria which were based upon they collapsed the coolability line all the way down to the clad failure line.

So it went from, hold on one second. I have it right here. They assumed in this REAL 150 calories per gram at zero and then it dropped all the way down to about 60 calories per gram with burn-up and then they did a detailed three dimensional neutronics calculation to show that you just couldn't achieve that sort of change. So the conclusion was that not only would you not have an issue of coolable geometry taking into account all the burn-up effects and the corrosion effects, but you wouldn't even fail clad.

MEMBER BONACA: Yes.

MR. CLIFFORD: So we're relying upon that and we're also relying upon a fundamental understanding of the core in the sense that, yes, when you get a heavily corroded rod you lose ductility. So you're more susceptible to PCMI failure. However, when you reach that state in core life or in rod life, you just don't have enough power left in that rod to get that sort of impulse. The fresh rods are going to be the rods that give you the highest power pulse and those the cladding is very fresh. There's very little corrosion. It's very ductile. It can expand and absorb the fuel swelling.

MEMBER POWERS: The problem is when you have a corroded assembly next to a fresh assembly around the high worth rod. That's when you get into trouble here.

MEMBER SIEBER: So what do you expect the Applicant to do for this power uprate? He seems to be following whatever he thought was the correct procedure.

MR. FINLEY: This is Mark Finley again, Project Director. Let me just interject because the question was asked earlier what the result was for the pre EPU rod ejection analysis and I'd like Chris McHugh from Westinghouse to speak to that.

MR. McHUGH: This is Chris McHugh from Westinghouse. The pre EPU for the exact same case that Mark presented that gave 178 calories per gram, the result pre EPU was 176.3.

MEMBER MAYNARD: I think we have two issues here. One, I think that Applicant has clearly shown that and demonstrated that they have met the current requirements and I think that's through the staff review they've seen that and I don't believe that for power uprates that we're to be using generic issues to realize. If we think we have a real safety issue, a generic safety issue, then I think that falls into another category and I believe that from what I've heard and from what I understand with the conservatism, I think this is an issue that definitely needs to be pursued. But I'm not sure it's one that demands going outside the current regulatory process.

MEMBER DENNING: Why don't we --

MEMBER POWERS: So you're going to walk up to a member of the public and say, "Okay, here's this experimental data published in the open literature absolutely contradicts what I've accepted" and you're going to defend that. How? How do you persuade somebody that this is even a rational thing to do?

MEMBER DENNING: We're going to have this discussion later. Let's move on at this point because we know what the staff is saying. We know now what they're thinking and we'll have to really discuss later in detail as a committee just what we do about it. But at the moment, I think we know what all the positions are.

Agreed, Dana? There's no more that we're going to get out of the Applicant or the staff right now. We have to decide based upon that how we proceed. Okay? Why don't you go ahead then and move quickly through the balance of your presentation then.

MR. MILANO: Okay. I'm going to skip over the large break LOCA because we've already heard it and we also know that it's not limiting or excuse me, It is the limiting 1870 PCT and stuff and we've already talked about the fact that they've gone to what we consider to be the state of the art, the Westinghouse ASTRUM methodology.

Small break space, the staff reviewed the short-term behavior. They found that for small break that the results of the licensee's analysis were within the limits of the 50.4060 (PH) Appendix K results and we did do some confirmatory calculations in this area using the staff's RELAP Mod 5 Code and then we also had had a lot of interface with Constellation regarding the post LOCA long-term cooling. With that, I don't feel that there's anything more that we need to say since the licensee did go through it in a lot of detail and we did concur with that.

Mechanical impacts, again I'll go through this relatively quickly because we did evaluate the areas of both accelerated corrosion and fuel induced vibration. In this area, we did look at and we spent a lot of time looking at for specific systems, the systems that we felt, that the staff felt, most susceptibly. We did take a look at the temperatures, flow velocities, moisture content, etc. in those systems and compared those with industry norms for that type of system such as condensator feed or whatever and then we looked at what the licensee through its program expected, what components were expected to be affected by the increased EPU conditions and the fact that they were put into their FAC program.

We did look at the results of the licensee's CHECWORKS program and the models that are going to be updated based on implementing the EPU and we felt that at EPU conditions the FAC program does remain consistent with those industry guidelines such as the EPRI standards and stuff that were mentioned.

Flow induced vibration, as Constellation indicated, there was a lot of assessment done in this area. The staff did focus quite a bit both on the main steam and feedwater and condensate systems and noted that those systems are going to be instrumented at critical locations to monitor the vibration levels. Both was done at current power level and will be done during the power ascension testing.

The vibration monitoring was evaluated in accordance with the standard ASME Operating Maintenance Code 3 and then in particular and both

Constellation discussed today and it was discussed during the last subcommittee meeting, we spent a lot of time on the steam separator portion of the replacement steam generators and also on the U-tube portion of the tube bundle to make sure that nothing would be expected and this next slide just summarizes the staff's assessment of that area and the fact that although BNW Canada, their testing was done predominantly to looking at moisture carryover and was done just on a single separator module and stuff, as was indicated by Constellation, the flow rate that was tested for that by BNW Canada was well in excess of what the expected mass flow rate would be through a module at EPU conditions at Ginna.

And then going into the staff's review - Excuse me. If there isn't anything in the vibration and flow and corrosion areas, I'll go into the risk evaluations. For the risk evaluation, Ginna has used a PSA Level 1 which covers as we indicated before internal events including internal floods, external events and also shutdown operations. And it also uses a simplified containment event tree to evaluate WURF (PH) and then you'll follow NUREG CR 6595 for PWRs with large dry containments.

The staff did note with some pleasure the fact that the Ginna EPU risk evaluation did gain a number of insights and that those insights were translated into proposed plant modifications and other operational risk improvements that could reduce risk.

To further supplement your question that you posed to Constellation about the commitments, indeed Constellation did make a commitment and the staff has codified that in its safety evaluation and indeed as part of the recommended areas for inspection prior and post implementation of the EPU, that will be one of the areas that we're going to sample to make sure that all of those commitments were indeed accomplished. The staff's amendment process will indicate also that implementation, a full implementation of the EPU, will indeed be contingent on the completion of those commitments.

We've already talked in some detail about those five risk and cost beneficial changes that the licensee had made. So there's no need to go over those unless you have another question of the staff. And again, the PRA conclusions, licensee adequately modeled and addressed the potential risks. The risks are acceptable and in accordance with SRP Chapter 19, the staff believes that there is nothing in the proposed EPU that creates any special circumstances and that the licensee did identify potential changes that will be implemented that will reduce the risk that would be incurred by the uprate.

MEMBER BONACA: Did you do any verification with the SPAR model?

MR. MILANO: Donnie.

MR. HARRISON: There were a couple areas. This is Donnie Harrison from the PRA staff. There were a couple areas where we ran SPAR models primarily in looking at their seismic analysis. We did a couple of manipulations just to confirm that we would expect to get similar answers as the licensee got. We also did some things dealing with the seismic vulnerability that would affect shutdown operations just to show that it would be a small risk increase as well during shutdown. Yes, there were a couple places where we did that.

MEMBER BONACA: But you've gained some familiarity with their model or just compared some of the numbers or you don't know?

MR. HARRISON: It's a -- Any time you run a SPAR model or any kind of PRA model, you're going to get some familiarity with the plant and what kind of consequences you get from certain actions. So there was some gain in that.

MR. MILANO: I'm going to end up the staff's presentation with talking about what I would say are other key areas, not to say that those areas were key to our actual decision for acceptance. These were what I would say areas where we had a major focus, balanced plant, operator reactions, that's the human factors area, testing and then finally I'd like to talk a little bit about, because it came up last time, the proposed inspections during the actual implementation of the EPU.

In the balanced plant area, it was done in accordance, the staff's review was done in accordance, with Matrix 5 of the Review Standard which looked at a number of these areas as indicated here. In particular, the staff looked at the areas that would be affected by the increased decay heat loading, spent fuel pool cooling, the service water system and the auxiliary feedwater system noting that the service water system is important to cooling of the RHR heat exchangers and also the fact that the auxiliary feedwater minimum flow rates were going to be raised somewhere because of the EPU based on the transient and accident analysis. And then we spent a lot of time looking at operational considerations with regard to the feedwater and condensate systems.

Staff's results of this was the decay heat load will not exceed the cooling capability of the systems that are being relied on. Balanced plant systems don't pose an increased challenge to the reactor safety systems and that albeit I'm going to talk a little bit about the Power Ascension and Testing Program later, the review in the balanced plant area did have a lot of interface with the groups doing the power ascension testing. They provided a lot of input into that to make sure that that testing would encompass any of the issues that they were concerned about.

MEMBER DENNING: Incidentally, I would like you to jump now to 22 and talk about power ascension test program. The other two view graphs are pretty straightforward.

MR. MILANO: Okay. Again, the staff's review used SRP Section 14.2 which codifies the guidance that was provided in Reg Guide 1.68 for review of power ascension and testing. In terms of this, usually what's mentioned is large transient testing. The staff does not believe that there needs to be large transient testing done to assess the EPU. The EPU test program that will be instituted by the licensee does include sufficient testing to demonstrate that the structure, systems and components perform satisfactorily and the staff did consider and discuss on several occasions with the licensee and its vendor what was done in the original power ascension testing in the early '70s and the effect of the EPU on plant-related modifications that are being done now, how those would be tested and incorporated into the start-up test program.

The one thing of note in the power ascension testing that the licensee does plan to do is a manual turbine trip at 30 percent of the EPU power level to verify the plant's dynamic response and to also verify the control system settings such as pressurizer level and pressure controls, steam generator water level, and the rod control systems. And the --

MEMBER DENNING: I think that they did make a pretty good case that that 30 percent manual trip really is more important as a test than a full power trip as far as testing control system behavior.

MR. MILANO: That's correct and that pretty much is what the basis of our conclusion was. I did want to -- Although this is not really part of the review itself, it's a resultant of the staff's review. The staff will be conducting through utilization of the resident inspectors and regional specialist, they will be reviewing a number of things that the NRR staff recommends to verify the adequate implementation of the EPU. The regional staff will be using Inspection Procedure 71.004 which describes those things that are necessary for power uprate evaluations and it provides guidance to them with regard to how to conduct those inspections.

The staff did make a number of recommendations for areas of inspection, not to say that every single thing in there will be, every single recommendation will be fully implemented. We are in the process right now of discussing these recommendations and how they will be factored into the region's implementation of the inspection procedure, what portion of it needs to be samples, what levels will be sampled. That is ongoing right now.

They are considered to be recommendations as I said that will be used when selecting the sample. They don't constitute inspection requirements per se and I'd like to just mention a few items as an example. You know Constellation had indicated that there are some changes that are going to be made to the turbine bypass system, to the flow rates for both AFW and standby AFW and stuff. We have recommended that when those systems are being tested that that testing be monitored, that the results be reviewed and evaluated and stuff to make sure that the results substantiate the bases that the staff utilized in making its assessment, so those areas.

We're also going to look at other things like the actual mechanical overspeed trip of the main turbine and making sure that that overspeed trip test is going to be done at about 20 percent power and that is one of the areas that we're going to ask. Again, there are roughly -- And as you can see in the draft safety evaluation that was provided to you, there's about 12 areas with a number of subsets of them where we're recommending that the regional staff consider putting those into its inspection program.

With that, that basically concludes that staff's presentation.

MEMBER DENNING: Thank you. Do we have any other questions for the staff? Yes.

MEMBER ARMIJO: I have a couple of questions about the fuel. We didn't talk about that this morning.

MEMBER DENNING: No.

MEMBER ARMIJO: But the first question is this fuel, the 422 V+ design. Is that a new or unique fuel design? Is this the first time that's been used in -

MEMBER DENNING: I think that --

MR. VERDIN: This is Gord Verdin, a Principal Engineer at Ginna responsible for fuel. The 422 V+ product is actually a proven product. We have made some Ginna-specific enhancements and changes. Ginna has nine grids whereas the other plants that use 422 V+ fuel have seven grids. We've made some other changes, but all those changes are based upon improvements that have been done since the original 422 V+ product. So, no, it is a proven product.

MEMBER ARMIJO: Okay. The second part of my question is I know you've added a lot, stuffed a lot more fuel in there, more fuel length, more surface area, but have you increased the linear heat generation rate of the fuel assemblies or either peak rods?

MR. VERDIN: As a result of uprate obviously, the linear heat generation rate does increase. In order to mitigate a lot of these effects, we've done several things. The fuel assembly has substantially higher internal plenum volume for rod internal pressure issues. It's obviously a larger diameter rod which gives you the additional inventory plus it also gives you some DNB enhancement. But lastly, the fuel stack height itself has increased by 1.58 inches. That gives you obviously some mitigating in terms of peaking factors from our current fuel stack height.

MEMBER ARMIJO: So the peak linear heat generation rate hasn't gone up proportional to the uprate. It's gone up a little bit much but not much.

MEMBER SIEBER: Not the peak.

MR. VERDIN: It has gone up, but it is not proportional exactly to the uprate.

MEMBER ARMIJO: Okay. Thanks.

MEMBER SIEBER: Generally, those kinds of fuel designs, the idea is to get more pins to approach the peak and level things off which is what they did.

MR. MILANO: And one of the other things that was mentioned during one of the subcommittee meetings also was the pin diameter is going up and it is going up to a diameter that was consistent with, I believe, the RFA assemblies that --

MR. VERDIN: Actually the 422 pin diameter is consistent with the original Westinghouse standard fuel that was used at Ginna in Cycles one through eight and so there are some similarities to our previous fuel assembly.

MEMBER ARMIJO: Thank you.

MEMBER DENNING: Any more questions to the staff?

MEMBER SIEBER: We move from Vermicelli to --

MEMBER DENNING: Mr. Holm, would you then give us a wrap-up from your side? Let me ask you a question and it's a joint question for you and Westinghouse and it doesn't imply that we're really going to ask for this. But if we were to -- Westinghouse had implied that have done analyses with improved methods that show that in the rod ejection accident you'd have much lower heat content of the fuel and that they would not go to DNB. If we were to ask for that information, would you be able to provide it to us in a short period of time? I don't mean today.

MR. HOLM: I'm going to ask for a member of my staff to support me on this.

MR. FINLEY: Yes. Mark Finley and I'm going to ask Westinghouse to tell me what was done to-date and then I can respond to what time it would take us.

MR. HUGLE: This is Dave Hugle, Westinghouse, and what I can do is over the lunch break or as soon as we break here, I can contact the Pittsburgh office and see what might be available to present to you today.

MEMBER DENNING: Thank you.

MR. HUGLE: And if we can't present something today, certainly we'll see what we can do.

MEMBER DENNING: I'm not sure that we actually even can today. Could we today if we wanted to?

CHAIRMAN WALLIS: We can if you want to.

MEMBER DENNING: Yes, we can. Sure.

MR. HUGLE: I know we've presented results to the staff because obviously this was a big issue. We wanted to assure the staff that everything was okay in terms of, since all the plants out there, all the Westinghouse fleet, are using the 200 calorie per gram as a limit. So this is independent of Ginna or even the Ginna uprating here.

MEMBER DENNING: Very good. We'll expect to at least here back from you whether it would be possible.

MEMBER SIEBER: It's really not an EPU issue either.

MEMBER DENNING: Well, I think that's still to be -- That's something we're going to have to debate.

MEMBER SIEBER: If you change the power level, the calories per gram doesn't change very much. You may end up saying if I want to meet some vastly lower limit better not run your plant and you can say that to 30 or 40 plants.

MR. FINLEY: Yes.

MEMBER DENNING: Please proceed.

MR. HOLM: I would like to thank the Committee for the opportunity to present our application today. We've completed many detailed comprehensive reviews and they will continue through our construction and operating periods through our oversight processes. We've identified no new safety issues and a comprehensive testing plan and operator training plan will be performed in support of this uprate.

We're confident that Ginna's safety and reliability will be maintained as a result of our modifications, our procedure changes and operator training and oversight processes. And thanks to the Committee for the opportunity.

MEMBER DENNING: Thank you very much. Any other questions for the utility? Then thank you and again, I'd like to thank you for your presentations and your staff and also to the staff of the Nuclear Regulatory Commission for their presentations. Thank you very much. Back to you.

CHAIRMAN WALLIS: We will now take a break until the schedule for the next presentation which is at 1:15 p.m. I want to keep us on schedule because we have a lot of work to do and we have a short meeting. So we'll have a slightly shorter lunch but not much shorter. 1:15 p.m. Off the record.

(Whereupon, at 12:25 p.m., the above-entitled matter recessed to reconvene at 1:16 p.m. the same day.)

CHAIRMAN WALLIS: On the record. The next item on the agenda which is another extended power uprate, this time an application from Beaver Valley Nuclear Plant.

MEMBER DENNING: Do we know anything about this plant?

MEMBER SIEBER: Where?

CHAIRMAN WALLIS: Rich Denning will again lead us through the process. Rich, are you ready?

MEMBER DENNING: Yes. Now we're going to be considering two smaller uprates at the two units at Beaver Valley and I'm going to turn it over to Tim Colburn to lead us off here. Thank you.

MR. COLBURN: Dr. Denning, Dr. Wallis. My name is Tim Colburn. I'm a Project Manager in the Division of Operating Reactor Licensing assigned to the Beaver Valley Power Station, Units Nos. 1 and 2.

MEMBER SIEBER: Could you pull the microphone a little closer to you? Thank you.

MR. COLBURN: Yes, I'm sorry. I'm here to discuss the Beaver Valley extended power uprate of eight percent and the agenda topics we'll be discussing this afternoon will be licensing introduction. Lead speaker for the licensee is Pete Sena, the Director of Site Engineering. With him with be Mark Manoleras, Ken Frederick, Mike Testa and Colin Keller who will discuss PRA. We're discussing plant modifications, safety analysis, mechanical impacts, risk assessment, implementation and summary remarks.

The licensee had several amendments as pre application amendments necessary to support the power uprate. These included containment conversion to the atmospheric conditions for both units. This involved approval of MAAP DBA, computer code for mass energy release. Beaver Valley 1 relies on containment overpressure protection for pumps. Beaver Valley 2 does not. Staff performed independent mass energy release calculations and had good agreement with the licensee results and steam generator replacement for Beaver Valley 1 only was also accomplished.

The October 4, 2004 application had numerous supplements in response to staff REIs and included a request for full alternative source term implementation. The staff review followed the Review Standard RS 001 Rev 0. At this point, I would like to turn it over to Pete Sena from the Licensee Staff to begin their presentation.

MR. SENA: Thank you, Tim. Good afternoon, Mr. Chairman and distinguished members. I am Pete Sena. I'm the Director of Site Engineering at Beaver Valley. This morning I would like to provide a brief introduction and some background to the Beaver Valley power uprate.

Our desired outcome is to provide you with sufficient information and answer all relevant questions regarding the Beaver Valley power uprate so that you may form the appropriate positions and recommendations to the NRC Commissioners. We've built this presentation to cover a number of areas affected by the uprate and areas that we believe are of interest to the Committee in fulfilling the desired outcome of these procedures.

Today's agenda has already been covered by

Mr. Colburn and the members of Beaver Valley. So I will not reiterate that. I will be covering the Beaver Valley history with respect to our power history, the Beaver Valley comparison with our peer units with regard to our power and our preparations for the uprate.

Beaver Valley units are a three loop Westinghouse PWRs that achieve commercial operation in 1976 for Unit 1 and 1987 for Unit 2. The original core license power level was 2652 megawatts thermal. The 1.4 percent current uprated power of 2689 megawatts credited the improved feedwater flow measurement uncertainties. The larger power uprate approximately eight percent was initiated in mid 2000 and used an initial scoping phase to determine the best approach and the optimum target license power level. As a result of the scoping evaluation, a target reactor power level of 2900 megawatts was selected.

As you can see, this target value aligns us very well with our peer three loop Westinghouse units that have previously uprated. We benchmarked closely these units' approach to uprate and their operating history since their implementation. We feel that collectively using the experience of these stations gives us confidence in the approach that we have chosen.

As you can see here and Mr. Colburn already covered this, but there were several license amendments which preceded the uprate application. Two key components of the uprate are the containment conversion and the best estimate LOCA amendments. These amendments were approved by the NRC in the first quarter of this year.

The atmospheric containment provided an industrial safety improvement to allow for frequent and safer containment entries while at power. The Beaver Valley containment design pressure of 45 psig is not being changed nor is the containment structural design temperature of 280 degree being revised. The containment conversion project incorporated all changes due to the EPU application and the steam generator replacement projects at Unit 1.

Also the best estimate LOCA methodology was applied to the EPU. This is the same model currently in use by other stations throughout the country such as Braidwood, Byron and Indian Point. BELOCA and that's the code retract methodology is the preferred methodology for Beaver Valley needed to support the uprate.

BELOCA and containment conversion have been implemented at Unit 1 during this past Unit 1 spring outage and will be implemented at Unit 2 following our Unit 2 fall outage. Finally, the replacement steam generator amendment was implemented this past spring.

As you can see from this picture, at Unit 1, we have just replaced our steam generators with Model 54F units and these units were designed for the uprate application. The reactor head was also replaced with a simplified, modified design. Additionally, new control rod driver mechanisms were installed. This outage was recently accomplished as I said about two or three weeks ago and was completed in a 65 day time period.

Again, this was a Beaver Valley site-led project. The ownership remained with us at the site. All of our speakers are site individuals. We provided the overall management and direction. Beaver Valley reviewed and approved the design inputs and performed detailed owner acceptance of each vendor calculation. Our support teammates of course did include Westinghouse and Stone & Webster, many of whom are here today as subject matter experts and may be called upon.

Our corporate offices provided oversight for the project to make sure that we met quality assurance requirements. Additionally, independent assessments of our safety analysis were completed by MPR and Associates. That completes my introductory remarks. Next I would like to introduce Mark Manoleras. Mark is our Manager of Design Engineering at Beaver Valley.

MR. MANOLERAS: Thank you very much, Pete. As Pete had mentioned, I've been at Beaver Valley for the past 18 years. I've been the Design Manager at Beaver Valley since 2002. My department has ownership of the safety analysis and modification packages associated with this power uprate. I'd now like to discuss those modification packages.

We replaced our charging safety injection pump rotating assemblies at each unit. This is going to extend the pump burnout flow limit and will improve our high head flow capacity to improve small break LOCA PCT results. We added new feedwater isolation valves at Unit No. 1. This reduces our containment pressure and temperature falling of main steam line break inside containment. This brings our Unit No. 1 up to the same design as our Unit No. 2.

We added aux feed cavitating venturis at

Unit No. 1. Again, this brings our Unit No. 1 up to our Unit No. 2. This will minimize mass addition input into the containment and reduce aux feed flow on a feed line break and will maintain the minimum flow to the intact steam generator.

We are adding a reactor cavity drainage port at both units. This will facilitate post accident draining of the cavity to improve NPSH performance of the pumps that draw from our containment sump. And we replaced our steam generators at Unit No. 1.

For secondary side modifications, we are replacing our high pressure turbine at Unit No. 1 and Unit No. 2 with an all-reaction design. We are going to install stakes in our main condenser in Unit No. 2. We already have those stakes at Unit No. 1. We are raising the set pressure of our MSR relief valve set points at both units. We are increasing the Cv of our main feedwater control valves. At Unit No. 1, we made control valve trim changes and at Unit No. 2, we're in the process of replacing those control valves.

We replaced our turbine generator rotor and statter at Unit No. 1. The existing rotor had a short and we replaced that. We wanted to replace it prior to power uprate and we've completed that modification. Additionally, we replaced several instrument sets and we replaced these instrument sets due to the higher flow range required needed to take a look and be able to monitor the parameters.

If there are any questions, I'll take those at this time.

MEMBER DENNING: No, I think we're fine.

MR. MANOLERAS: I would like to now introduce Ken Frederick who will talk about the plant safety analysis.

MR. FREDERICK: Thank you, Mark. As Mark said, my name is Ken Frederick and I'm the Lead Safety Analyst at Beaver Valley plants. I have been at Beaver Valley for 27 years and for about 24 years, I've worked in the Engineering Department primarily in the safety analysis area and for the last five years, I've been involved with the containment conversion and the uprate projects.

For the safety analysis discussion here, I guess the criteria or the objectives here are to basically demonstrate that the analyses meet the regulatory limits and that Beaver Valley will operate with adequate safety margins at the EPU conditions.

So for this discussion reduced from the last meeting we had, we had a lot more detail, but we'll go over again the operating parameters at the EPU condition, touch on the methods and the methodology changes that have been part of this project and look at some of the results for non LOCA and LOCA events as well as the long term cooling and touch on the containment analysis. Again, the containment and also the large break analyses were actually part of separate submittals which have been approved earlier this year.

This slide shows the nominal operating parameters for Unit 1. Again, these are more best estimate type in our target values for our operation at the EPU conditions. We've actually analyzed over a range of T_{avg} from 566.2 to 580 degrees. So that establishes our operating window. But again, our intent is to operate at these conditions primarily because this is what we've optimized our high pressure turbine replacement at the steam pressure shown here.

The flow here from pre EPU to EPU does not change the thermal design flow. It remains at the current value, so the increased output from the core as a result of increased temperature rise.

These are our similar values for Unit 2. One thing to note here is that we're actually planning to reduce T_{avg} a couple degrees and this is to keep our hot line temperatures below 610 and this is primarily material concerns since we do still have Alloy 600 tubes in the Unit 2 steam generators.

MEMBER SIEBER: So the enthalpy rise across your reactors is about the same.

MR. FREDERICK: No, it will actually increase about seven or eight percent.

MEMBER SIEBER: Or eight percent.

MR. FREDERICK: Right.

MEMBER SIEBER: Okay.

MR. FREDERICK: This slide shows the methodologies that we used for the safety analyses and you can see there the change from the current, the ones that have changed, rather the large break where we're using BELOCA methodology now. This is the original Westinghouse methodology, not ASTRUM. That's the more updated one.

For non LOCA, we've switched the DNBR calculation to the NRC approved VIPRE code. Previously, we used THINC. Then we have gone on to MAAP as part of the containment conversion program. I'll discuss that a little bit later.

In the dose assessment area, we've gone to a full implementation of alternative source term as well as using ARCON 96 for the chi over Q's. In the non LOCA area, it lists here the condition to acceptance criteria, key ones being DNBR limits, heat generation limits, RCS and secondary pressure limits at 110 percent and criteria that Condition 2 should not escalate into a Condition 3 or 4 event.

Condition 3 and 4 criteria are a little less stringent. Some fuel damage is accepted and dose results need to remain within the limits. I might note that for the EPU program none of the events have changed categories.

This slide shows the DNBR margin in kind of a pictorial representation. Again at the bottom 1.0 for DNBR is critical reflux and the correlation limit which is a number that's actually in our tech specs is 1.14. The Beaver Valley design limit is 1.22 and that's adding in the process uncertainties for pressure flow, temperature. And our safety analysis limit that we used for Beaver Valley for the EPU was 1.55. So you can see there's about 21 percent margin retained between the safety analysis limit and our actual design limit.

And primarily that is because when we started this program we were in a transition on our fuel. So we had some transition core penalties which have since gone away since we're all in the RFA fuel now. At this point, we have a fair amount of margin in our safety analysis which is good considering that we do have results that are fairly close to the limit. We see here the DNBR events which are events which for DNBR is a primary limit.

Some of these use different correlations and those things depend on what kind of event it is. If it's a zero power, for example, we would use a different correlation than WRB-2M. WRB-2M is associated with the RFA fuel and this is the first application at Beaver Valley. That was part of the licensing change and that takes advantage of the IFM to the immediate fuel mixers on the RFA fuel assemblies which provides some thermal hydraulic margin and for that reason, we did regain margin with these analyses that EPU has taken away.

MEMBER SIEBER: I take it you could not have done an uprate of this size had you not changed the fuel.

MR. MANOLERAS: Limited in thermal hydraulic space?

MEMBER SIEBER: Yes.

MR. MANOLERAS: I'm not sure. Chris McHugh.

MEMBER SIEBER: It doesn't look like you

have a lot of excess margin.

MR. MANOLERAS: Probably did not while we were doing the transition.

MEMBER SIEBER: Right. Okay.

MEMBER DENNING: But notice that their criterion here is 1.55 versus 1.38 that we discussed the last time. So there's something there.

MEMBER SIEBER: Yeah, but in licensing space, you don't count that margin, you know. It's deterministic. 1.55 is it and to get more room to operate you have to reapply to the agency to change the safety limit.

MEMBER DENNING: I don't quite understand what you're saying, Jack, because I mean the 1.38 was at the choice of --

MEMBER SIEBER: Ginna.

MEMBER DENNING: Ginna.

MEMBER SIEBER: Right. This is their choice here.

MEMBER DENNING: And that's their choice. Right.

MEMBER SIEBER: Right. But once you chose it and the staff approves it, that becomes a firm number and to change the number the staff has to approve the different one.

MR. MANOLERAS: As noted here, the limiting event is the rod withdrawal power at 1.57 for Unit 1 and the other note here is that the steam line breaks which are actually Condition 4 events are analyzed to Condition 2 criteria as a conservative measure.

This slide shows some of the events which the challenge the pressure limits and here for the Condition 2 events which are noted by the pressure limit of 2748.5 psia the limiting event is the loss of load and we'll talk about that a little bit more. And the locked rotor has a limit of 120 percent design which is a Level C criteria or ASME level C and that also has the specific limit associated with it and the analyses show that we meet these limits.

Discussing the loss of load, we actually had a loss of load event recently in early April and if you look at the blue line on the slide there, that's the actual plant data. The red line is actually a LOFTRAN. That's the thermal hydraulic code that we use for non LOCA events. That analysis is crediting all the control systems which are not normally credited in the safety analysis. So the safety analysis result shows in increase in pressure of around 500 pounds. If we credit control systems and run the analysis the pressure goes up about 100 psi.

CHAIRMAN WALLIS: Do you have anything about this calories per gram issue and rod ejection loads coming up?

MR. MANOLERAS: Yes, the next slide.

CHAIRMAN WALLIS: Okay. I just wanted to know.

MR. MANOLERAS: The point of this slide was to demonstrate the level of conservatism in this particular non LOCA analyses contrasting essentially no pressure increase at all with the 500 pound increase predicted by the Code and that's the effect --

CHAIRMAN WALLIS: In strange units here, BTUs per pound. What is that?

MR. MANOLERAS: Chris, could you jump in here? The conversion from BTU per pound to calories per gram that would work to about 180 calories per gram for the results here of 326.8.

MR. McHUGH: The question was asked this morning about the pre EPU value for Ginna. The pre EPU for Beaver Valley was 180 and the post is 181.6.

MR. MANOLERAS: The other note on this slide --

MEMBER POWERS: So I burn up fuel clear across the coolant. Right? Roughly speaking.

MR. MANOLERAS: Was there a question there?

MEMBER POWERS: Not really.

MR. MANOLERAS: Okay.

MEMBER DENNING: It's a statement.

MEMBER POWERS: One hundred eighty calories per gram will blow your -- up, your third cycle fuel completely off, bust the clad and --

MR. MANOLERAS: And this is again a conservative 1D analysis. The other events listed on this slide --

CHAIRMAN WALLIS: Well, it doesn't sound very conservative if it's going to challenge the fuel.

MEMBER DENNING: He said the analysis was conservative. He didn't say the criterion was conservative.

MEMBER POWERS: It's only a prediction.

MR. MANOLERAS: The pressurizer --

MEMBER POWERS: -- pounds of fuel to 180 calories per gram is not a prediction.

VICE CHAIRMAN SHACK: That's true.

MEMBER SIEBER: If it got there.

MR. MANOLERAS: We look at the pressurizer filling for several events as listed here. For the spurious safety injection, we actually see the pressurizer fill and we talked about this event in some detail at the last meeting. But essentially what that causes us to do is to make sure that the safety valves and the power operator relief valves will be able to pass water and successfully reclose following reset of the pressure signal.

To conclude for the non LOCA, as we showed the DNBR, the limits, safety analysis limits have some substantial margin between the design and the actual safety analysis limit that we use. The analysis that we do to look at peak pressures in the system are very conservative and we're comfortable with the results. And again, all the acceptance criteria for all the Conditions 2, 3 and 4 events are met at EPU conditions.

Moving on to LOCA, summarized are all the PCT values here for both large break and small break as well as the pre EPU values that are shown there and you see that EPU does not demonstrate a substantial increase in the temperatures and primarily this is because of the modifications that we made in the plants. For the large break, this analysis tends to be very sensitive to containment back pressure. In the containment conversion program, we've actually raised the initial pressure containment around four pounds. So there is some benefit there as well as going to BELOCA technology. It also shows us some benefit.

In the small break area, again we've increased the safety injection flow from our high head system by approximately five percent by changing out the pumps and that provides us some offset of the change due to EPU.

VICE CHAIRMAN SHACK: Now are these both calculated with the new best estimate model?

MR. MANOLERAS: No, the small break is done using the current NOTRUMP.

VICE CHAIRMAN SHACK: But in the large break, the current and EPU. Now are they both --

MR. MANOLERAS: No. The current is actually using the Appendix A models.

CHAIRMAN WALLIS: Are you the folks who came close to Co Y (PH) oxidation limit?

MEMBER DENNING: Yes.

MR. MANOLERAS: Yes, for the core -- we were close.

CHAIRMAN WALLIS: Are you going to show that? I don't see a slide on that.

MR. MANOLERAS: I don't have that in my slides.

CHAIRMAN WALLIS: That seemed to be remarkably --

MEMBER DENNING: Do you happen to remember those values because I think we ought to mention those?

CHAIRMAN WALLIS: Who asked you about that?

MR. MANOLERAS: Yes, we can pull them up here real quick.

MEMBER DENNING: Okay. I think for one thing it was clear and that was the percent hydrogen was one percent which was essentially the criterion. But we were presented with some discussion by Westinghouse that indicated that the reason it was one percent was the result of a very conservative analysis and because it was so conservative they didn't press it.

MR. MANOLERAS: The results could be lower if we pursued it further I guess is the way it was.

MEMBER DENNING: And I think that's pretty obvious that that was the case.

MR. MANOLERAS: Yes. For the large break, the local cladding oxidation is 8.7 percent for Unit

1 and 6.7 for Unit 2. Again 17 percent is the criteria there. For the core wide for Unit 1, it's 0.98 percent and for Unit 2, it's 0.91 and again this is typically the way the analysis is done is we perform a very conservative analysis and if the results come in within the acceptance it's not pursued further even though there are margins that could be put in there if we did further work.

CHAIRMAN WALLIS: You guys are also very conservative, are you?

MEMBER DENNING: They seem to be careful up until that last "very." But one thing that's clear is that these guys have always been sitting in on the Ginna presentations so they always know the things that --

CHAIRMAN WALLIS: I'm just wondering if they are only conservative if they would be acceptable. They would have to very conservative.

MEMBER SIEBER: Or very, very conservative.

MEMBER POWERS: You're being difficult, Graham.

MR. MANOLERAS: Moving on to long term cooling, similar to Ginna, we had some questions from the staff that we needed to address and we had to essentially redo the analysis to take into consideration the issues listed here, core voiding, system effects and pump -- that we were going to credit --

CHAIRMAN WALLIS: This is another area where we have some feeling that the staff ought to sort things out better, isn't it?

MEMBER DENNING: Yes. There is high reliance here on the BACCHUS experiments as indicative of a mixing that occurs with some fraction of a lower plenum and all the analyses that we're seeing take that credit without doing a very good analysis of the BACCHUS experiment or using tools that one could use in a more realistic way to better analyze this is my impression.

MR. MANOLERAS: I'm not sure if anybody from Westinghouse mentioned it but the PRAs owners group has a program approved to actually work with the staff to --

CHAIRMAN WALLIS: That's right. That's another one of those things where the staff is working on doing things better and we want to see it happen. But now we're asked to approve this without knowing what is going to come out of this new evaluation.

MR. MANOLERAS: Yes, this analysis has

credited 50 percent in the lower plenum based on the --

CHAIRMAN WALLIS: It's the number between zero and one.

MR. MANOLERAS: Yes.

MEMBER POWERS: Fifty percent is not between zero and one.

CHAIRMAN WALLIS: Yes it is. Fifty percent is a half.

MR. MANOLERAS: So the results for Beaver Valley we show the switchover time required to go to hot leg injection for Unit 1 is 6.5 and for Unit 2 it's six hours and for small breakers, we've also done analyses to address an additional question to basically show that the systems are capable of cooling down and depressurizing within the required switchover time.

In the containment area, again we have recently got approval for our containment conversion program and essentially what that does is allows us to operate the containment at about four psi higher, still slightly subatmospheric. This analysis benefitted from some modifications we made in the plant, the replacement of steam generators for Unit 1.

CHAIRMAN WALLIS: You've told us the

subcommittee that this was entirely for the benefit of the personnel who had to go into the containment.

MR. MANOLERAS: That is certainly one of the major benefits.

CHAIRMAN WALLIS: There was no technical reason.

MR. MANOLERAS: That does actually give us some PSH margins.

MEMBER SIEBER: It helps the pumps in PSH.

CHAIRMAN WALLIS: Does it work? It does not help. Doesn't it make it worse?

MEMBER SIEBER: No.

MR. MANOLERAS: It actually improves the PSH margin.

CHAIRMAN WALLIS: Because you get a higher pressure when you -- Okay.

MR. MANOLERAS: We put new feedwater isolation valves as Mark said that eventually helps out with our steam line break and the drainage port helps out with the inventory in the sump.

CHAIRMAN WALLIS: That means that you get water from the reactor cavity into the sump.

MR. MANOLERAS: Yes. Previously we were holding up 25 gallons or something.

CHAIRMAN WALLIS: And then there's

something about the probability of blocking that hole.

MR. MANOLERAS: Pardon me?

CHAIRMAN WALLIS: Did you know something about the probability of blocking that drainage?

MR. MANOLERAS: It's about a one foot diameter. Is that right?

CHAIRMAN WALLIS: The hole doesn't have a screen on it or anything.

MR. MANOLERAS: There is no screen on it.

CHAIRMAN WALLIS: A big hole?

MR. MANOLERAS: It's basically a hole that we did deliberately skew it so that we don't have streaming problems from radiation. But it's basically just an open hole, yes.

All the analyses again show that we remain within the current design pressure of 45 psig in the design temperatures. For Unit 1 for the recirc spray pumps we do credit containment overpressure and that is part of the current licensing basis as well.

MEMBER DENNING: And you should mention what the duration is that's required in the magnitude of the overpressure.

MR. MANOLERAS: Right. The overpressure is required for the first 20 minutes after the pump starts.

MEMBER DENNING: That's pretty small.

CHAIRMAN WALLIS: As I recall, that's exactly the same curve as you had before the uprate. There's essentially no change in the --

MEMBER SIEBER: Right.

CHAIRMAN WALLIS: What you're asking for is close to what you had before, isn't it?

MR. MANOLERAS: Right. The time duration only increased I think it was around a minute and the pressure a pound.

CHAIRMAN WALLIS: What are the green and red here?

MR. MANOLERAS: The green and the red are the required containment overpressure for inside and outside recirc spray pumps.

MEMBER DENNING: And the blue is what's available.

MR. MANOLERAS: The blue is --

CHAIRMAN WALLIS: I thought you have a curve of what you had before the uprate but maybe you don't.

MR. MANOLERAS: I did not include those slides in this package.

CHAIRMAN WALLIS: But it's very much the same, isn't it?

MR. MANOLERAS: Yes, they are very similar.

MEMBER DENNING: And you should also mention the tests that were performed on the pumps and their ability to pump without failure.

MR. MANOLERAS: Right. We actually have run the pumps at degraded MPSH conditions in our test program dating back to the late '70s. Actually, they were North Anna pumps, but ours are identical and that test showed that the pumps could operate at reduced MPSH down to, we ran them down to about four feet available and the pumps ran in a stable condition and post-run tear-down showed no damage to the pump. So even under reduced MPSH conditions, we're confident that the pumps will operate.

MEMBER KRESS: Were they cavitating severely?

MR. MANOLERAS: They were cavitating, yes.

MEMBER POWERS: And how long did you run them?

MR. MANOLERAS: I think most of those runs were around a half hour.

In conclusion, all acceptance criteria for the safety analysis are shown to be met at EPU conditions and the effects of some of the plant modifications, we may benefit the analyses and help to offset the change in safety margin that would occur from EPU.

CHAIRMAN WALLIS: What do you mean by "maintain safety margin"?

MR. MANOLERAS: Well, for example, in the case of large break LOCA, we see PCTs that are not changing much from pre EPU to EPU and again those are benefitted by some of the modifications.

CHAIRMAN WALLIS: By safety margin, you mean the difference between 2200 and whatever you predict.

MR. MANOLERAS: That's correct, yes.

CHAIRMAN WALLIS: That was using a new technique.

MEMBER DENNING: Yes, that's really a selection of examples.

MR. MANOLERAS: A better example might be the small break analysis because that one really does benefit from direct changes we've made to both the charging pumps and the accumulator pressures.

CHAIRMAN WALLIS: Actually if you'd use the BASH method you've shown that you didn't have the safety margins.

MR. MANOLERAS: Potentially yes.

CHAIRMAN WALLIS: This "maintain safety margin" is a term that's used rather loosely I think and you have to be careful about its use. At least you're below the limits. That's what matters. If we started really checking what you'd changed in margin, we'd be here for a long time I think.

MR. MANOLERAS: Any other questions?

MEMBER KRESS: Have to develop some new -- to do that.

MEMBER DENNING: Any more questions related to safety analysis?

MR. MANOLERAS: I would like to introduce Mike Testa. He'll go over the mechanical impacts.

MR. TESTA: Yes. Thank you, Ken, for that introduction. I would also like to thank the Committee for the opportunity to be here today. As Ken said, my name is Mike Testa. I'm the Extended Power Uprate Project Manager for Beaver Valley. I've been at Beaver Valley for 24 years. I came up through the Design Department. I've been assigned as the PM, Project Manager, for the last five or six years and also I manage the related submittals that were put in place to lead up to the uprate.

Today I'll be discussing the mechanical impacts. I'll talk about steam generator vibration, piping and component like the balance of plant heat exchangers vibration and flow accelerated corrosion.

The first thing here is the steam generator two bundle region that was evaluated. As was discussed earlier in the presentation on the Unit 1 just this spring a few weeks ago, we replaced the steam generators from a Model 51 to a Model 54F. Steam generators are designed for the uprate condition.

For Unit 2, we're continuing to utilize the existing Model 51 steam generators. They were reviewed for flow induced vibration effects which showed acceptable results. We also looked at unsupported U bends for increased fatigue and under this evaluation, there were six tubes that were required to be plugged or taken out of service and that was already done. And we also looked at increase in tube wear at the anti-vibration bar interface which was evaluated and also shown to be acceptable.

VICE CHAIRMAN SHACK: What's the material on your Model 51?

MR. TESTA: Six hundred.

VICE CHAIRMAN SHACK: ET or 600?

MR. TESTA: I'll let Greg Kammerdeiner answer that.

MR. KAMMERDEINER: This is Greg Kammerdeiner from First Energy. It's Alloy 600 low temperature milled.

MR. TESTA: Going on, as far as the steam generator, steam dryer for the secondary steam dryer, we are aware of the issues with the BWR dryers. Now what we did here was look at the secondary separators for our Model 51 and 54 steam generators and I think the bottom line, the conclusion there, is that the way that the steam flow comes up through the secondary dryers, the velocities are low. They are on the order of 3.5 to 4 feet per second; whereas the BWR they are on the order of 100 feet per second in the area or in the region where they've had problems with cracking.

Again the comparison between the Model 51 and 54, the 54 is comparable velocity and basically, the bottom line is that the PWR secondary steam dryers have not exhibited any operational issues in the industry.

As far as the balance of plant exchangers again we looked at the increased flow, change in parameters, thermal dynamic parameters through the heat exchangers. It shows that the feedwater heaters, moisture separator reheaters, were acceptable. As far as the condenser, it was mentioned previously that our

Unit 1 condenser was previously staked. We will doing that on Unit 2 before we increase power.

Vibration monitoring, secondary piping systems, we're going to monitor the secondary systems pre EPU and that's going to include a baseline walkdown for each of the plants which we have done that at the 100 percent pre EPU level. Areas of interest will be targeted for inspection and what we're doing here is we're going to utilize the guidance from ASME OM-3. Going forward as we escalate power, we're going to collect and review data at each power ascension plateau. We will augment the inspection with the vibration monitoring equipment as required and just the last bullet here is just a note that we have large equipment, for example, the reactor coolant pump and the turbine which is continuously monitored with the existing installed plant instrumentation.

Just a final thing here to wrap up on flow accelerated corrosion, we have evaluated the impact of the uprate on our flow accelerated corrosion program. The EPU effects were evaluated using CHECWORKS. Just a second bullet here, just a note, turbine extraction steam teeth, one in each unit at comparable locations were replaced and that was done proactively.

The next item here is the post uprate outage inspection sampling will be increased based on the EPU and piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates.

MEMBER POWERS: I'm puzzled just a bit about bullet number two. You did that because you detected something in CHECWORKS that was bothersome.

MR. TESTA: Yes. We're going to let Dave Grebski. He's our program.

MR. GREBSKI: Yes, Dave Grebski, First Energy. The MSR relief valves set point was increased to 260 pounds. Therefore the design pressure increased in that system. So the margin between the measured thickness and the required was cut into. So as Mike said, we proactively replaced that. Upgraded with chrome mollie material because it was undergoing some thinning.

MR. TESTA: Okay. If there are no other questions, that concludes my part of the presentation. I would like to introduce Colin Keller. He's our Supervisor of our PRA group. Colin.

MR. KELLER: Mike, thank you for that introduction. As Mike said, my name is Colin Keller and I'm the Supervisor of the PRA group at Beaver

Valley. Today I'd like to talk about the elements of the PRA model that were reviewed for EPU conditions, initiating event frequencies, success criteria, equipment failure rates and also operator response times and also discuss the changes that resulted in core damage frequency and large early release frequency.

CHAIRMAN WALLIS: You're going to use CDF from LERF. This is a plant which is closer to a population center than almost all other plants. Isn't that?

MR. KELLER: I don't know. I can't speak for all other plants. We are relatively close to the Pittsburgh area.

CHAIRMAN WALLIS: It's pretty close to. Yes, so this isn't really part of what you have to evaluate. It's just my curiosity. How close is it to Pittsburgh because this is obviously some element of risk associated with it?

MR. KELLER: I believe it's approximately 35 miles.

CHAIRMAN WALLIS: Thirty-five miles.

MR. KELLER: Somebody can correct me.

MEMBER SIEBER: Thirty.

CHAIRMAN WALLIS: Thirty. So the center

of Pittsburgh which is a fairly big city.

MEMBER SIEBER: It's getting smaller.

MR. KELLER: Okay.

(Several are speaking at once.)

MEMBER POWERS: Moved out. It may become more attractive now.

MEMBER SIEBER: Went down by two not too long ago.

MEMBER POWERS: The age increased when Jack left.

CHAIRMAN WALLIS: But if people are all moving to the suburbs then they would be closer to this reactor, wouldn't they?

MEMBER SIEBER: So did the ugliness factor.

CHAIRMAN WALLIS: Okay. We'll move on.

MR. KELLER: Looking at our initiating events as a result of our review for the extended power uprate, there were no new initiating events identified and also there were no significant increases in the initiating event frequencies due to the extended power uprate.

For our success criteria, we used the MAAP code to perform the analysis to establish that criteria and also identified that there were no accident sequences that resulted from the extended power uprate. Our component and system reliabilities with comprehensive reviews of the equipment was performed. We found that the systems will operate within the allowable limits and that the impacts on PRA failure rates, there was no impact on the PRA failure rates or results. In the area of operator response times, again we used the MAAP analysis to determine operator action time available and did find that as a result of the higher decay heat that some of those times had reduced for operator actions.

This is a table for Unit 1 showing the resulting changes from pre EPU to post EPU for total core damage numbers as well as internal, external and fire and also for total LERF. As you can see, the changes in risk were relatively small compared to the original risk.

VICE CHAIRMAN SHACK: There are nominally changes in risks though. They're just changes in frequency.

MR. KELLER: There were some additional modifications that were made especially at Unit 1 where you added additional equipment like cavitating venturis fast acting feedwater isolation valves. so there were some additional failure probabilities due to those equipment, but those overall impacts were very small.

MEMBER POWERS: There's also an increase in the inventory of releaseable radionuclides that amounts to about eight percent. That's not reflected in those numbers.

MEMBER SIEBER: Yes.

MEMBER POWERS: Why are they meaningful to us? I mean if we do a power uprate and we look at the change in risk, we don't look, the one that that's absolutely guaranteed to go up.

MEMBER KRESS: Number 1, the inventory would affect the LERF that you think is a surrogate for the QHO.

CHAIRMAN WALLIS: That's right.

MEMBER KRESS: And Number 2, the percent increase in fission products means the societal risk is increased by that much.

MEMBER POWERS: But that's not reflected in these numbers.

MEMBER KRESS: Not in any of these numbers, that's right.

MEMBER DENNING: Which is a good reason why we don't use PRA to these in a risk inform.

MR. KELLER: This is not a risk informed

application. It's kind of a --

MEMBER DENNING: Because I don't think PRA --

MEMBER POWERS: I'm not terribly concerned about his application right now. I'm concerned about what our responsibilities are to advise the Commission on what its responsibilities are and here we're going up and we're advertising to the world that we're making something like a one percent change in risk when in fact we're making almost ipso facto, a guaranteed eight percent change in risk. Without any analysis at all, I can come up with roughly eight percent here. We're just kind of lying here, aren't we?

CHAIRMAN WALLIS: I usually call it change in CDF and LERF.

MEMBER DENNING: We should certainly --

MEMBER SIEBER: These numbers reflect the risk but the consequence.

MEMBER DENNING: No, I wouldn't say so. I think that Dana is right. I mean the risk is --

MEMBER SIEBER: To an individual.

MEMBER KRESS: Two plants is on the site so it's 16 percent.

CHAIRMAN WALLIS: No.

MEMBER POWERS: No, it's still eight percent. An eight percent increase totally.

MEMBER SIEBER: Only one at a time is melting.

CHAIRMAN WALLIS: This is a point we've made many times before I think.

MEMBER DENNING: Yes, it is and I think that you can move on.

CHAIRMAN WALLIS: It's worth making every time this comes up.

MR. KELLER: I'll move on to the summary of the Unit 2 results again identifying the changes there. Relatively small pre EPU risk for each of the categories identified.

CHAIRMAN WALLIS: There's also a change in benefit if we're going to talk generalities here which is also proportionate.

MEMBER KRESS: That's true.

CHAIRMAN WALLIS: So the risk/benefit balance is presumably about the same.

MEMBER POWERS: The question is first and foremost is whether we're impacting the adequate protection of the public health and safety.

MEMBER DENNING: That's right.

MEMBER POWERS: And we don't get to count benefit until we've satisfied ourselves on that.

MEMBER KRESS: And that's what these numbers are trying to persuade us.

MEMBER DENNING: No.

CHAIRMAN WALLIS: We would be doing this forever.

MR. KELLER: It's not intended for that purposes. You would use the radiological analysis really as your measuring stick for measuring health and safety for the public.

CHAIRMAN WALLIS: But if there were no benefit.

MEMBER DENNING: We've been through comparisons with the criteria of acceptability. That's where we make our decisions on. They meet the various standards that are established deterministically and that's how we make our decisions.

MEMBER POWERS: Those standards are reliable as 200 calories per gram. Right?

MEMBER DENNING: At least.

MEMBER SIEBER: Even more so.

CHAIRMAN WALLIS: I thought, Dana, you were a great advocate of saying if they meet the regulations then they're safe enough.

MEMBER SIEBER: It's what the law says.

MEMBER POWERS: When did I say that? I must be countering some arguments you were making.

CHAIRMAN WALLIS: I thought you said it was very skillful of the staff to define adequate safety as meeting the regulations.

MEMBER POWERS: Oh yeah.

CHAIRMAN WALLIS: I thought you were sort of endorsing it.

MEMBER POWERS: I think that's an absolute --

CHAIRMAN WALLIS: But you don't necessarily endorse that point of view then.

MEMBER DENNING: I think this is a good time for the conclusions on the PRA.

MR. KELLER: In conclusion, we'll state that all the elements of the PRA model were reviewed for extended power uprate impacts and the increase in risk due to the extended power uprate for Units 1 and 2 is small compared to the current overall threshold.

CHAIRMAN WALLIS: You have increases in frequencies again.

MEMBER DENNING: Thank you.

MEMBER POWERS: What is it in fire PRA that changes the power uprate?

MR. KELLER: What had changed in the --

MEMBER POWERS: Yes, what is it that causes an increase in fire risk?

MR. KELLER: I'll ask Bill Etzel to answer that question.

MR. ETZEL: This is Bill Etzel from First Energy. Just basically we change human error rates and as a consequence of that, any initiating event also increased in frequency.

MEMBER POWERS: So it's just a time they have available to respond before they uncover the core.

MR. ETZEL: That is correct. Right. Or other program measures.

MR. KELLER: Are there any other questions? Okay.

MEMBER POWERS: In the PRAs, the fact that your water is a little hotter and flowing a little faster, there's no way to account for increased corrosion or anything like that in the PRA.

MEMBER SIEBER: No.

MR. KELLER: No, not in the PRA. No sir.

MEMBER POWERS: So the PRA is kind of a void of anything in it that would tell us.

MEMBER SIEBER: That's right.

MEMBER DENNING: Yes, it is very poor. I mean the way we do PRA makes it a very poor tool to evaluate the acceptability of an EPU. Thank you. With that --

MEMBER SIEBER: Would you say that when George is here?

MEMBER POWERS: It -- and the frequencies are done improperly.

MEMBER DENNING: So what else did you want done improperly?

MR. COLBURN: My name is Tom Colburn. I'll be continuing on with the staff's presentation. The staff in the area of reactor systems analysis looked at fuel and nuclear system design changes and determined there were no significant changes to the fuel or the methodologies used in the design analysis. The non LOCA analysis and transients, the LOCA analysis and that was considerations, ECCS boron, precipitation and long term cooling.

The staff review used Matrix A, the Review Standard RS 001. As I said, there were no changes from the NRC's approved codes and methodologies, no changes to the fuel design. No DNBR transition penalties were needed. Uncertainties were applied to initial conditions in a conservative manner and conservative analyses methods and transient assumptions were used and staff determined that all applicable acceptance criteria were met. There were acceptable margins in the safety analysis limits and in the safety analysis results.

Staff review looked at the ECCS systems in their approach to control boron precipitation, large break LOCA analyses, post LOCA long term cooling for boron precipitation, small break LOCA analysis for the short term behavior and post LOCA long term cooling. The staff conducted independent analyses on their own to confirm licensee results and conducted audits at the Westinghouse offices of the licensee analysis and calculations.

MEMBER DENNING: Incidentally, I should comment for both this application and the previous one although the staff didn't do a lot of independent analyses, the staff that made the presentations definitely showed an understanding of these analyses and they clearly looked into them in great detail and clearly understood where the sensitivities were. I thought that they gave very good indication of the understanding. Even though there were some points where there were independent analyses, in general there weren't many independent analyses. But again, for the whole thing they really indicated their understanding of where the insensitivities were in the analyses that were provided to them.

CHAIRMAN WALLIS: Would you tell the Committee what independent analyses were performed because this is just a general statement here? Could you indicate which the more important ones were performed?

MR. COLBURN: I'll defer to Dr. Sam Miranda.

DR. MIRANDA: In the LOCA, there were independent analyses performed extensively in the small break LOCA and in the non LOCA area, we did a sample.

CHAIRMAN WALLIS: Similar of running a code to evaluate the sequence of events and the temperatures and so on.

DR. MIRANDA: Yes, for the small break LOCA, RELAP was used.

CHAIRMAN WALLIS: RELAP?

DR. MIRANDA: Yes. And for the non LOCA analyses, we used LOFTRAN.

CHAIRMAN WALLIS: But you didn't use TRACE.

DR. MIRANDA: No, we didn't.

MEMBER KRESS: It didn't have a deck for this reactor.

CHAIRMAN WALLIS: I thought these decks were transferrable from RELAP to TRACE.

MEMBER SIEBER: No.

MEMBER POWERS: Transferrable is kind of an on/off switch, isn't it? I mean it either is or isn't.

MR. COLBURN: For the non LOCA transients, the staff review followed the guidelines in Review Standard 0001. The events were analyzed with LOFTRAN and VIPRE. Analysis considerations were the power level of 2917.4 megawatts thermal was assumed in the analysis.

CHAIRMAN WALLIS: The staff used?

MR. COLBURN: I'm sorry. The licensee.

CHAIRMAN WALLIS: All right.

MR. COLBURN: The analyses considerations, the licensee used 2917.4 megawatts thermal and that was assumed in the analyses. The actual power level increase is 2900 megawatts thermal.

The Beaver Valley steam generators were replaced in the spring 2006 for fueling outage. The licensee qualified the peak pressurizer safety relief valves water relief during the inadvertent safety check --

CHAIRMAN WALLIS: I think it's 2910 megawatts thermal, isn't it, that they're asking for?

MR. COLBURN: 2910 is the NSSS number. Actual license thermal power level is 2900 megawatts thermal.

CHAIRMAN WALLIS: Where does it say 2910 on their slide six then?

MR. COLBURN: That's the NSSS.

CHAIRMAN WALLIS: I don't understand what you mean by that.

MR. FREDERICK: This is Ken Frederick. The 10 megawatts is the RCP heat input.

CHAIRMAN WALLIS: Oh. Okay. All right. Thank you.

MR. COLBURN: Staff determined that the results satisfied applicable acceptance criteria for peak clad temperature, DNBR and reactor coolant system pressure.

CHAIRMAN WALLIS: Again, this DNBR is something found by the licensee.

MEMBER SIEBER: Yes.

MEMBER POWERS: Plant specific let's say.

CHAIRMAN WALLIS: Okay.

MEMBER SIEBER: That's another way of

saying it.

MEMBER KRESS: Not if it's bigger than 1.24 --

MEMBER DENNING: Go ahead, Chris.

MR. COLBURN: For the large break LOCA analysis, licensee used the BELOCA methodology with COBRA-TRAC. Cold leg break was limiting for boron precipitation. Licensee initiated simultaneous injection before boron precipitation occurs. They increased the minimum accumulated pressure and containment operating pressure which partially offset the increase in power effects for the review and staff determined that they met the 10 CFR 50.46 acceptance criteria for ECCS performance, PCT and cladding oxidation.

For the small break LOCA analysis the licensee modeled their analysis using NOTRUMP. Initially the application assumed even integer break sizes. This was later expanded during the review to include a broader spectrum of break sizes. The initial model assumed a broken loop seal clears for all small break LOCA. Licensee reanalyzed this to assume only that the loops cleared only for certain small break LOCAs in response to the staff's questions.

The licensee increased the accumulated pressure and safety injection flow to gain margin in the analysis and the staff independent calculations agreed with the licensee results. The short term LOCA analysis and small break LOCA analysis and small break and large break long term cooling analogies were determined to meet the 10 CFR 50.46 acceptance criteria.

CHAIRMAN WALLIS: If they identified the need for EOP changes, were the changes that were made satisfactory?

MR. COLBURN: Yes, these were typically changes in operator response time.

CHAIRMAN WALLIS: They also checked that the changes were appropriate and satisfactory.

MR. COLBURN: Yes, the changes for the EOP --

CHAIRMAN WALLIS: Having finding there's a need for something doesn't mean to say you've met that need satisfactorily. So that is okay.

MR. COLBURN: Yes, it is.

CHAIRMAN WALLIS: Probably said that's what they did.

MR. COLBURN: The need for EOP changes resulted in change to operator actions to compensate for the need to perform actions in a more timely fashion. The staff review also confirmed the timing for boron precipitation.

With regard to mechanical impacts for flow induced vibration, the main steam and feedwater piping is instrumented at critical locations. Licensee collected data and evaluated that in accordance with ASME OM-3. A flow induced vibration on the steam separator typically increases at EPU conditions.

(Telephone ringing.)

MR. COLBURN: The flow induced vibration on the steam separators is minimized due to its high stiffness and low flow velocity. Flow induced vibration on U-bend tubing is within the allowable limits. The fluid elastic instability ratio is less than one and the peak stresses are less than the material endurance limit. The potential for fuel induced vibration was determined not to increased for the steam separators and steam generator tubes at EPU conditions.

The flow accelerate corrosion program, the EPU conditions will change the temperature, flow velocity and moisture content for some components. The licensee used an updated CHECWORKS computer model which will help determine future inspection and repair replacement plans. The flow accelerated corrosion program, the scoping criteria, are consistent with industry guidelines for temperature and moisture content, component alloy content and the amount of usage at EPU conditions.

Licensee also looked at the risk evaluation. The full power PRA model was used including internal events, flooding, seismic, internal fires and PDF and LERF. A qualitative approach was used by the licensee for other risks, high winds, external floods and other external events screened per NUREG 1407. Shutdown risk questions in Standard Review Plan Chapter 19 were addressed.

MEMBER DENNING: Let me -- Let's press on. I mean although we don't really think that the risk assessment isn't an important element of this review. As we look at the internal events for Unit 1 for example at 6 X 10^{-6} per year, this is a awfully low internal events core damage frequency. Does the SPAR model indicate that that really is a credible number and the fires at 5 X 10^{-6} per year, those are really small.

MR. LAUR: This is Steve Laur from the Division of Risk Assessment. The SPAR, let's see. I have to find it here on this cheat sheet. Yes, Unit

1 is just under $3E^{-5}$ per year and Unit 2 is a little less under $3E^{-5}$ per year in the SPAR model.

MEMBER DENNING: So the SPAR models are fairly significantly higher than what's being quoted to us.

MR. LAUR: They are the -- They are actually closer to the total risk including fires and seismic that the licensee has.

MEMBER DENNING: Okay.

MEMBER BONACA: Do you have an understanding of the differences, where they are coming from?

MR. LAUR: I do not know. I did reach the benchmark report. We actually, other individuals in the Division of Risk Assessment have gone to every plant to benchmark the significance determination process phase II worksheets and they do that by taking the worksheet, the SPAR model and the licensee's PRA and the conclusion was there's good agreement. That doesn't mean an numerical agreement. Usually what that means is the order of magnitude risk profile and the ability to get a similar result on a significance determination finding.

MEMBER DENNING: You can comment.

MR. ETZEL: Bill Etzel from First Energy.

I believe the major differences in the RCP CL LOCA modeling between the SPAR model and our plant specific PRA.

MEMBER DENNING: And your belief is that your reactor pumps seal model is more realistic.

MR. ETZEL: Yes, we use the Westinghouse WCAP methodology.

MEMBER DENNING: A newer methodology.

MR. ETZEL: And I'd like to comment that they are going to be revising the SPAR model. We just did a PRA model update for Unit 1 and we will be giving that to INEEL so that they can update their SPAR model.

MEMBER DENNING: Have your values always been this low like 6 X 10^{-6}? Those are really low numbers for an older plant.

MEMBER SIEBER: Yes.

MR. LAUR: No.

MEMBER DENNING: No. And what has improved? Have there been changes in the plant design or have there been changes in the methodology?

MR. LAUR: Changes in the methodology primarily. We now take credit for dedicated aug seawater pumps in reducing our RCP seal LOCA. We did a best estimate MAAP runs, ran out to 48 hours with

SBO conditions and found out that we would not uncover the core. Therefore, those small seal LOCAs, 76 gpm and less, as long as we maintain aug seawater we do not uncover the core. So those accident sequences are now going to success state.

MEMBER BONACA: But now it sounds like that SPAR model, I mean the LOCA contribution to CDF from SPAR is very high and that's --

MEMBER DENNING: Fractionally.

MEMBER BONACA: Fractionally. But I didn't hear that from the gentleman behind there that said that there was reasonable agreement between the contributors and the outlier and distributional risks.

MR. LAUR: Yes. What I said was reasonable agreement in terms of core damage frequency profile, in other words, distributed but not the absolute numbers.

MEMBER BONACA: Yes.

MR. LAUR: And in fact, the SPAR models are, they're very good plant to plant because they are standardized and they all use generic data for example. But that's one place that where a licensee can use basically update to use their actual operating experience to get a lower number.

MEMBER DENNING: Again, I think that this is a good application of SPAR regardless of who is right because nobody is really right.

MEMBER BONACA: Yeah.

MEMBER DENNING: But I think that having these kind of base generic models allows you to look and see why is it that they're getting lower values than the NRC is. Again, it's a little bit of a digression here because I don't think it makes a lot of difference to our decision here as to whether it started out at 6×10^{-6} in the internal events or 3×10^{-5}. So thank you and Chris, you can continue.

MR. COLBURN: Staff conducted an onsite audit in October of 2005 to check the quality of the licensee's PRA and EPU risk assessment. The staff's review determined that there were minor impacts on the success criteria, time to recover offsite power, auxiliary feedwater flow for ATWAS as in fact the cavitating venturis, containment accident pressure credit for net positive suction head. There was less time available for some operator actions, post EPU, CDF and LERF MAAP timing.

The staff review validated important short time available actions and performed a human reliability sensitivity analysis. The staff determined that important operator actions that had short term available were depressurizing the reactor coolant system and implementing feed and bleed cooling.

MEMBER BONACA: Did you reach any conclusion regarding quality?

MR. COLBURN: The staff determined that the licensee's analysis and risk assessment were of sufficient quality that we didn't have any concerns.

MEMBER BONACA: Right.

CHAIRMAN WALLIS: Were you not concerned about the short time for initiating feed and bleed?

MR. LAUR: This is Steve Laur, Division of Risk Assessment. The short time for feed and bleed as well as depressurizing the RCS, those are proceduralized operator actions that are frequently trained on by the operating crews in the simulator. They are in response to symptom-based procedures and so it's really more a factor of when you get to that physical step in the procedure because the actual steps you take to perform the action are simple and take between two and ten minutes or ten minutes is probably an outside number. So what we asked the licensee to do is to validate via simulator or a walkthroughs or talkthroughs that the reduced amount of time available did not preclude any operator action.

CHAIRMAN WALLIS: Well, it's now down to 15 minutes or something like that.

MR. LAUR: I believe -- No, I think that was the licensee this morning. I think it was 29.

CHAIRMAN WALLIS: It was the people this morning that was 15 minutes.

MR. LAUR: It was 29 minutes. Help me out here, Bill or somebody.

MR. KELLER: This is Colin Keller from First Energy. Yes, for Unit 1 it was 29 minutes and I believe for Unit 2 it was 42 minutes.

MR. COLBURN: Conclusions with the risk assessment, licensee assessed the potential risk impacts of the EPU. Changes in the core damage frequency were determined to be very small. Changes in large early release frequency were also determined to be very small. The power uprate did not create special circumstances, but the presumption of adequate protection and the risk of the power uprate implementation were actually addressed by the licensee and are considered acceptable by the staff.

In terms of licensee implementation of the power uprate, the licensee indicated that they are going to do a two phase implementation for both units.

Beaver Valley 1 will increase power by three percent for the remainder of this operating cycle and will implement the remainder of EPU next operating cycle. All balance of plant modifications necessary to support the power uprate have been completed, but I think the fuel loading completed during the most recent refueling outage that occurred in April would not allow them to operate for the entire cycle at the uprated power.

Beaver Valley 2 has some more balance of plant modifications to implement. They're going to implement some of those during the fall of 2006 refueling outage and then they're going to increase power by three percent during the following operating cycle. They will implement the balance of plant modifications including the all reaction high pressure turbine modification during the spring 2008 refueling outage and then implement the remainder of the power uprate increase during that following operating cycle.

In summary, the staff review, the licensee proposed a power outage against the criteria that NRC Review Standard RS-001. The licensee supplemented the application numerous times in response to the staff's request for additional information. The review was kept on track in large part by some staff audits that helped expedite the reviews and at the end, the staff determined that the licensee met all applicable review criteria in the review standard for the uprate conditions. What I would like to do -- Are there any questions?

MEMBER DENNING: Any further questions for staff?

MR. COLBURN: What I would like to do now is turn the presentation over to the licensee so that they can provide their concluding remarks.

MR. SENA: Thank you. Again, this is Pete Sena. Again, Beaver Valley would like to thank the Committee for their time and consideration for our uprate application. We believe we have performed detailed and comprehensive reviews. No safety issues had been identified and again, Beaver Valley Power Station will be operated safely and reliably through our modifications, procedure changes, our training and our adherence to our technical specifications and operating license. With that, I would like to open up the floor to any subsequent questions for the Beaver Valley staff.

MEMBER DENNING: I don't think we have any. I would like to thank you very much. Excellent presentations by your staff today and also at the earlier meetings. I'd also like to thank the Regulatory staff for their presentations as well and I think they did a very good job of reviewing this application. So thank you very much.

Now I was wondering, Graham, whether we ought to ask Westinghouse whether from this morning's presentation whether they had an opportunity to determine whether there was any additional information they might present still today.

CHAIRMAN WALLIS: Yes.

MEMBER DENNING: I think they are looking around to see if he's in the men's room.

MEMBER SIEBER: They went back to Pittsburgh to increase the population.

MR. FINLEY: This is Mark Finley from this morning, Ginna's Project Manager. Yes, Westinghouse has some additional information.

MEMBER DENNING: And this looks like a good time, Mark.

MR. FINLEY: If you have time now, that would be good.

MEMBER DENNING: Yes, we do. We have to stay in session here then.

MR. FINLEY: Okay. Good. He'll be in in just a moment.

MEMBER DENNING: So you can stand at your seat and stretch if you would like to.

CHAIRMAN WALLIS: Is this seventh inning stretch or something like that?

(Discussion off microphone.)

MEMBER DENNING: I think we're ready to start here again, guys. Is it easier for you to move a little further that way?

MR. HUGEL: Whatever you want me to do.

MEMBER DENNING: Does that light in your eyes really bother you? Or hadn't you noticed it until I mentioned it?

MR. HUGEL: It really doesn't matter.

MEMBER DENNING: It's okay with you if you want to stay there. That's fine.

MR. HUGEL: As long as I'm not blocking anybody's view.

MEMBER BONACA: No, you're not.

MEMBER DENNING: It's pretty good.

CHAIRMAN WALLIS: I think we're on the record. Does anyone say anything else? We can always come off the record if you want to.

MEMBER DENNING: No, I know we're on the record and we're now back discussing the Ginna Nuclear Power Plant and Westinghouse is going to make a presentation related to the 3-D rod ejection analysis. Please go ahead.

MR. HUGEL: Yes. My name is Dave Hugel. Again, I work for Westinghouse. The question came up regarding the limit that we're using for the rod ejection event. I did contact Pittsburgh and talked to some of our experts and they sent me some slides that I hope will help demonstrate that when you employ a 3-D methodology and we do have this 3-D methodology that was approved. 15806 was the priority version of the methodology, 07 the non PORV in February of '02.

And in this methodology, we transitioned from the 1B analysis methodology that Westinghouse has employed for the last 30 years.

CHAIRMAN WALLIS: Get it clear what the first bullet means.

MR. HUGEL: I'm sorry.

CHAIRMAN WALLIS: You mean the NRC has approved this methodology.

MR. HUGEL: Yes.

CHAIRMAN WALLIS: And now you are licensing it to the plant.

MR. HUGEL: Well, we haven't done that. We have a number of utilities who have contacted us and have requested that we do this analysis for them, but we don't -

CHAIRMAN WALLIS: What does Westinghouse's license mean here? What does it mean?

MR. HUGEL: The methodology, in other words, the approach of analyzing the rod ejection event has been reviewed and approved by the NRC.

CHAIRMAN WALLIS: -- has a license. Okay. I thought you were talking about you licensing something.

MR. HUGEL: No. That would be something new.

CHAIRMAN WALLIS: License it to the licensee. I mean you could let them use it in that sense.

MR. HUGEL: True.

CHAIRMAN WALLIS: So it's ambiguous.

MR. HUGEL: That's true.

CHAIRMAN WALLIS: So you've cleared it up. Thank you.

MR. HUGEL: I'm sorry. Yes, the NRC approved the 3-D rod ejection methodology but we have not implemented it on any of the plants since the industry EPRI, the NRC --

CHAIRMAN WALLIS: But there was no need to do so?

MR. HUGEL: No, because I guess they're still not -- Agreement is still --

CHAIRMAN WALLIS: So it's still 200 calories per gram.

MR. HUGEL: Right. There is no agreement as to what the new limit should be and that's I believe being pursued and they're trying as Paul had mentioned to resolve that and once that is resolved, then I expect that plants will employ this methodology.

CHAIRMAN WALLIS: So maybe we should do something to push this along.

MR. HUGEL: I want to make sure that whatever is decided in terms of a limit is acceptable to everybody and is appropriate for use in the rod ejection event.

CHAIRMAN WALLIS: Well, it's undesirable to have the kind of questions that my colleagues present.

MR. HUGEL: That's true. Good point.

CHAIRMAN WALLIS: And have it not resolved.

MR. HUGEL: Yes. What I'm going to be showing you is just a few slides comparing some of the important parameters for this transient, the 1-D results versus the 3-D method. This plot here is for the zero power case. The zero power case was presented because it results in a prompt neutron condition. You get the biggest rapid increase in power and you see the biggest delta change in your fuel enthalpy and therefore, it's of highest concern in terms of your limit.

MEMBER DENNING: Now this is turned by Doppler. Is that's what's going on here?

MR. HUGEL: That's right. Yes, it's the Doppler you --

CHAIRMAN WALLIS: The message here is that the two methods are about the same over the period of -

MR. HUGEL: And that just shows you that we are still using a conservative approach even though we are using a 3-D methodology. We are using conservative assumptions in this 3-D analysis.

CHAIRMAN WALLIS: Why does this show that you're being conservative?

MR. HUGEL: Because you're getting a very comparable spike in the nuclear power for both the 1-D and the 3-D method.

MEMBER BONACA: What's the difference between the 3-D and 1-D?

MR. HUGEL: I'm sorry.

MEMBER BONACA: What's the difference between the two methods? I mean I would like to understand. You say 1-D. Is it the point kinetics calculation with a peaking factor assigned to it for a thermostatic calculation?

MR. HUGEL: Yes.

MEMBER BONACA: Versus 3-D being what? A neutronic calculation --

MR. HUGEL: Yes. In the 3-D method, we are modeling all three directions. So you're taking credit for your Doppler feedback effects that you would have in a 3-D approach where the 1-D we just estimate what those would be in the radial direction.

MEMBER BONACA: I'm surprised that you're matching the spike.

MR. HUGEL: Okay.

MEMBER BONACA: I would expect the 3-D not to give you that kind of a severe spike.

MR. HUGEL: Okay.

CHAIRMAN WALLIS: 3-D refers to how you're modeling the core.

MR. HUGEL: That's correct.

CHAIRMAN WALLIS: Not how you're modeling the particular piece of fuel that's getting overheating.

MR. HUGEL: That's correct. Here is the Fq. The 1-D as you can see, we don't have the 3-D effect. So it just remains, we go from some initial Fq up to a very high transient Fq and it remains at that transient Fq for the duration of the transient where in the 3-D approach you do see a drop in the Fq due to the increase in the power.

And here is the change in the fuel enthalpy in comparing the 1-D versus the 3-D method and you can see --

CHAIRMAN WALLIS: Why is there such a huge difference?

MR. HUGEL: The huge difference is due to --

CHAIRMAN WALLIS: Same peak. You got the same peak.

MR. HUGEL: Right, and you have the same peak in terms of the nuclear power, but in terms of the effect on the heat, you do get the effect of the 3-D feedback which over the duration of the transient results in a lower total integrated heat that added to the fuel.

CHAIRMAN WALLIS: They cut it off at a different time. So they go up and they level off.

They follow about the same trajectory for the beginning and then when they get to around 40, one of them just gives up and flattens out.

MEMBER DENNING: Go back to the Fq.

MR. HUGEL: Sure.

MEMBER DENNING: Let's go back to the Fq and discuss it.

CHAIRMAN WALLIS: Is it the Fq that does that?

MR. HUGEL: Yes.

CHAIRMAN WALLIS: Okay.

MEMBER BONACA: The confusion here in part is because they switched the colors. In this slide, the red is 1-D.

MR. HUGEL: Sorry.

MEMBER BONACA: And the next slide the red is 3-D.

MR. HUGEL: Oh, you're right. Sorry about that.

MEMBER BONACA: You have a confusion there. All right.

MEMBER DENNING: Back to the Fq and explain to us what Fq is as far as a peaking factor. What is that peaking factor?

MR. HUGEL: In the 1-D method what we do

or what the core designer will do is they'll start with the nominal peaking that you would see just based upon a steady state condition and then what they do is they would look at your rod insertion limits, how far your rod are inserted into the core and then a static calculation is performed where different rods of high worth are ejected and then you look and see what the resulting Fq would be due to the ejection of the high worth rod.

MEMBER BONACA: So you have no benefit for Doppler.

MR. HUGEL: That's right.

MEMBER BONACA: For Doppler feedback.

MEMBER DENNING: I'm not sure that that's it. Isn't really a matter that here you've distorted your flux in the region of where you've ejected it. The neighboring rods get multiplied by a multiplier which is the Fq.

MR. HUGEL: Right.

MEMBER DENNING: Because of the spatial distortion of the flux.

MR. HUGEL: Right.

MEMBER DENNING: We saw the power earlier which is an integral thing.

MR. HUGEL: Right and --

MEMBER DENNING: This is now the local factor times the flux.

MR. HUGEL: That's right.

MEMBER BONACA: But what they do they take the point kinetics calculation and then they multiply by the peaking factor. So in the point kinetics, you get very little Doppler effect resulting from it.

MEMBER DENNING: No, I think you get the Doppler effect.

MR. HUGEL: Yes, you get the same Doppler effect that you see in the nuclear power transient.

MEMBER DENNING: This is just the thermal hydraulic.

MR. HUGEL: Right. This is the thermal effect.

MEMBER BONACA: It's the thermal. Okay.

MEMBER DENNING: And here we see that what it does is that it drops down. There's a very brief period where it's high.

MR. HUGEL: Right. So what you're doing is you're knocking down your total integrated energy that's added to the fuel at the hot spot which is reflected in the resulting fuel enthalpy.

MEMBER BONACA: And probably the integration of the --

MR. HUGEL: Right. Which is integrated power effect at the hot spot and it's primarily driven by what you see in the Fq due to the 3-D feedback effects.

CHAIRMAN WALLIS: This is a typical calculation. This isn't a Beaver Valley or Ginna calculation.

MR. HUGEL: That's correct.

CHAIRMAN WALLIS: So we're near 180 calories per gram that we're talking about.

MR. HUGEL: Correct. But you would expect to see a similar type of benefit if you were to apply the approach --

CHAIRMAN WALLIS: No. I don't know what I would expect. You have to say what you would expect.

MR. HUGEL: Based upon the results that we've done for the full power case, yes, we've seen a similar drop in the peak fuel enthalpy for the full power case. But the full power case I'm told is not of as big a concern because you don't see --

CHAIRMAN WALLIS: This is a license method.

MR. HUGEL: Yes.

CHAIRMAN WALLIS: And are we arguing about

-- Is the criteria going to be changed when you change the method? Is that the other thing? The criterion is going to be changed.

MR. HUGEL: That's my understanding. The 200 is deemed to not be acceptable for this event and if we're going to use a 3-D methodology, then we're going to need to go to some more appropriate limit.

CHAIRMAN WALLIS: Is it going to be very different from 200?

MR. HUGEL: I don't know if Paul can addressed what the latest numbers are or I'm told it's somewhere around 100.

MEMBER BONACA: But the limit is not based on the calculation.

MR. HUGEL: That's correct. The limit is not based upon the calculation. The limit is based upon looking at all the test data and trying to decide what is an appropriate limit based upon the test data taken into consideration that the conditions that the test data were taken under and other factors to make sure --

CHAIRMAN WALLIS: Test data says you ought to come down from 200 to 100 and now developed --

MEMBER POWERS: Let's be very careful.

MR. HUGEL: Yes.

MEMBER POWERS: There's quite a little controversy over how you interpret the data because a substantial body of the data were taken at Japanese reactor with cold water.

MR. HUGEL: Right.

MEMBER POWERS: And consequently, the clad is much more brittle in that cold water case than it would be in a normal reactor case. The really offensive data points were taken in liquid sodium. On the other hand in all of those transients the energy is input to the fuel well before the clad even knows about it.

So there's no cooling effect in there and then you worry about things like how much strain you put on the cladding and that's where the esteemed Dr. Shack and I get into a little cat fight over how you fit data. He's just absolutely dead flat wrong. And EPRI is advancing a point of view on how to analyze that based on the total amount of strain that goes into the cladding and they come up with something around 150 roughly that's fairly insensitive to burn up after you get beyond to 20 to 30 gigawatt days per ton.

The NRC looks at the data and it's a combination of the stand of clad oxidation that's taking place and then amount of burn up that's taking place and they come up with numbers that are like 100 maybe descending down to 80 as you approach to the burn up limit right now. Those are rough numbers. So there is some controversy over it. The one thing that nobody disagrees with is that 178 exceeds everybody's criterion.

CHAIRMAN WALLIS: Doesn't it matter how it being cooled at the time, whether or not?

MEMBER POWERS: Sure. It makes the difference what the temperature is.

CHAIRMAN WALLIS: Right.

MEMBER POWERS: And it makes the difference -- There are lots of things that make a difference. For instance --

CHAIRMAN WALLIS: If it goes to the DNB, then presumably it goes up at a much higher temperature.

MEMBER POWERS: No, none of those things are -- Everything is taking place way too fast for that to affect it. But one of the problems you get into is selecting what is the limiting control rod that does this. If I have a high burn-up fuel assemblies all around a rod assembly, then it doesn't matter. You can take a control rod, throw it away, stomp on it, burn it because there's no power.

CHAIRMAN WALLIS: It's the cooling.

MEMBER POWERS: But if you have very fresh assemblies next to high burn-up assemblies, then you get into a world of trouble.

CHAIRMAN WALLIS: But when the clad heats up, it could heat up by enough --

MEMBER POWERS: Everything is over by then. You've blown the clad apart at this point or not.

CHAIRMAN WALLIS: So all that matters is what's happening inside.

MEMBER POWERS: Yes. Everything is very fast.

CHAIRMAN WALLIS: And it's a rapid expansion of things rather than the heating of the cladding.

MEMBER POWERS: Yes, everything takes place before you really get any heat into the cladding at all. The action is over at that point.

CHAIRMAN WALLIS: You're heating up all the fission products and everything else that's in there and expanding the gases.

VICE CHAIRMAN SHACK: Thermal expansion of the pellet.

MEMBER POWERS: It's really thermal expansion of the pellet that drives it. Now there are lots of other things that occur. In the Japanese tests, they get a prompt release of fission gases on the order of 20 percent of the fuel inventory which is a very big number, four or five times what we ordinarily think of for one of these events whether you've expelled the fuel. That has consequences with things like control room operations and stuff like that.

CHAIRMAN WALLIS: But to go back to the regulations, I understand the present regulations say 200 calories per gram is acceptable using a 1-D method and that's what the licensee has to do is to meet the regulations.

MR. HUGEL: And that's what we've done.

MR. CLIFFORD: The current regulation says 280 calories per gram for a coolability limit.

CHAIRMAN WALLIS: Yes, and that seems extraordinarily high.

MR. CLIFFORD: We know the numbers will be 230 is the correct value at zero burn-up and it's a higher burn-up as you worry about accumulation of fission gas. It will drop.

CHAIRMAN WALLIS: We've had this sort of

presentation from you guys before. I didn't make sense then, the 280, and yet nothing seems to have been done about it. We've been talking about this for several years it seems to me.

MEMBER DENNING: Did you have any more - Is that the end of the information?

MR. HUGEL: Yes, I think that's it.

MEMBER DENNING: Thank you very much. I think it does help us get some feeling as to what the margin relative to the calculations.

CHAIRMAN WALLIS: So we should say then that if Ginna and Beaver Valley had done this this way, that it got numbers somewhat belong 100. Is that your speculation?

MR. HUGEL: Yes.

CHAIRMAN WALLIS: No 45 because this is the high heat.

MEMBER SIEBER: We don't know what these numbers mean.

MR. HUGEL: Right. Yes, we would expect to see numbers under 100 if we were to do it using a similar approach.

MEMBER KRESS: Eighty.

CHAIRMAN WALLIS: But you haven't done it for them. You've haven't specifically done it for them this way.

MR. HUGEL: No, but I do know that I'm told that the analysis that we did here and I hate to use the word "conservative."

MEMBER DENNING: How about "very conservative"?

MEMBER POWERS: Conservative is perfectly okay.

MR. HUGEL: They attempted to use numbers that hopefully will bound what we would expect to see in terms of an ejected rod worth, in terms of the peaking, in terms of the linear heat rate, in terms of etc. because we don't want to present results necessarily that are considered to be generic and then find out when we employ this in a plant specific basis that all of a sudden we get a different result. So I'm told that we selected the numbers to try and ensure that they would bound. Anything would expect to be --

CHAIRMAN WALLIS: This is a so much better method and you've had it for some time, four years or something. I forget the number.

MR. HUGEL: Yes. We submitted it like --

CHAIRMAN WALLIS: Why hasn't it been used and the NRC hasn't found a way to --

MR. HUGEL: Westinghouse and our utilities would love to use it.

CHAIRMAN WALLIS: But you just don't use it because the NRC doesn't know what to do with it when you do use it. Is that right?

MR. HUGEL: I don't want to paint anybody into a corner.

CHAIRMAN WALLIS: Well, it seems to be clear.

MEMBER BONACA: This comparison, this data, from other vendors has been available for 30 years, but they never went to it because they need to spent the money to --

MR. HUGEL: There was no need.

MEMBER BONACA: Because the limit stated 280. So therefore, why spent the money to go to a detail calculation when you do a point kinetics and have -- channel with that one. So you have less Doppler feedback and then multiply peaking factor and get the result and then it's 280.

MR. HUGEL: Actually the running comment at Westinghouse for years was if you analyze rod ejection in 3-D it would go away.

MEMBER BONACA: Yes. In fact, it almost does.

MEMBER POWERS: I think there is some substantial controversy between the staff and Westinghouse on that point.

MR. HUGEL: That was before the French data.

MEMBER POWERS: No, I think it has to do specifically with these analyses and how fast the transient actually is.

MR. HUGEL: Okay.

MEMBER POWERS: Okay. One of the challenges that the experimentalists have had for some time is how to simulate the power impulse and how broad it should be and I believe over the last decade we have come pretty much full cycle from at being a very narrow pulse to a very broad pulse and back to a very narrow pulse. I can't remember all the details, but I believe from now narrow pulse is in. Right?

MR. HUGEL: It's narrower.

MEMBER POWERS: Narrower, yes. Not as narrow as it once was. There's a threshold here that really what matters is whether you get any energy loss to the cladding or not in the course of the pulse and along as your pulse is narrow enough that you don't it could be any narrower.

CHAIRMAN WALLIS: I think we have a little time here. You referred to a published paper which some member of the public was going to read and ask questions about. What were the conclusions of that paper?

MEMBER POWERS: The conclusions of the paper were that when they do experiments on reactivity insertion and the radiated fuel with the high burn-ups, they get failures at relatively low energies, down as low as 36 calories per gram.

MR. HUGEL: But I'm told that the one case that it was at a low was from a liquid sodium reactor and therefore wouldn't necessarily be applicable to a PWR. That it was outlier in terms of the data.

MEMBER POWERS: That's -- The sodiumness doesn't have anything to do with it because there's no power.

MR. HUGEL: It was an outlier in terms of the looking at all the test data.

MEMBER POWERS: What they have concluded and I'll have to admit the details of this often allude me that in the course of preparing the sample they accentuated a flaw in the cladding so that it was more susceptible to rupture than would be ordinarily the case. Now the challenge, the thing that really challenges me on this, of course is not all cladding is pristine. So how much of a flaw does it take? But in general, depending on how you look at it, either 36 calorie or 18 calorie per gram failure rate is generally excluded from the database, but there's a 50 calorie per gram experiment there that doesn't get excluded. So I mean argue 50, 36. I don't care. More important is how you make the change from the fact that you're doing the test at one temperature; whereas you want to do the analyses at a different temperature.

CHAIRMAN WALLIS: It would seem that what we need is the proper experiment or series of experiments.

MEMBER POWERS: The challenge is that a reactor for doing these experiments is a fairly rare device.

CHAIRMAN WALLIS: We're obviously doing experimenting any time there's a rod ejection, aren't we?

MEMBER POWERS: The waiting time, the dwell time, between experiments is long and the instrumentation seems to be generally poor in those events. What they are trying to do is set a hot water loop at CABRI to do some confirmatory experiments but those really are confirmatory experiments. The database exists now. There are challenges in the interpretation, but again, no matter how it gets interpreted 178 is well over anybody's threshold and the challenge that faces this committee is how do we explain to an interested member of the public why you would approve something that manifestly is contradicted by experimental data.

CHAIRMAN WALLIS: There is no change -- There's very little change in terms of the uprate and this 176, 178, or 180 or 182 or whatever it is, there's hardly any change. This is the problem if there was one was there before. It's not the uprate that's caused it. So it would seem that we would have to separate about the uprate and what we say about this issue.

MEMBER DENNING: I think we can let David go now. Is that true?

CHAIRMAN WALLIS: Unless you have anything to say.

MEMBER DENNING: We do appreciate that.

MR. HUGEL: Thank you.

CHAIRMAN WALLIS: Is there anything more that you would like to be able to say? Do you have any more information from Pittsburgh or is this the end? There's nothing more you can say.

MEMBER DENNING: There's not much you can say until you do an analysis that's specifically oriented, has the right rod worth.

MR. HUGEL: Yes, unless we wanted to delve into specific assumptions and stuff which I think is beyond what we're trying to accomplish here.

CHAIRMAN WALLIS: For a different time. Thank you very much.

MEMBER DENNING: That's right.

MR. HUGEL: You're welcome to come to Pittsburgh any time, Dr. Wallis and discuss it.

CHAIRMAN WALLIS: It's too close to --

MEMBER POWERS: We understand the town is getting smaller all the time though.

MEMBER SIEBER: The population.

MEMBER DENNING: Graham, then I'll turn it back to you.

CHAIRMAN WALLIS: Thank you very much.

MEMBER POWERS: There will be lots of hotel rooms there.

CHAIRMAN WALLIS: I'm glad we made use of our extra time. Thank you. We still have some extra time. Is it your wish that we take a half hour break because we can't start? We have draft letters on all the subjects we have to write letters on. So you have plenty of things you could do if you're twiddling your thumbs in the break. We'll take a break until 3:30 p.m. 3:30 p.m. we will meet again. Off the record.

(Whereupon, the foregoing matter went off the record at 1:16 p.m. and went back on the record at 3:02 p.m.)

CHAIRMAN WALLIS: Please come back into session. This is the last formal presentation of the day -- last but not least. And because we may need some guidance on how to respond to it, we have chosen a particularly skillful member of the Committee, Tom Kress, to lead us through it. So, Tom, would you please do so?

MEMBER KRESS: Well, I'm not sure how much skillful guidance I am going to give you. This is the second attempt to update Part 52, Certification Rule. The staff has noted that there was some need for making conforming changes to make it conform better with the usual 10 CFR 50. And to clarify some of the requirements like which parts of 50 apply.

And to just basically improve the rule so that they can implement it more effectively and more efficiently. And they are going to include some lessons learned from the early site permitting process.

I can't go into any detail about what these changes are. There are a lot of them being made. Most of them are procedural. Some of them are not. And simultaneously, I think they are already out for public comment and we are getting a substantial number of those.

This is an interesting subject. I don't know how the staff is going to deal with it in the hour and a half that we have allocated. And so with that as the challenge, I guess I will turn it over to Eileen and let her introduce herself.

MS. McKENNA: Thank you, Dr. Kress. My name is Eileen McKenna. My permanent position is as a Branch Chief in the Financial Policy and Rulemaking Branch of the NRR. But I've recently been asked to take on a special role as a team leader for a group to bring a number of rulemakings that are of particular importance to new reactors to completion over the next several months.

And one of the focal points of that effort is, of course, the Part 52 rule which establishes the framework under which many of these new reactor applications will be submitted and processed.

We're happy to be here to brief you on the status of our activities. And I would like to at this point turn over the meeting to Jerry and Nan who will walk you through the presentation.

MEMBER KRESS: Are you looking for a letter from us Eileen?

MS. McKENNA: We are not requesting a letter. I think, as you will hear through the discussion, we feel that the major aspects of the rule are, as you indicated, to discuss process and procedure.

There are some that deal more in some of the safety requirements and we will focus on those in our briefing but we are not specifically requesting a letter although, of course, the Committee is, of course, free to offer whatever comments they choose.

CHAIRMAN WALLIS: We don't usually interfere in process and procedure unless it has some kind of impact on safety and technical matters.

MEMBER KRESS: Yes, that's why I asked.

CHAIRMAN WALLIS: Thank you.

Well now, are we ready to proceed then?

MS. GILLES: Good afternoon. My name is Nanette Gilles and I am a Senior Project Manager in NRR's Division of New Reactor Licensing. With me is Jerry Wilson, one of the co-authors of the Part 52 proposed rule. Jerry is also a member of NRR's

Division of New Reactor Licensing. The other co-author of the rule is Geary Mizuno from the Office of the General Counsel.

The purpose of today's briefing is to familiarize the Committee with the key objectives of this rulemaking and to provide you with a general overview of the changes to Part 52 as well as other parts of 10 CFR with a focus on the changes that are related to safety requirements.

The Part 52 proposed rule was published in the Federal Register on March 13th of this year. The public comment period ends on May 30th of this year. No comments have been received to date.

This rule supercedes a previously proposed rule that was published on July 3rd, 2003. And the revised proposal results from comments on that 2003 rule as well as lessons learned during reviews of the first three early site permit applications, during the review of the AP1000 design certification, and during numerous meetings with industry on the combined license process.

CHAIRMAN WALLIS: So let's go back. You said that the public comment period has already ended I thought.

MS. GILLES: No, it will end May 30th.

CHAIRMAN WALLIS: Oh, 30th, okay. I'm sorry. I thought you said the 3rd.

MEMBER KRESS: And you haven't had any comments yet?

MS. GILLES: No. We know they are coming, likely on May 30th.

CHAIRMAN WALLIS: Sorry. Thank you.

MS. GILLES: The rewritten Part 52 contains five subparts. Subpart A addresses early site permits. An early site permit is, of course, a license that allows an applicant to bank a site for possible future construction of a reactor or reactors.

MEMBER KRESS: For ten years?

MS. GILLES: Pardon me?

MEMBER KRESS: They bank aside for what -- ten years?

MS. GILLES: Up to 20 years.

MEMBER KRESS: For 20 years.

MS. GILLES: Subpart B addresses standard design certifications which is the process that allows an applicant to attain preapproval of a standard nuclear power plant design through rulemaking.

Subpart C addresses the combined license process. Combined license is a combined construction permit and operating license with conditions. A combined license can reference an early site permit, a design certification, both or neither.

A new subpart, Subpart E is the standard design approvals. This is a subset of the standard design certification process. It essentially does not include the certification rulemaking. A standard design approval represents the staff's review of the design application without the hearing or the Commission review.

MEMBER POWERS: And what goo dis it?

MS. GILLES: Well, the applicant -- if the applicant did not want to wait for the rulemaking process for a design certification, they could reference the design approval and they would at least have finality as far as the staff's review goes. In other words, the staff would not have to re-review that design information. But that would still be subject to the hearing and to review by the Commission.

MR. WILSON: And I would add that we have a long history with design approvals. We have been issuing them since the 70s. And it is probably the most used part of our licensing process. And so we felt it was important to maintain that process.

MEMBER BONACA: What does it mean

standards? I'm sorry. I'm trying to understand the word standard.

MR. WILSON: From the standpoint of we're trying to approve a design that would be referenced many times -- using the same design.

MEMBER BONACA: Okay.

MR. WILSON: So it is standardization from that context.

MEMBER BONACA: So there is still -- yes.

MEMBER KRESS: It is all the staff's review of the certification process without the legal parts of the sign-off.

MEMBER BONACA: Yes.

MEMBER KRESS: It gets that over with and they can just reference it in the certification.

MEMBER POWERS: Yes but there is no proscription against re-raising issues here.

MEMBER KRESS: I wouldn't think so. Not by the staff. The Commission could.

MEMBER POWERS: The Commission can presumably direct the staff to.

(Laughter.)

MEMBER ARMIJO: But apparently it must have some value because people use it. They request it.

PARTICIPANT: I think it is matter of profile.

MR. WILSON: Let me add on to that. Prior to the creation of the design certification that was our design approval process separate from an application so it was frequently used there.

In the future, I think the issue is going to be one of timing and whether a prospective combined license applicant, as Nan said, wanted to wait that additional time for the rulemaking to be completed to achieve that additional finality. Or if they wanted to just reference the design approval in the hopes that they could get through the hearing and get their construction underway sooner.

So different applicants may have a different judgment on that issue. And we want to provide these alternatives.

MEMBER BONACA: But if I understand it, I mean on the rulemaking, okay, pretty much the design is approved in its entirety. And then it cannot be reopened.

MR. WILSON: That is correct.

MEMBER BONACA: And in this case, design approvals -- at least the process in the past was the anybody -- I mean there could be a reopening of the approval.

MEMBER KRESS: Yes, as Dr. Powers was mentioning, subsequent to a design approval, if it is referenced, it could be challenged in the hearing. Or in an appeal, the Commission could reopen something whereas in the design certification process in order to get that additional finality, the rulemaking takes the place of those two things.

And the Commission approves the rule and, therefore, they have, in effect, signed off on it.

MEMBER BONACA: Yes, okay.

MS. GILLES: The fifth subpart in the reviewed Part 52 is the manufacturing license process. This was formerly an appendix in Part 52. This provides a licence to manufacture one or more reactors. The sites for construction of those reactors are not identified in a manufacturing license.

The proposed rule does provide a slight difference from the current rule in that it actually provides greater finality at the manufacturing license issuance stage than is offered in the current rule, very similar to the finality you would get in a design certification in that the final design is approved at issuance of the manufacturing license.

MEMBER KRESS: What goes into deciding? Because you can give a license to somebody to manufacture one of these. What are the criteria?

MR. WILSON: One of the key parts is the approval design and also qualifications of that particular perspective licensee to build -- design and build a nuclear power plant.

MR. WILSON: The standard design holder could also be the manufacturing licensee? Is the licensee -- I think the best way to explain this is to talk about the one manufacturing license we have issued in the past.

There is a company, Offshore Power Systems, which is a subsidiary of Westinghouse. It got a manufacturing license to build floating nuclear power plants that they were going to deploy at various locations.

So their plan was to build that plant at a facility they were planning to build in Jacksonville, Florida, have the whole plant completed and then some perspective licensee who would site it off their coast would purchase it, ship it out to that site.

CHAIRMAN WALLIS: Well, this is interesting to me because we approved something like

AP1000, let's say, but I don't recall that we went into the details of how you are to going to make it and whether you can with adequate controls and so on, whether there are places which are capable of welding large vessels any more with suitable quality control and so on.

So in that scenario, a combined license who references the AP1000 design, they would have to demonstrate that they could do the things that you just talked about.

MS. GILLES: The only appendices that remain in the revised Part 52 are the four certified designs. Appendix A is the General Electric advanced boiling water reactor. Appendix B is the CE System 80 Plus. Appendix C is the Westinghouse AP600. And Appendix D is now the Westinghouse AP1000.

During its revision --

MEMBER KRESS: You get a new appendix each time you get a new design certified?

MS. GILLES: That is correct. That is how it was structured. That that rulemaking, once it was completed, would become an appendix to Part 50.

CHAIRMAN WALLIS: This happens after design certification?

MS. GILLES: Yes.

CHAIRMAN WALLIS: This is sort of a collection of the rules that are applicable to this design then once it has been certified?

MS. GILLES: Yes. During its revision of Part 52, in this proposed rule the staff took two actions that account for the vast majority of the changes in the proposed rule. The first was with regard to Part 52 itself. We standardized the organization and content of each of these five subparts.

The second action was that we made conforming changes throughout the rest of 10 CFR to make sure that all of the other various technical and procedural requirements recognized that the licensing process in Part 52 existed and we tried to be explicit as to which requirements applied to each of these five processes.

Generally in making these changes, we tried to keep the technical requirements where they currently exist in Part 50, Part 100, and the other parts and keep the procedural requirements in Part 52.

And there was a concerted effort on the part of the staff working with the proposed rule not to change those technical requirements that existed in the other parts unless a change was necessitated by virtue of the structure of the Part 52 licensing process being different from the old construction permit operating license process.

There are a couple of main objectives with regard to this proposed rule. First, we feel that the revised rule will enhance our effectiveness and efficiency when we are implementing the Part 52 licensing process in the future. And we also believe that it will provide both the staff and perspective applicants clarity regarding the applicability of these technical and procedural requirements to each of the regulatory processes.

With regard to some of the key rule proposals that effect safety requirements, the first area of focus would be in the emergency planning area. And the majority of these requirements are those issues that fell out of lessons learned during the early site permit process.

First of all, regarding a provision in the early site permit subpart that requires an early site permit applicant to identify physical characteristics unique to the proposed site that could pose a significant impediment to the development of emergency plans, in the proposed rule, the staff has proposed to add a requirement that if such physical characteristics are identified, the applicant also must identify mitigation measures which, when implemented, would mitigate that impediment to the development of emergency plans.

MEMBER KRESS: A couple of questions about that. How does one know what is a significant impediment? Is that a judgment on the applicant? Or is it a judgment on your part? Or do you two negotiate that? Or do you get involved in the emergency plans?

MS. GILLES: Yes. Both at the early site permit stage and the combined license stage there is a review of the emergency plans. Of course the initial decision on what a significant impediment is would have to be made by the applicant. But the staff would certainly, in doing that review of emergency planning, take a look at the site, take a look at the physical characteristics and determine whether they agreed with the applicant's --

MEMBER KRESS: You might identify a significant yourself?

MS. GILLES: Certainly.

MEMBER KRESS: And the change is that -- it has always been in there --

MS. GILLES: Yes.

MEMBER KRESS: -- but now you are saying they have to identify a way to fix the impediment?

MS. GILLES: A way to fix it, correct, because it was sort of left up to the imagination as to what would happen in this situation where a physical impediment was identified.

MEMBER KRESS: And then the ITAAC would insure that when it got to the COL stage that this fix was made?

MS. GILLES: Well, let's be clear here for a minute. There are actually three options with regard to emergency planning under the early site permit. The first option is that you -- and the least work for an applicant -- is that they identify such significant impediments.

There is no ITAAC associated or proposed to be associated with that level of emergency planning review. And I expect that in a situation where an applicant had done that minimum level of -- provided that minimum level of information in their applications and they had identified a significant impediment and proposed mitigation measures, those most likely would show up as a permit condition in the early site permit. That would be my guess as to how it would work.

MEMBER APOSTOLAKIS: Is emergency planning a defense in depth measure that should be established independently of what the reactor is, what the risks are, and so on? Because it seems to me that identifying impediments either by saying you have to be able to evacuate, for example, or it can be done in a different context where you are actually looking at the reactor itself and what the frequency of various releases are. And then you identify possible impediments if there are any in the context of that particular reactor.

So is there flexibility there? Or is it just a defense in depth measure and you have to demonstrate that you are able to handle emergencies independently of what reactor you put there?

MS. GILLES: Remember at the early site permit stage, the applicant is not required to identify the exact design that they plan to build at that site. So our review of emergency planning at that time is independent of the design that will be put there.

MEMBER APOSTOLAKIS: But what if they don't have an ESP. They are free at the COL not to refer to an ESP, right?

MS. GILLES: Correct.

MEMBER APOSTOLAKIS: And at that time, they might come and tell you we are going to put this reactor there which has the following characteristics. Therefore, our emergency planning will be a minimal thing, you know.

MS. GILLES: Yes, at the combined license stage, they only have one option with regard to emergency planning. There is not the requirement to address significant impediments. The requirement at the combined license stage is to provide the complete emergency plan.

MEMBER APOSTOLAKIS: That would depend on the kind of reactor you put there? Or is it independent of that?

MR. WILSON: There is some flexibility on that issue. And I believe the Committee is aware that there is a special provision on emergency planning zones with gas-cooled reactors. But in general, and we're back to the scenario that Nan was talking about in the early site permit, this is a siting decision. And so we are looking at the site and whether it is suitable for a nuclear power plant.

And so the focus of these significant impediments are in siting issues. So an obvious example is you are planning to put a nuclear plant on an island and the question is could other people living on the island get off the island if there was a need for an evacuation.

CHAIRMAN WALLIS: Is this referring to Long Island?

(Laughter.)

MR. WILSON: No, I'm thinking of smaller islands than that.

MEMBER POWERS: I'm struggling to understand why this is a major issue at the ESP stage. By identifying mitigations for significant impediments, certainly none of the ESPs that we looked at had major impediments. And so there was -- it never excited us.

Why did this particular issue come to the fore? I mean we had major problems with emergency planning and ESPs but it was not this. It had more to do with your second bullet which you don't seem to have solved our problem for us.

MR. WILSON: Let's back up a little bit and understand the difficulty that Nan and I have with this presentation. As Dr. Wallis and Dr. Kress were discussing earlier, this is primarily a procedural rule. And in the past, this Committee hasn't been interested in procedural rules.

So we are struggling to pick out some issues here that may have safety significance that the Committee may want to be aware of, and we're not claiming that this is a significant issue but it does touch in that area of safety.

MEMBER POWERS: I want to know why it came up. I mean --

MS. GILLES: I can tell you what I recall is that it came up out of some internal staff discussions about -- as we were preparing for early site permits, about well what would we do if an applicant identified a significant impediment.

And there was more than one opinion about whether the rule would have required the Commission to reject such an application because it didn't state that there was an avenue to go forward with an application that had a significant impediment.

So to avoid that situation, we felt that it was better to clarify that the applicant needed to provide an -

MEMBER POWERS: I can see what it is but I would have thought you would just go through and say look, they are required to outline their major features of their emergency planning, including if you had a major impediment, that would be a major feature.

Now major features, we had real problems with because we ended up with people counting hospital beds, which is ridiculous. That's not a major feature. I mean there we had problems. But I think that had more to do with the review standards than it did with the rule itself.

MS. GILLES: Yes, I would agree. And the second bullet here really addresses the other two options under the early site permit and that is to provide major features or to provide a complete and integrated emergency plan.

MEMBER KRESS: I presume this is aimed at an early site permit that doesn't already have an emergency plan and doesn't already have an existing plant there? Otherwise, they don't have emergency plans.

MS. GILLES: Well, but remember, even though there is an existing site, the early site permit applicant is a separate applicant from the licensee who operates that plant. And it is their choice to use that plan and submit it as the early site permit plan or to go with one of these lesser options. This is not --

MEMBER KRESS: Does he have to project 20 years into the future for these significant impediments?

MEMBER POWERS: Sure. Yes, you have to. When you come to the ACRS you will be asked that question.

(Laughter.)

MEMBER POWERS: But I suspect that the major -- the major impediment I can imagine for an existing site was a change in the political administration of the region.

MEMBER KRESS: Wow. How am I going to predict that?

MEMBER POWERS: Well, you are not required to predict accurately. Responsibly but not accurately.

MR. WILSON: Well, for the benefit of the audience, I'd like to clarify that point. Major impediments are physical features that we are looking at.

MS. GILLES: With regard to the second bullet, as you mentioned there were quite some fairly large struggles with how to deal with major features at the early site permit stage. And so we've actually undertaken a couple of actions in the proposed rule.

One is we have posed a specific question to ask whether the Commission should try to further define what a major feature is and provide some higher level of finality associated with the major feature to make it more useful to a perspective COL applicant. And along with that, that increased finality with major features we have required that. An ESP applicant that submits a complete plan or major features of a plan, that they include the inspections, tests, and analysis, and acceptance criteria that would be needed at the combined license stage to finalize those plans.

So that will allow the staff to make the same reasonable assurance finding at the early site permit stage that it could make for a combined license applicant that had ITAAC with --

MEMBER POWERS: I really struggle with this. I mean it seems to me that the emergency planning aspects that we just ran into all -- every time we went to anything beyond the most high-level statements on the emergency plan we ran into -- and we can't do anything right now so we will have to move back to the COL stage.

And there always seemed to be good reasons for saying we can't do anything about that. I mean it seems to me that enhancing it at the early stage, that is not what I would have expected you to do. I would have expected you to downgrade what is in the existing rule. Or make it very clear what you were looking for rather than asking for more detail. Nobody can do it.

MS. GILLES: Well, the industry has expressed interest in having flexibility regarding emergency planning at the early site permit stage.

MEMBER POWERS: Yes, they want flexibility. They don't want to get locked into anything.

MS. GILLES: Well, I will point out that we have reached agreement with the industry on a set of emergency planning ITAAC that have been sent to and approved by the Commission. So we actually have made fairly good progress with regard to ITAAC in the emergency planning area.

MEMBER POWERS: I don't think anybody wants to do those at the ESP stage. I mean I think they will just -- everything will just get -- it will just be a condition in the ESP. I mean you are kind of wasting your time here.

MS. GILLES: I think time will tell whether that is true. We have heard applicants say they are interested in pursuing this option although we have yet to see that.

MEMBER POWERS: Yes. I mean I can only

speak from experience that all these things, they just kind of throw up their hands and say there is nothing I can do right now because I don't have a plant, I don't know when I'm going to do anything, I don't know what the future is going to really look like. And I don't know how many hospital beds I need.

And so we just -- I mean we did have people counting hospital beds and doing a lot of things that they felt was useless. That they were just simply going to have to redo it again.

Now maybe the next ESP will come in and say he wants to lay out his emergency plan out to six significant digits. But I'm not betting on it.

MS. GILLES: We will find out fairly soon here.

Another requirement related to emergency preparedness that appeared both in this proposed rule on the previous 2003 proposed rule was the requirement that combined license applicants that referenced an early site permit update and correct the emergency preparedness information that was provided in the early site permit.

This was actually suggested as an alternative to a proposal by one of the states several years back that applicants be required to update the information throughout the life of their early site permit. And the industry proposed this as an alternative: that they have a one-time update requirement at the time that application is referenced in a combined license application.

In addition to identifying this new information, the applicant must discuss whether the information would materially change the basis for compliance with any NRC requirements so that the Commission can determine that it needs to modify the permit based on this updated information.

MEMBER MAYNARD: Could you clarify for me what you are talking about with emergency preparedness information? Are you talking about population or bridges or what is in the area?

MS. GILLES: Well, it could be any information that was provided at the early site permit stage. And remember we just discussed the applicant basically has three choices as to what level of information they can supply at that stage.

MEMBER MAYNARD: Okay.

MS. GILLES: So it could be anything -- related to anything that was supplied at the early site permit stage.

MEMBER POWERS: If we are in, for

instance, one of the concerns is that military bases either get installed or de-installed at a facility which -- I mean de-installing it can effect your fire protection planning. Installing it can effect all kinds of things. But I think that effectively is in the rules anyway. I think it is in Part 50.

MS. GILLES: Another area where some of the technical requirements were changed in this revised proposed rule relates to quality assurance requirements for early site permit applicants. We placed a explicit requirement in this rule that the Appendix B quality assurance requirements apply to early site permit applicants.

MEMBER KRESS: Can they really do that? Suppose you have an ESP applicant who doesn't even reference a certified design or any kind of plant, can he do this QA requirement?

MS. GILLES: Well, we believe they can do it and remember we are talking about them applying the QA requirements as they would apply to the siting activities that are going on during their application and the review of this application for the early site permits.

MEMBER POWERS: You've got a huge amount of stuff coming in as far as well-testing data, drilling, things like that.

MEMBER KRESS: Oh, that's the QA requirement you are referring to?

MS. GILLES: Yes.

MEMBER KRESS: You are not talking about SSCs?

MS. GILLES: No.

MEMBER POWERS: I mean there is a huge body of data that supports these things. And I don't think this -- the QA requirement, I don't think they pose an unusual burden. I mean I think people in the nuclear industry are relatively used to handling data in that kind of fashion.

MS. GILLES: Another area in the technical requirements where we have made some changes in this proposed rule relates to the applicability of 10 CFR Part 21 and the related requirements in 10 CFR 5055(v) to entities that hold a permit or a license under 10 CFR Part 52.

These changes would address an omission in the existing regulations and ensure that requirements in Part 21 and 5055(E) apply to applicants for and holders of early site permits, design approvals, design certifications, combined licenses and manufacturing licenses and suppliers of basic components to such applicants and holders.

The proposal is based on the thought that the extension of NRC's reporting requirements that implement Section 206 of the Energy Reorganization Act should be consistent with three key principles.

The first principle is that NRC regulatory requirements implementing Section 206 should be a legal obligation throughout the regulatory life of an NRC license approval or certification.

The second principle is that defects should be reported whenever the information on potential defects will be most effective in ensuring the integrity and adequacy of the NRC's regulatory activities under Part 50 and the activities of entities subject to the Part 52 regulatory regime.

The third principle is that each entity conducting activities within the scope of Part 52 should develop and implement procedures and practices to ensure it accurately and timely fulfills its Section 206 reporting obligations.

The applications of these three principles to each of the five subparts of Part 52 is described in detail in the Federal Register notice that transmits the proposed rule. This is one of the areas that the staff found that there were really some extensive conforming changes needed in another regulation to make sure that it addressed all of the Part 52 licensing and regulatory processes.

The final area I will discuss regarding an area that relates to some of the technical requirements is in the area of PRA. There is an existing requirement in Part 52 for design certification and combined license applicants to submit a probabilistic risk assessment with their application.

However, in the staff requirements memorandum that the Commission sent the staff after it had reviewed the rule, the Commission asked the staff to pose a specific question and request comments on that question regarding the need for a living PRA requirement.

The staff asked whether the Commission should adopt in the final rule a new provision that would require combined license holders to update the PRA, submit it with the combined license application periodically throughout the life of the facility on a schedule either similar to that for the FSAR updates or perhaps with every other refueling outage.

The Commission has asked for stakeholder feedback on whether such a requirement should be added in the final rule. And if so, what update periodicity should be associated with that requirement?

MEMBER KRESS: So what did you decide to put in the rule?

MS. GILLES: We haven't decided yet because we are still in the public comment period.

MEMBER KRESS: You are waiting for that.

MS. GILLES: Yes. We will have a specific section that addresses this question and the comments we received in answer to this question. And then the staff's and the Commission's decision with how to go in the final rule regarding this issue.

MEMBER APOSTOLAKIS: Is the issue only one of having a living PRA? Or also what kind of a PRA?

MS. GILLES: In the rule that the staff sent to the Commission, there was some attempt to address what kind of PRA should be in the rule. And the Commission directed the staff to take that language out of the rule and to address those issues in the regulatory guidance associated with Part 52.

So to my knowledge, there will be no rule language that addresses the type of PRA. That will be contained in regulatory guidance.

MEMBER POWERS: The question of periodicity of updating anything, it is difficult to come up with.

MS. GILLES: It is but we do have some model to follow with the FSAR update procedure which is why we linked the question to that.

MEMBER POWERS: I know and it has been a frustration. I mean that has not been a bed of roses itself.

MS. GILLES: I will be the first to agree with you that there are difficult issues to tackle in this rulemaking.

MEMBER POWERS: I don't know how you come up with it.

MEMBER APOSTOLAKIS: What would be the purpose anyway? Let's say you are asking them to do it every two years. Then what? I mean are they going to give it to you or -- okay, they update it. Now what? I mean there is no requirement for them to use it.

MS. GILLES: No, the idea -- I'll tell you what we stated in the question is that the PRA update submittal would be required to contain all changes to reflect information and analysis submitted to the Commission by the licensee or prepared by the licensee pursuant to a Commission requirement since the submittal of the original PRA, or since the last update. It's really, in my mind, the way the question was posed. It is simply a way for the staff to have an updated version of the PRA for every plant.

MEMBER APOSTOLAKIS: For what purpose?

MEMBER KRESS: Does that make the PRA part of the licensing basis then?

MR. WILSON: I don't think so. And we tried to clarify that point to a certain extent in this proposed rule where we pointed out that PRA is part of the application but not part of the FSAR. But back to Dr. Apostolakis's question in terms of how you would use it, we have a couple of members of the PRA branch in the audience. And I looking out there to see if one of them would want to offer some views on that point.

MEMBER POWERS: For one thing, the staff is always in the position to ask for the risk of any change -- associated with any change that the applicant wants to make. I mean you can always do that as part of the license amendment process. And so presumably you would want that to reasonably reflect any changes that have occurred in the plant.

And in some respects, it may happen whether there is a rule or not. But I assume that you would want some assurance that the PRA was up-to-date that was used there.

MEMBER APOSTOLAKIS: It seems to me though that the most important issue is what kind, what scope the PRA would have rather than how frequently you update it.

MEMBER POWERS: Well, I agree with that but, you know, we haven't figured out how to enforce what scope yet.

MEMBER APOSTOLAKIS: Because my understanding is that people more or less agree that you have to have a good internal event up power PRA. Now I hear that we've sort of agreed to have a good fire PRA. But other than that, I'm not so sure. I mean shutdown is still up in the air. Other external events, losing some bounding techniques and all that.

I mean I don't know how -- why not do a shutdown PRA, too? I don't understand that.

So you will issue regulatory guides that will have this kind of information? I mean I don't understand how that would work.

MEMBER KRESS: Who is going to speak? Go ahead and use the mike.

MR. TESTA: Mike Testa, Division of Risk Assessment Deputy Director. I think the intent of the requiring the PRA updates was as we evolve in the use of risk, it is becoming more and more a part of day-to-day operations with the maintenance rule, with the ROP. And the requirement to submit a periodic update of the PRA would be nothing more than insurance to the staff that the licensee was maintaining it in a state that could be used for those types of applications.

So where now there is no specific requirement to update, you know, the NRC does have some type of expectation that were the PRA to remain a viable tool to use for these applications that it is updated.

So I think it is basically a more explicit statement of what expectations are for the way people operate right now.

MEMBER APOSTOLAKIS: My understanding is that the regulatory guide cannot impose any requirements. No matter what you say in the guide --

MR. TESTA. Right. I thin we are talking on different issues. I mean I was talking about the requirement to submit a periodic update.

I think the Commission was -- it was my interpretation of a message they were sending back to the staff is that, you know, we are a little bit in the state of flux with what we were going to require for a PRA because if there aren't standards in place, you know it makes it a little bit more difficult to say for a licensee that you need to have all these different all modes, internal/external event, PRA out there for use but the standards yet haven't been developed yet. And haven't been concurred on by the NRC.

So I think the message to the staff was figure out at the time how to work your way through that issue. And that is better fitted in a regulatory guide rather than regulation.

MEMBER APOSTOLAKIS: Still, though, in a regulatory guide, you cannot require anything.

MEMBER KRESS: But you can require an update.

MEMBER APOSTOLAKIS: A what?

MEMBER KRESS: You can require an update in the rule.

MR. WILSON: Could I clarify this point?

MEMBER APOSTOLAKIS: Oh, another two, three year process just to change that. I thought the whole idea was not to revise the rules --

MEMBER MAYNARD: But typically with a reg guide, the licensees either expect it to commit to it or show how they are -- what method they are using to accomplish the same thing. The reg guide doesn't impose a specific requirement on you but the licensee either got to commit to it or to demonstrate how they are going to meet the same objections.

MR. WILSON: Let me clarify this. They have a requirement to submit a PRA. We are talking about adding a requirement to update that PRA. The issue of the reg guide is how do you meet that requirement to submit a PRA? In the reg guide is going to be guidance on what type of PRA You have to submit. But these is a requirement to submit one as part of your combined licensed application and you application for design approvals.

MEMBER APOSTOLAKIS: Well, the thing that comes to my mind is at the last meeting, we reviewed the regulatory guide, attempting to risk inform the fire -- an FBA 805 implementation. And we were struggling with the issue of talking about the PRA when the rule does not require it.

We were told very explicitly that you cannot say that the PRA is needed because the rule doesn't say that you need it. So we have to dance around it.

MR. WILSON: I understand. But remember --

MEMBER APOSTOLAKIS: I don't understand

why we have to create these issues.

MR. WILSON: In the scenario you are talking about, you are talking about operating plants. There is no requirement for operating plants to submit a PRA. The requirement we are talking about is the requirement for future combined license applications or for design certification applications. That requirement has been on the books since 1989.

And the reg guide would just be what type of PRA do you need to submit to meet that requirement. So we wouldn't have the problem you are talking about with the operating plants.

MEMBER APOSTOLAKIS: Well, I don't remember exactly how 50.40 something --

MR. WILSON: 50.48.

MEMBER APOSTOLAKIS: Forty-eight.

CHAIRMAN WALLIS: Can I go back to what our role is in this whole process here? Eileen, you indicated that maybe we didn't need to write you a letter. But then do you want us to -- there are various things we might do. I mean you might just look at the transcript and say they said various things. That's all we need at this stage.

But do you expect us to have some interactions with you again before the final rule?

MS. McKENNA: Well, let me give you the schedule of what we are on so you kind of have an appreciation of the picture. As was indicated, the comment period ends the end of May. The SRM that the Commission sent us on the proposed rule said that they wanted the rule back to them in October of this year.

There is not a whole lot of time between the end of May and October for us to turn around a final rule and have additional interactions with the Committee. We really would like to have a sense from now as to whether You would like to hear more or You feel that You don't need to hear more?

CHAIRMAN WALLIS: Well, in terms of that, we have no major issues with what You are doing. Do You still expect to come back to us sometime between now and October?

MS. McKENNA: I don't think we envisioned there is time between now and October to come back.

CHAIRMAN WALLIS: So this is our chance to say something --

MS. McKENNA: This would be your chance, yes.

CHAIRMAN WALLIS: -- if we wish to do it?

MS. McKENNA: This would be your chance, yes. Yes.

CHAIRMAN WALLIS: And if we don't wish to say much or anything, then we never say anything again. Is that your view?

MS. McKENNA: Well, we would hope that would be the case. I mean normally when we go to the Commission, we include in the rule package, we include a paragraph that describes what level of coordination we have had.

CHAIRMAN WALLIS: You might want to let us --

MS. McKENNA: Or a memo that says we've had this meeting.

CHAIRMAN WALLIS: You seem to be on the right track and that's it.

MS. GILLES: You know then maybe you don't --

CHAIRMAN WALLIS: I mean if we are silent, does that just give consent?

MS. McKENNA: Well, is you are silent, then the approach we would most likely take is when we go to the Commission with our final rule package in October, we would include a sentence in the coordination section that says we met with the Committee on thus and so date. And the Committee did not choose to send any comments.

CHAIRMAN WALLIS: We could say we see no major problems with what you are doing. And we don't really see how we would add value by, you know --

MEMBER APOSTOLAKIS: Or we say nothing.

CHAIRMAN WALLIS: Or we say nothing at all. But that sort of leaves it equivocal doesn't it? If we say nothing at all?

MEMBER APOSTOLAKIS: No, it means we don't object.

CHAIRMAN WALLIS: No, I don't think we should say -- yes, we could do that. We would say if we can't add value at this stage, we will just say nothing.

MEMBER DENNING: I mean can't we take an intermediate position in terms of -- I mean say nothing at this point but make it clear that we want the ACRS staff to take a look at it? See right now what we are seeing is all of the things that we would be interested in would be in the regulatory guides. As, you know, they are pointing out, this is just kind of structure.

CHAIRMAN WALLIS: Right.

MEMBER DENNING: You know the things that we are really interested in are still to come. There are going to be regulatory guides. But you don't know until after that. You know so can't the staff review it at some point and then say yes, the Commission -- I'm sorry -- the ACRS wants to hear it? Wants to talk with you about it?

MEMBER APOSTOLAKIS: Before the rule is issued you mean? Before when?

MEMBER DENNING: Yes, before the rule is issued. After they have drafted it, don't we get a -- I mean it seems to me we send a lot of Larkins-grams that say yes, we want to look at it. Or no, we don't. I mean can't we be in that position there where the staff takes a look at it and says there is nothing in here that the ACRS is really going to be -- I mean our staff -- can't we do that?

CHAIRMAN WALLIS: Or we may have reached that decision already.

MEMBER DENNING: Well, we may but we don't know yet.

CHAIRMAN WALLIS: All right.

MEMBER DENNING: I mean that is the --

MEMBER APOSTOLAKIS: What you want to prevent is us coming back in four months with a whole lot of criticisms.

MS. McKENNA: Absolutely because we would not bel able to deal with it at that point in time.

I think the point, too, is that if your issues are in the reg guide, then that is something we can handle in a different manner because what we need to send up to the Commission and the rule and the resolution of comments and some recognition of at least non-objection by the Committee to proceeding with the rule.

VICE CHAIRMAN SHACK: One substantive issue is the update.

MEMBER KRESS: Yes, that would one we would want a copy of I think.

VICE CHAIRMAN SHACK: Yes, that seems to be something we certainly might want to comment on.

MEMBER APOSTOLAKIS: And we don't know whether the public comments will address any of the --

MEMBER DENNING: Well, they are looking for stakeholder input. We are stakeholders.

CHAIRMAN WALLIS: Are we?

MEMBER KRESS: Yes.

CHAIRMAN WALLIS: Lab material. We are advisors. We don't have any stakes at all.

MEMBER DENNING: I would certainly like to see what NEI thinks about these things?

MR. FREDERICK: Yes, it would be nice to know.

MEMBER SIEBER: And another meeting is going to add a month to the schedule.

CHAIRMAN WALLIS: Do we want to have another look at this thing?

VICE CHAIRMAN SHACK: Graham, we are going to have the opportunity to hear from NEI during this presentation sometime.

CHAIRMAN WALLIS: Are we going to hear from NEI again -- on this thing again?

VICE CHAIRMAN SHACK: Well, they are here today to get our comments.

CHAIRMAN WALLIS: Okay, okay. I see.

VICE CHAIRMAN SHACK: Maybe we ought to hear it.

CHAIRMAN WALLIS: Let's hear from NEI. Has the staff finished its presentation?

MEMBER KRESS: I'm not sure.

MS. GILLES: Yes, that concludes our presentation.

MS. McKENNA: I might just remind the Committee that what was in the Commission's SRM on this particular rule, in fact they spoke specifically about the Committee. I don't know if you are aware of this.

What they said is in the manner that

supports the schedule, the staff should seek advisory Committee on reactor safety on feedback on technical issues, if any, during the public comment period. And that is exactly what we are doing.

CHAIRMAN WALLIS: I remember that. I remember that. Right.

MS. McKENNA: During the public comment period. And that is exactly what were doing it. During the public comment period is the worst.

CHAIRMAN WALLIS: They sat on technical issues.

MS. McKENNA: On technical issues, that is correct. That is our purpose here today.

CHAIRMAN WALLIS: So should we hear from NEI? Is that the plan?

MS. McKENNA: Yes.

CHAIRMAN WALLIS: Let's do that.

MEMBER KRESS: You have an NEI presentation?

CHAIRMAN WALLIS: Ralph is going to stay around so that we come back to it whenever we ants to. Thank you.

Now we also don't have the role of referee between NEI and the NRC. No, and that is not our job if there are issues like that.

MEMBER KRESS: But we are welcome to speak out on those issues.

MR. BELL: Some of you know me. I'm Russell. I'm with the Nuclear Energy Institute. And it is a pleasure to be back with the Committee.

We were shocked at the extensiveness of this rulemaking when we first saw it last fall. It was coming at a time when it had been delayed several times and at the same time, progress towards COL applications was being accelerated.

So we were faced with the situation of dealing with the extensive rulemaking at the same time moving forward with applications, moving forward with COL application guidelines, and what we would have preferred and what we recommended to the Commission in a briefing and in a letter in December is a skinnied-down rulemaking that focused just on the necessary changes, the beneficial changes. And the clear lessons learned from the interactions we have had to date on design certification and NESP.

Ultimately, a majority of the Commission decided to proceed with the rulemaking so here we are. And I can tell you it is difficult to do justice to the rulemaking while applicants are focusing on writing their applications and getting them done by the end of next year. But we are trying to stay focused on that and do our jobs and respond to the rulemaking.

To be sure, there are a number of good things in the rule. Unfortunately they were overwhelmed by the magnitude of things we either didn't understand or didn't agree with or didn't think were necessary. But there are some conforming changes to NRC regulations like 50.59 which was completed in 1999 so it wasn't reflected in the earlier certifications.

Conforming changes in the Energy Policy Act, terminology clarification, consistent use of terminology, these are all good things. The notion of completing ITAAC early if you can at the COL application and review phase rather than just prior to operation, just prior to fuel-up. That is a good idea. And that is in the proposal.

But there was a great deal more that concerned us, particularly the extensive cross references to Part 50 that were inserted in Part 52. It made it very hard to tell what was going on and to be sure about what is going on. And to be sure we fully understand it.

And again, it created an air of

uncertainty at a time when applicants were trying to move forward based on the rules they had come to know and love.

As I said, the Commission directed the staff to proceed almost as they had proposed. We were glad to see that they had redirected the staff on the scope of the PRA and they had the language taken out that you were just discussing, the full scope, all modes language. So that's not in there.

I think it is a question for another day what that scope is. But it is more appropriate to deal with that in guidance land and not rule land. And we will be discussing that with the staff, I would guess, in the next couple of months, again in the context of the COL applications guidelines that the staff is preparing.

That was the single -- if you had to isolate the single biggest concern about the staff proposal, that was it. And we were glad to see that addressed.

So we are now addressing the rule that was published on March 13th. Comments are due -- oh, my word --

MEMBER APOSTOLAKIS: Excuse me, Russell, when you say there are some licensees that are already writing COLs.

MR. BELL: Yes.

MEMBER APOSTOLAKIS: What kind of guidance are they following? Is there any guidance right now for that?

MR. BELL: No. There is draft guidance that NEI prepared. There is much we know and much we understand about the process. And the company are proceeding on that basis.

MEMBER APOSTOLAKIS: So these regulatory guides that we were discussing with the staff, when will they come out?

MR. BELL: I won't speak for the staff but -- do you want to go, Bill?

MR. BECKNER: This is Bill Beckner. I'm Deputy Director of the Division of New Reactor Licensing. We have a commitment to put out a draft in June of this year.

MEMBER APOSTOLAKIS: Of this?

MR. BECKNER: Of the content, yes.

CHAIRMAN WALLIS: Could you clarify something you said? I think you said that this requirement for a full scope, the staff had backed off from that? Is that true?

MEMBER APOSTOLAKIS: No, they were

directed to back off.

CHAIRMAN WALLIS: They were directed to? So they have backed off from that? Okay.

MR. BELL: Wait a second. Let's make sure we understand. It is not in the rule. It is not going to be in the rule. But it could very well be in the regulatory guide.

CHAIRMAN WALLIS: It could be in the guide, yes.

MEMBER APOSTOLAKIS: Yes, but they were directed to take it out.

CHAIRMAN WALLIS: Because it is not in the rule, okay.

MEMBER APOSTOLAKIS: The language.

MR. BELL: We would have the same concern if it appeared in a guideline. Of course somebody mentioned earlier a guideline is not a requirement. Nonetheless, it is not good guidance to ask for something that no one knows how to do and that there are not standards to provide. So that is the point we would make.

CHAIRMAN WALLIS: That's like saying we want to go to the moon.

MEMBER KRESS: How do you feel about the potential requirements for periodic updates of the PRA that you have?

MR. BELL: Folks are doing that now.

MEMBER KRESS: It is not a big imposition is it?

MR. BELL: We are going to do it in the future consistent with the standards. I don't think that is the issue. I think it is an issue whether that needs to be submitted to the staff either initially or every cycle or every other cycle.

I share some of the questions that the Committee was raising. I don't know what the staff will do with that. And, again, it is not consistent with what has been determined to be appropriate for today's --

MEMBER POWERS: Wouldn't you anticipate that what they really want is okay, if risk issues come to the fore, new licensees should have available at your site for me to inspect a PRA that is reasonably up-to-date with respect to your plant rather than submit it because the staff doesn't have the manpower to review the PRAs that it has now let alone new ones coming in.

But a requirement that says look, if you are going to use risk or invoke risk somehow, I need to come and look at the details of what you have got there.

MR. BELL: I would see no problem. We are going to maintain those things on site. The staff can come at any interval or frankly any time they choose to come see the latest update, examine your process for your update. And again, there are standards for that.

So I believe that would be the nature of our response to the question that is in the notice of proposed rulemaking. And whether that translates -- I haven't thought this through -- I'm not familiar with our draft preliminary comment on this -- whether that translates to a rule requirement of some sort to have it maintained, I'm not sure. But certainly the periodic submittal, I don't think it is something that we would comment against.

MEMBER POWERS: This requirement, what do you do with them? It's a big pile of papers that nobody is going to look at.

MR. BELL: And is it paper or is it the decks and codes? So there is a question in my mind what do you mean when you say submit the PRA? I think --

CHAIRMAN WALLIS: Well since the time isn't the issue, the issue is that when you need to make a decision based on risk, you should have an effectively up-to-date PRA. And if nothing has changed, maybe you don't need to update it. But as soon as something significant changes which will effect the PRA, You really ought to incorporate it into it.

MR. BELL: In fact, that's -- as I understand the current standard, that is exactly what the plants are doing. At a periodicity, they assess the need to update. And if things have changed to a certain degree, the update is made.

MEMBER KRESS: How do you view the requirement of radiological consequence analysis?

MR. BELL: I don't like ti.

MEMBER KRESS: At the ESP stage?

MR. BELL: Yes, I was going to mention that one. We saw this in 2003. We see it again in 2006. And I think it points up that sometimes we and the staff perhaps took away different lessons learned. We talk about a lessons learned rulemaking.

The lesson we learned on this one is that it makes no sense for an ESP applicant who doesn't know yet what he wants to build to try and provide detailed radiological consequence analyses, which requires a great deal of design information, source term, mitigation systems, and so forth.

They only have to be -- they will have to be repeated again at the COL stage using the design-specific information. So we will be making a different proposal in our comments on that area.

It's not unlike -- I was just reminded, the emergency planning information. The decision was made, and I think appropriately, it makes no sense for an ESP applicant to update that periodically. What if nobody ever references the ESP?

The same kind of thing -- there is no need at the ESP stage to do something that has to be -- only comes into play at the COL.

MEMBER KRESS: Could you also comment on -- there was a provisions for being able to go ahead and operate the plant at a level of about five percent power even though there might have been impediments to the emergency plan brought forth by FEMA? Could you comment on whether that is advisable or not? Or how you feel about it?

MR. BELL: As I understand it, that was an agreement that we and FEMA and NRC arrived at together. And it is based on current practice near as I can tell. And Bruce is back there and can correct me.

If there is a FEMA issue, so that is a problem -- some sort of open item on the off site portion of the emergency plan, I think the theory is that there is -- the company could proceed up to five percent power while addressing that concern.

MEMBER KRESS: Yes.

MR. BELL: And that that is just a practical issue and not -- for the company to be able to efficiently deal with that and that there is not a safety issue or an emergency planning concern because of the low power issue.

MEMBER MAYNARD: Thank you. Typically there is about a four- to six-month period at low power for a lot of testing on a brand new plant.

MEMBER KRESS: Which is plenty of time to fix the problem.

MR. BELL: To resolve those kinds of things. I think we have also agreed that anything -- any problems identified with the on site plan would have to be addressed prior to fuel load. So we are just talking about the off site piece. And I believe there is consensus on that point.

I'd highlight a couple other things while you are thinking of other questions for me. We've got comments large and small on the package. Of course, it is over 650 pages.

MEMBER KRESS: Yes, we noticed.

MR. BELL: I'm trying to make sure that our comments come in at fewer than that. But I'm not making any promises. We are concerned about the reporting requirements under Part 21 being extended to ESP applicants, and design certification applicants, and ESP holders.

MEMBER KRESS: That's the QA?

MR. BELL: This is reporting defects to the NRC --

MEMBER KRESS: Oh, yes.

MR. BELL: -- under Part 21. I think there is a change that is needed to Part 21. I don't think it is the change that the NRC staff has proposed.

There can be no reportable situation under Part 21 if the ESP hasn't been referenced by a COL applicant or if a design certification hasn't been referenced. So I think the change that is needed needs to reflect that nuance. And so we are working on that one.

The new requirement for applicants to address international operating experience, we are not sure how that --

MEMBER APOSTOLAKIS: In general or --

MR. BELL: -- would be done.

MEMBER APOSTOLAKIS: -- from limited -- I mean what does that mean?

MR. BELL: Well, exactly to what extent, how do we become aware of that. I mean generally the NRC is a player in other, you know, agencies worldwide and is a source of that information. There is WANO and, of course, INPO's participation in that. But it is not clear to us that that is an appropriate requirement or a necessary one.

I'm not sure there is a problem here.

CHAIRMAN WALLIS: It might be appropriate and some of these reactors might well be first built in other countries.

MEMBER APOSTOLAKIS: Yes, but my question is this limited to that or is it general?

MEMBER POWERS: The question is are they responsible for discovering these problems or responding to them once they are discovered. And I can't see what -- I just can't see any efficiency in waiting for a licensee to discover a problem.

MR. BELL: I might add -- well, I'll skip that one. There are also some areas where the NRC's proposals perhaps didn't go far enough. There is a change to the design certification change process where You could make generic changes that -- or NRC could that reduced regulatory burden. So this would be a slight expansion of the ability to change design certification through a notice and comment rulemaking.

But what is really needed is a process by which a vendor who is continually learning more about his design and is now implementing his design may identify changes that boy, I wish we would have done that and put that in the design certification. I sure wish there was a process for folding that back in there.

Well, there isn't. So what we think is that in addition to what the staff proposed, a provision that would allow changes that would enhance or extend standardization, which is, of course, a fundamental goal of this rule, is appropriate. So we will be making a proposal in that area.

Westinghouse, I believe, as I understand, has some generic changes to their design certification of this sort. And it would be nice to address those through a -- one time through a notice and comment rulemaking and not each time on every docket for a COL applicant.

Doing it up front one time is the best way to assure that -- well, it is efficient, it is the best way to ensure standardization as well. So that is an interesting one.

There is an area that wasn't addressed at all in the rulemaking that I think cries out for it. There is another change process issue. The design certifications, of course, also include features to address severe accident issues. In particular, You know, what happens in the unlikely event where material leaves the vessel and it is out where it shouldn't be.

So these types of things were considered in the design certification. They are built in there. And there is a process for controlling them so that they are preserved. The problem is the current criteria, there are questions about the scope of what those criteria are focused on.

The criteria use terms like substantial increase and credible accident. These terms aren't defined. And we're frankly struggling with -- remember we're in the phase where we are actually proceeding. We need to know how to implement every part of this regulation, especially the change process.

We are having trouble writing or even

proposing guidance in this area so we're still on two paths. Whether we can work with the criteria and come up with the proper guidance or our comments may actually propose alternative criteria.

We wrote these together with the NRC 12 years ago, maybe more. I think we are a lot smarter now. And we might have done it differently if we were doing it today. And, You know what? We are doing it today. So I mean we have that opportunity today.

There are -- the only other thing I would add is there are a couple of policy issues I would highlight and we will highlight in our comments. The first is another area where the rule, You know, barely touches upon but there is a great need. And it is the ability for a COL applicant to proceed with pre-construction activities.

Currently, you seek a limited work authorization from the NRC staff. And it might be so granted following the completion and issuance of a final environmental impact statement. And a ruling by the ASLB on this matter.

Those milestones occur too late in the process. In order for the companies and the vendors to efficiently construct these plants, moving from one phase to the next, there is a need to begin these pre-construction activities.

We're talking about site preparation, clearing the trees, building the roads, support buildings -- this is non-safety-related stuff -- sooner than they would be able to under the current requirements.

So, in fact we sat with the staff and tried to do some out-of-the-box thinking on this at a meeting April 18th. And we are polishing our ideas and our recommendations in this area. And plan to provide that this month as part of our comments on the rulemaking.

There is a great need, again, from a business perspective for these companies to be able to efficiently move from one phase to the next and construct these things and start building on time and finish on time. The other -- and I call it a policy issue because as we've discussed with the NRC staff, it is going to be a different way of doing business than before so that kind of, by definition, we are calling it a policy issue.

Another one is a -- it is a concern that we have about the finality at COL of information contained in an early site permit. As we read and understand more what the staff intends by the language in the rule, we are concerned that the staff intends to essential redo the environmental review that was done at ESP at the time of COL.

Our understanding is, based on the rules, based on NEPA which everybody says is different and I'm learning more than I ever cared to about the National Environmental Policy Act -- I can tell you it is different but what isn't different is if you have resolved an issue once and there are no changes or no significant new information, then it doesn't need to be reviewed again.

We are concerned about some of the things we are hearing or expectations of the staff in this regard. And so I think we are going to seek some rule clarifications in this area so that the value of the ESP doesn't go to zero. A lot of people are putting a lot of hard work into these things and we want it to stand up.

Obviously if there is significant new information effecting a prior conclusion about an environmental impact, there is a mechanism for dealing with that. But no need to review all the issues that were previously reviewed. So we will be highlighting at least those two very significant issues.

And I touched upon a couple others that I thought -- certainly some of my favorites and I thought might be yours -- and Dr. Kress, You picked out the one -- certainly one I was going to mention because the Committee has been interested in dose analysis.

MEMBER KRESS:Yes, that's one of my issues.

MR. BELL: Did I give you enough time to think of a couple more questions?

MEMBER KRESS: Well, let me ask you, there was some question -- comment from the earlier versions that I saw where industry would like to retain the flexibility for a combined license COL submittal not to have to reference either an early site permit or a certified reactor design. What's the purpose of needing that flexibility? And could you comment on how that helps you out having that flexibility?

MR. BELL: Well, in general, you know, flexibility is a good thing.

MEMBER KRESS: Yes, yes.

MR. BELL: And we don't rule out any licensing scenario.

MEMBER KRESS: Combined, the COL may come in and say here is my site. We don't have and ESCP. We don't have a reactor in mind yet. But we want to get this site approved.

MR. BELL: So he's likely to come in with an ESBWR which doesn't have a design search yet.

MEMBER KRESS: Yes, okay. Then what is an ESBWR like? You are saying --

MR. BELL: That is, of course, a real scenario --

MEMBER KRESS: Yes.

MR. BELL: -- that is actively being discussed. It is hard to imagine this other scenario. There is such a premium on the design certification reviews.

MEMBER KRESS: Yes.

MR. BELL: The staff portion and then the rulemaking. That's why you see every company planning to go forward only with at least the staff review in hand.

But might there be a scenario where for some new design you would go straight to the COL application, I guess that was the PBMR case. At the end of that process, they were also going to get not only a license but a certification for that design. So again there is a priority on the certification.

MEMBER KRESS: Yes.

MR. BELL: But there was a serious interest at that time in going straight to the COL.

But I know of no -- I certainly don't know of anybody who is thinking about that now.

MEMBER KRESS: There doesn't seem to be any difficulty in providing that flexibility.

MR. BELL: And no down side.

MEMBER KRESS: No down side.

MR. BELL: I see no down side in it.

We were consistently impressed and gratified at the flexibility that the rule displays. The framers, whether they were lucky or good, it has accommodated, as you have seen, and read in the papers, a number of different approaches.

And I think it needs to because there are a number of different regions of this country, business situations, regulated, non-regulated. So I think it needs to be flexible. And I think it is.

MEMBER KRESS: I think I've had my questions answered.

CHAIRMAN WALLIS: I'm glad you ended on a positive note there.

MR. BELL: I hope I wasn't too dour. There are a number of good things about this rulemaking. We're certainly going to highlight those as well and support those. But I think a number of ways that it can be improved.

CHAIRMAN WALLIS: Thank you very much.

MR. BELL: Thank you.

CHAIRMAN WALLIS: That's been very helpful.

MR. SNODDERLY: Excuse me, Graham, I just wanted to take a moment to thank Jerry Wilson and Nan Gilles for coming over and giving us this presentation. I think it really helps us to understand what the rule covers and doesn't. And it will aide us in our upcoming review of the COL guidance and its importance in helping us to prepare for future ESP and COL reviews. So thank you.

MEMBER APOSTOLAKIS: The regulatory guide you said will be in the draft form at the end of June?

MR. FISHER: Yes, actually there has been an ongoing series of workshops already. And we have sections already posted on our external website. There has been extensive interaction with external stakeholders already with the goal of a draft by this June.

MEMBER APOSTOLAKIS: Is the ACRS going to get involved at some point?

MR. FISHER: I think the answer to that is yes, George. But I think the draft that Bill Beckner is talking about is a goal of having the draft sections on the web in June. So I don't think there is going to be a hard copy -- to my knowledge, there is not going to be a hard copy of it available for an ACRS review at that point. At least that is what Joe Colaccino told me, Bill.

CHAIRMAN WALLIS: We can always print it. What's wrong with that?

MEMBER APOSTOLAKIS: We can always print it, yes.

MR. FISHER: I know that Dave Matthews signed out a letter today which I think lays out a more detailed schedule also. My point though was it is going to be very draft at that point.

MEMBER APOSTOLAKIS: Once it is issued, there will be a letter from the ACRS?

MR. FISHER: That is correct.

MEMBER APOSTOLAKIS: Okay. There has to be? I don't know. They say yes.

CHAIRMAN WALLIS: Any other points? While everybody has been thanking everybody, I thank everybody again for your participation enlightening us.

We are going to take a break. We don't need the transcript any more. Thank you very much.

(Whereupon, the above-entitled meeting was concluded at 4:55 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 532nd Meeting

Docket Number: n/a

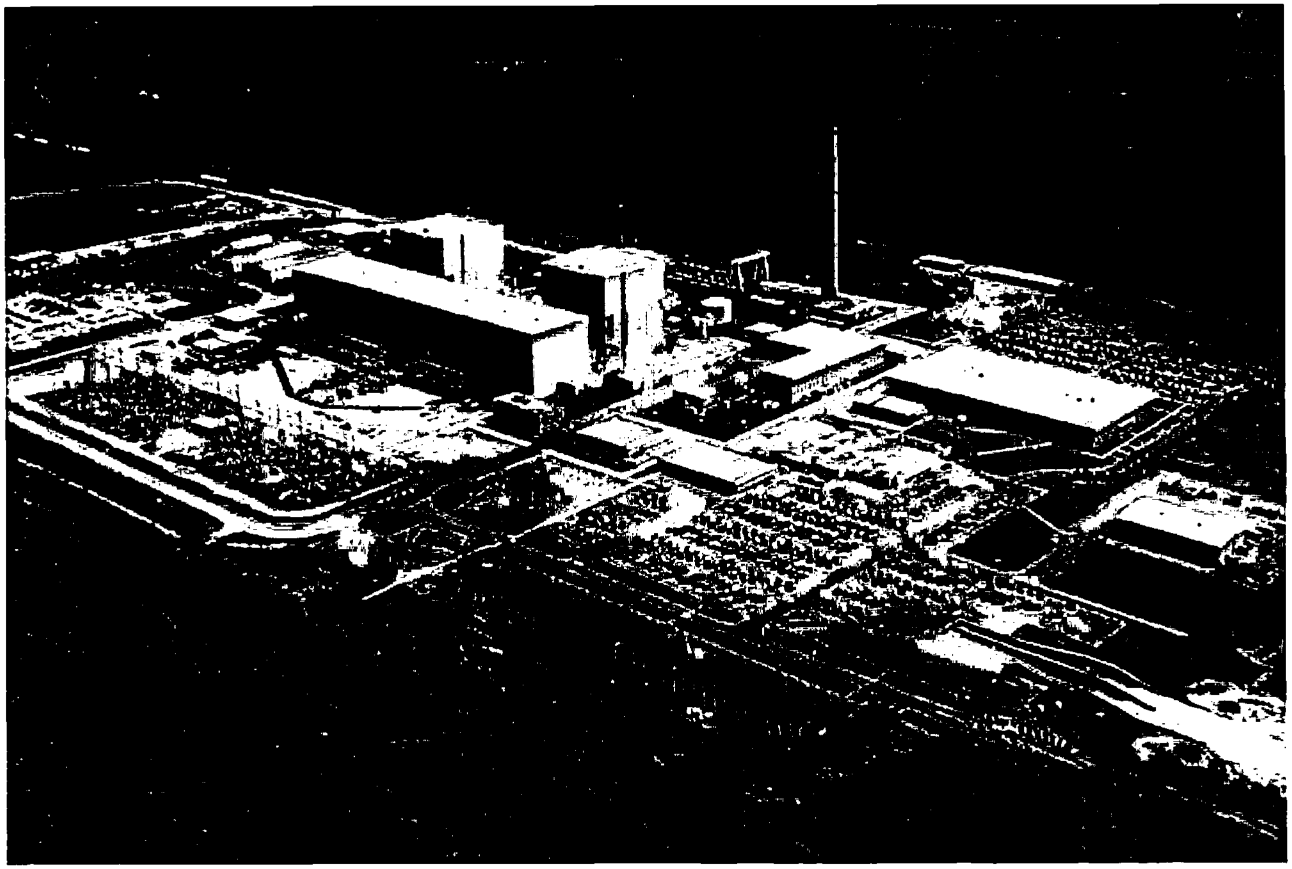
Location: Rockville, MD

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.

Eric Hendrixson

Eric Hendrixson
Official Reporter
Neal R. Gross & Co., Inc.

Brunswick Steam Electric Plant
Units 1 and 2



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Brunswick Steam Electric Plant
Units 1 and 2

License Renewal
Presentation to ACRS

NGG Nuclear Generation Group

Progress Energy

Agenda

- A. Overview of License Renewal Application
- B. Operating Experience
  - a. Drywell Liner
  - b. EPU Vibration
- C. Major Equipment Replacements/Repairs
- D. Major Exceptions to the GALL Report
- E. Commitment Tracking

INDEX

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
- Both units have achieved 120% power uprate
- Current License Expiration
  - Unit 1 September 2016
  - Unit 2 December 2014

INDEX

Application Background

- LRA used Class of 2003 Format – May 2003
- Information in the LRA was developed in plant calculations
- Addressed ISGs 1 through 20
- 34 Aging Management Programs Identified
- No Open Items or Confirmatory Items

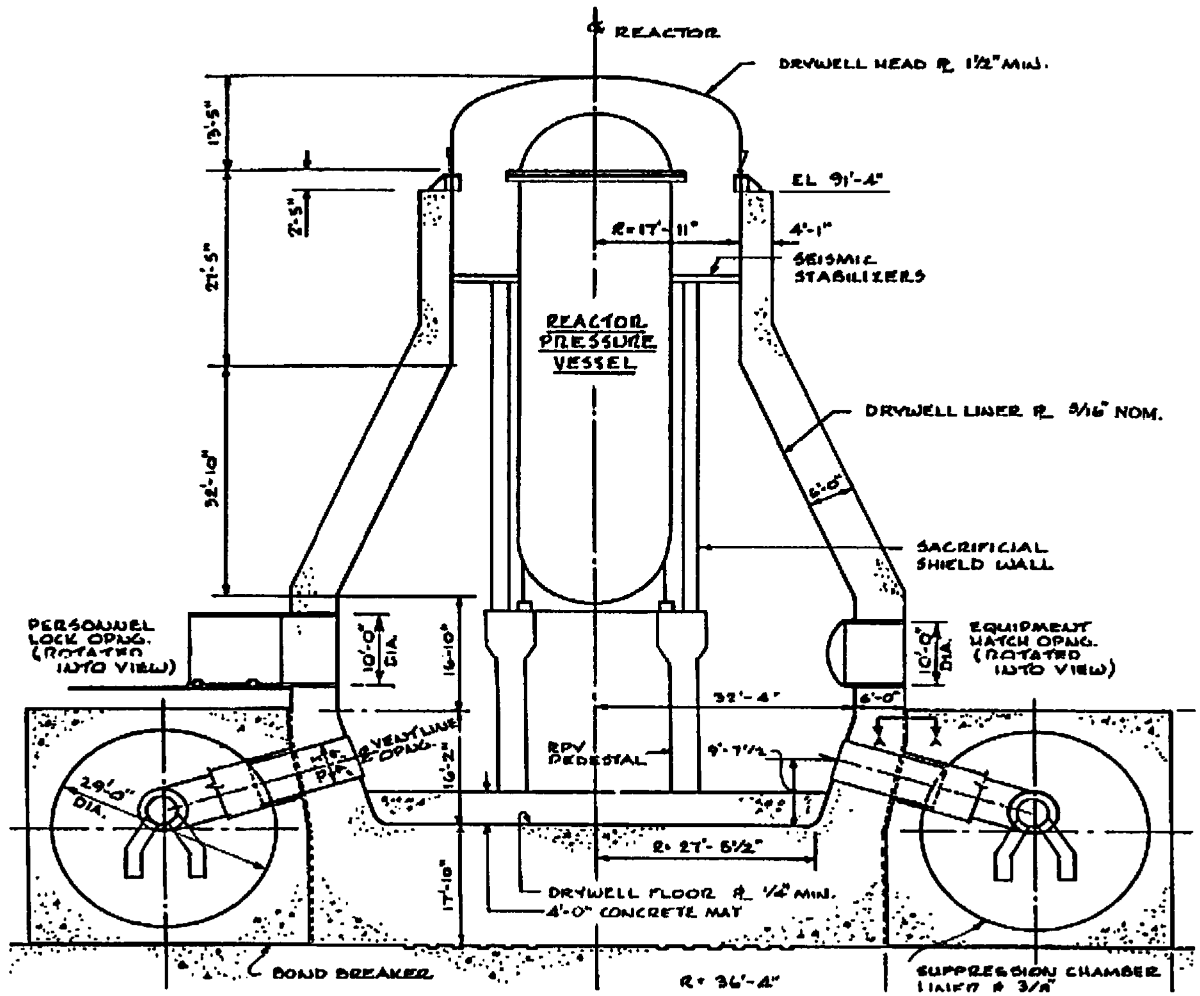
Drywell Liner Operating Experience

Tom Overton

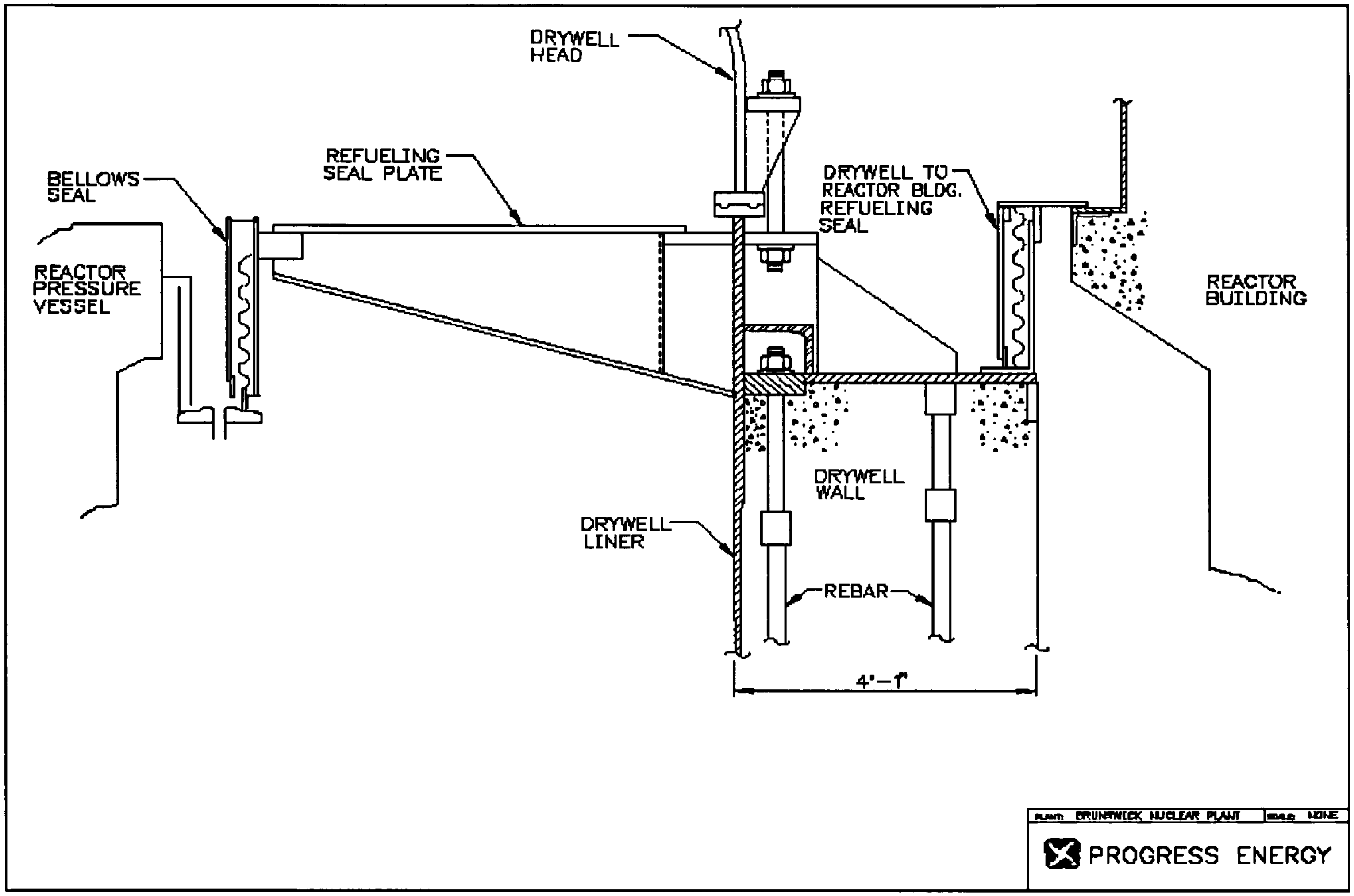
BWR Mark I Steel Lined Reinforced Concrete Containment

- Only BWR Mark I steel lined, reinforced concrete containment
  - No annular space between the metallic liner and the reinforced concrete
  - No sand bed region

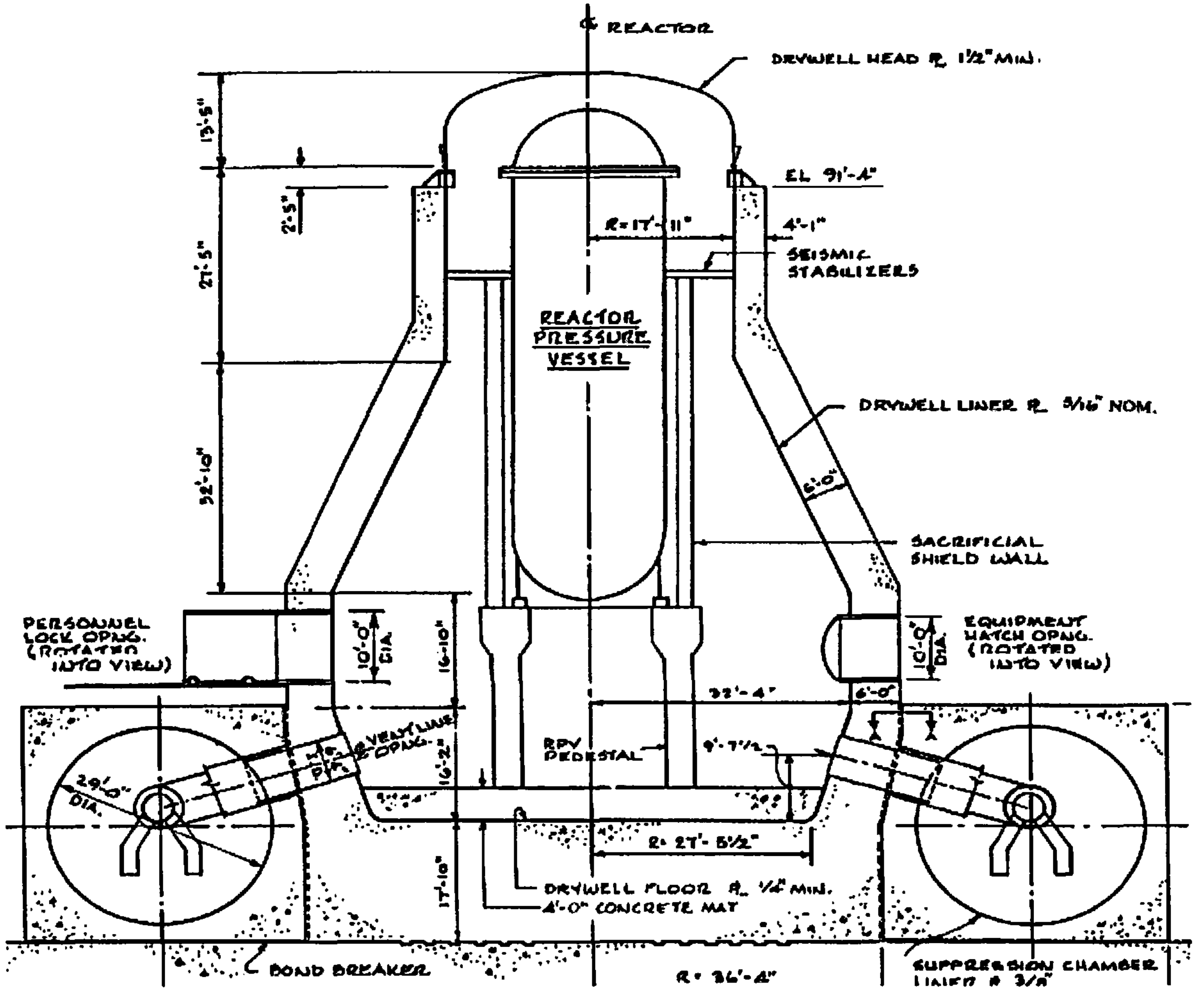
Brunswick
Mark I Steel Lined Reinforced Concrete Containment



Refueling Bellows



Brunswick
Mark I Steel Lined Reinforced Concrete Containment



Power Uprate Vibration Operating Experience

Mark Grantham

EPU Vibration Experience

- Main Steam and FW Vibration Monitoring
  - Based on ASME/ANSI OM Part 3
  - Modal analysis performed to determine sensor locations
  - Vibration levels increased as part of EPU implementation, but remain well below code allowable stresses

EPU Vibration Experience
Main Steam Line Piping

- Acceleration Study for Unit 1 Main Steam Node 26

Channel Number	Measured Acceleration at EPU (g)	Allowable Acceleration (g)	Percent of Allowable (%)
11	0.126	1.014	12.4
12	0.108	0.698	15.5

EPU Vibration Experience
Feedwater Piping

- Acceleration Study for Unit 1 Feedwater Node 37

Channel Number	Measured Acceleration at EPU (g)	Allowable Acceleration (g)	Percent of Allowable (%)
27	0.020	2.155	1.0
28	0.021	2.364	1.0

EPU Vibration Experience
BOP Piping

- 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

EPU Vibration Experience
BOP Piping

- Rod Hung BOP Piping
  - Low frequency vibration
  - Modified to add lateral supports

Major Equipment Replaced or Repaired

Mark Grantham

Major Equipment Replacement/Repair

- Replaced Power Range Neutron Monitoring System
- Replaced Main Power Transformers
- Replaced High Pressure Turbines
- Rewound Main Generator Stators
- Replaced FW Heaters
  - Unit 1 - 5 FW Heaters
  - Unit 2 - 1 FW Heater
- Replaced Reactor Feed Pump Turbines, Governor, and pump rotating assemblies

Major Equipment Replacement/Repair

- Replaced Condensate Pumps and Motors
- Replaced Isophase Bus Cooling Units
- Fire Detection System (in progress)

Major Exceptions to GALL

Mike Heath

Major Exceptions to GALL

Fire Protection Program

NUREG 1801:

- Visual Inspection of 10% of Each Type Penetration Once Every Refueling Outage.

BSEP:

- Visual Inspection of a Statistical Sample Once Every 18 Months.

Major Exceptions to GALL

Fire Protection Program – continued

NUREG 1801:

- Test Halon/CO2 Every 6 Months.

BSEP:

- Test Halon Annually/Test CO2 Every 18 Months.

Major Exceptions to GALL

Fuel Oil Chemistry Program

NUREG 1801:

- Internal Surfaces of Tanks are Cleaned and Inspected.

BSEP:

- Only Main Fuel Oil Tank Internal Surface is Inspected and Cleaned if Needed. Smaller Tanks Have External UT of Tank Bottom.

Commitment Tracking

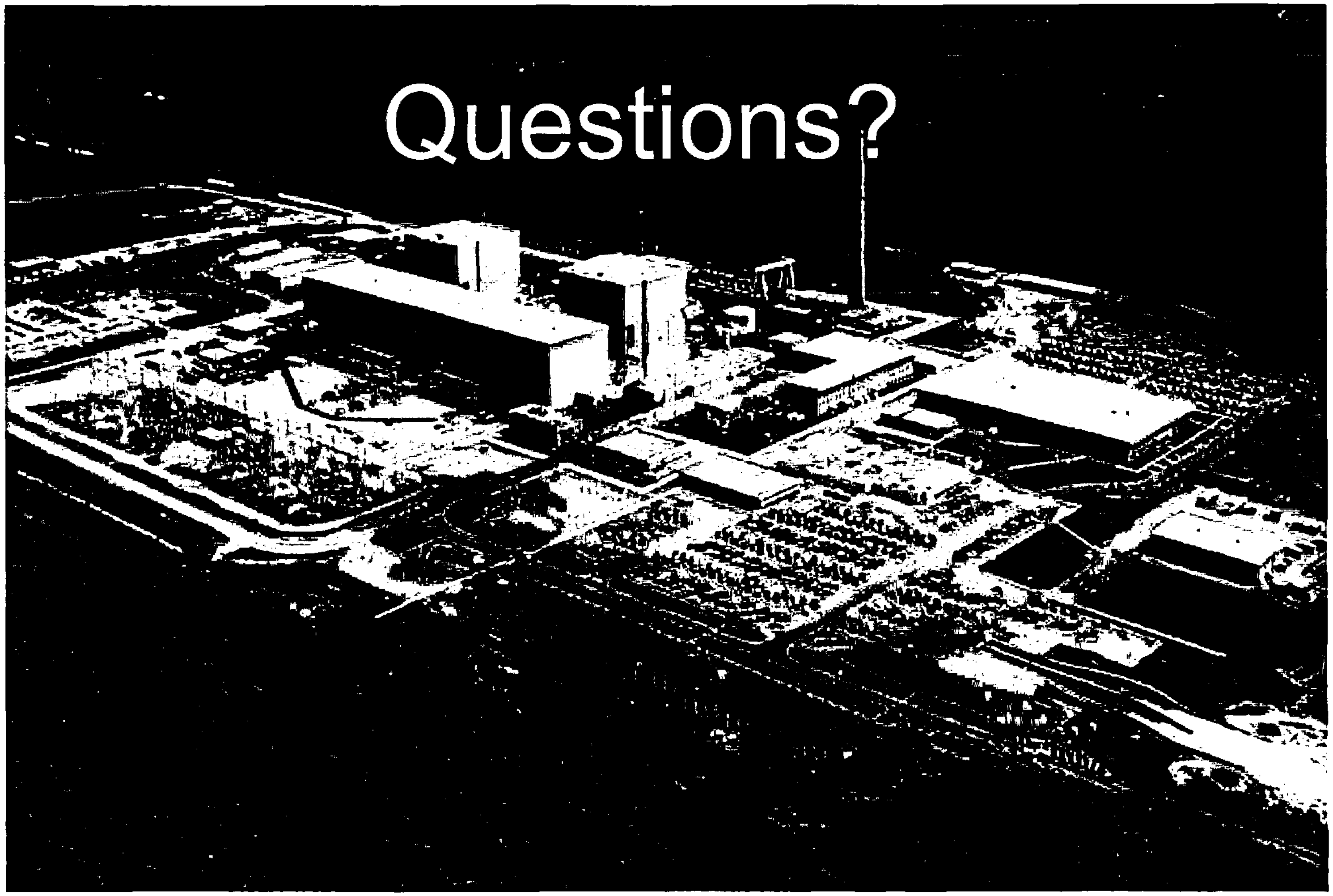
Mike Heath

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 Tracks LR Activities
- Most Document Updates Scheduled for 2006

Conclusion

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



Progress Energy

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

Staff Presentation to the ACRS Full Committee
Sikhindra (SK) Mitra, Project Manager
Maurice Heath, Project Manager
Office of Nuclear Reactor Regulation
May 4, 2006

Introduction

- Overview
- Highlights of the Review
- Time-Limited Aging Analyses (TLAAs)
- Conclusion

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
- FSER issued on March 31, 2006
  - Staff Conclusion: BSEP LRA has met the requirements of 10CFR Part 54

Highlights of Review

- Three (3) license conditions
  - FSAR update following the issuance of renewed license
  - Commitments completed in accordance with schedule
  - Reactor Vessel Surveillance Program
    - Implement Staff approved BWRVIP Integrated Surveillance Programs (ISP)
    - Obtain NRC staff review and approval for any changes to the capsule withdrawal schedule

Highlights of Review

- Items Brought into scope and subject to AMR
  - Switchyard Breakers
  - Service Water Intake structure fan, dampers, bird screen
  - Condensate Storage Tank Piping Credited for SBO

Highlights of Review

- 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)
- 39 out of 62 Mechanical Systems 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

Highlights of Review

- 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

- 8 Total Electrical Systems and Structures Continue to Receive Tier 2 review

Highlights of Review

	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
- Annual groundwater monitoring frequency for concrete structures

Highlights of Review

- Commitment # 22 defines which BWRVIP reports are included in the scope of the Reactor Vessel and Internals Structural Integrity Program (RV&ISIP) and additional specific augmented activities that will be taken by the applicant
- Added sample size of the augmented inspection for top guide that will focus on the high fluence region

Highlights of Review

- BSEP is Mark I Steel Lined Reinforced Concrete Containment
- 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.

TLAA - Reactor Vessel (RV) Upper Shelf Energy (USE)

RV Beltline Component	Acceptance Criterion for USE	Component Value for 54 EFPY	Acceptable (Y/N)
Brunswick 1 Lower Intermediate Shell Plate (Heat No. B8946-1)	Percent Drop <23.5 percent drop in the USE ft-lb value	21.0 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21(c)(1)(ii)]
Brunswick 1 Circumferential Weld FG (Heat No. 1P4218)	Percent Drop <39.0 percent drop in the USE ft-lb value	14.1 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21(c)(1)(ii)]
Brunswick 2 Lower Shell Plate (Heat No. C4500-2)	Percent Drop <23.5 percent drop in the USE ft-lb value	17.0 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21 (c)(1)(ii)]
Brunswick 2 Circumferential Weld FG (Heat No. S3986)	Percent Drop <39.0 percent drop in the USE ft-lb value	13.3 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21 (c)(1)(ii)]

TLAA - Reactor Vessel (RV) Upper Shelf Energy (USE)

RV Beltline Component	Acceptance Criterion for USE	Component Value for 54 EFPY	Acceptable (Y/N)
Brunswick 1 and 2 N-16 Instrument Nozzle Forgings	Neutron Fluence $<1.6 \times 10^{18}$ n/cm^2 (E>1.0 MeV)	Neutron Fluence $= 1.38 \times 10^{18}$ n/cm^2 (E>1.0 MeV)	Yes [TLAA satisfies 54.21 (c)(1)(ii)]
Brunswick 1 and 2 N-16 Instrument Nozzle Welds	Percent Drop <35.0 percent drop in the USE ft-lb value	12.0 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21 (c)(1)(ii)]

Conclusion

- On the basis of its evaluation of the license renewal application, the NRC staff concluded that the requirements of 10 CFR 54.29(a) have been met

Constellation Energy

Ginna Extended Power Uprate

ACRS Full Committee Meeting

May 4, 2006

The way energy works.

Ginna Extended Power Uprate

Dave Holm
Ginna Plant Manager
Introduction/Agenda Review

Agenda

• Introduction	Dave Holm
• Plant Changes	Mark Finley
• Safety Analysis	Mark Finley
• Mechanical Impacts	Jim Dunne
• PRA	Rob Cavedo
• Conclusion	Dave Holm

Introduction - Agenda

- Design and Operating History
- Preparations for Uprate

Introduction - Design and History

- Westinghouse two-loop 1520 MWt NSSS design
- Commercial operation in 1970
- 1300 MWt original licensed power
- 1520 MWt licensed in 1972
- 1775 MWt Extended Power Uprate (1)

(1) Kewaunee is operating at 1772 MWt

Introduction - Preparations for Uprate

- Replaced steam generators 1996
- Replaced reactor vessel head 2003
- Experienced project team:
  Westinghouse, Stone & Webster, Siemens
- Executive oversight:
  corporate, vendor, industry experts

Constellation Energy The way energy works.™

Ginna Extended Power Uprate

Mark Finley

Project Director

Plant Changes

Plant Changes-Agenda

- Operating Parameters
- Major Modifications
- License Amendments

Plant Changes-Operating Parameters

	EPU		Pre-EPU		
	Condition	Enthalpy	Condition	Enthalpy	Change
Core Power (MWt)	1775		1520		+16.8%
Taverage	574°F		561°F [1]		+13°F
Tcold / h cold (BTU/lb)	541°F	536.1	532°F	525.1	+9°F
Delta T	66°F		58°F		+8°F
Delta h		87.1		74.0	+17.5%
Thot / h hot (BTU/lb)	607°F	623.1	590°F	599.1	+17°F
Coolant Mass Flow (lb/hr)	6.96E+07		7.01E+07		-0.7%
Pressurizer Pressure	2250 psia		2250 psia		
SG Power (MWt)	1781		1526		+16.8%
FW In / h in (BTU/lb)	432°F	410.5	425°F	402.9	+7°F
Delta h		788.8		797.2	-1.2%
Stm Out / h out (BTU/lb)	798 psia	1199.4	770 psia	1200.1	+28 psia
Stm Mass Flow (lb/hr)	7.71E+06		6.53E+06		+18.0%

(1) Taverage was 573.5°F prior to SG replacement in 1996

Plant Changes - Major Modifications

- Fuel assembly
- Feed isolation valve actuators
- High pressure turbine and turbine control valves
- Main feedwater and booster pumps, feed regulating and bypass valves
- Cooling for main generator, step-up transformer, isophase ducts and underground oil cables
- Moisture Separator Reheater relief system
- Risk beneficial modifications: charging pump backup air, charging and TD AFW controls

Plant Changes - License Amendments

Change	EPU	Current
Core Thermal Power	1775 MWt	1520 MWt
LOCA Methods	BE LOCA/ASTRUM	BE LOCA/SECY-83-472
Axial Offset Control	RAOC (Relaxed)	CAOC (Constant)
Max Boron - Accumulator / RWST	3050 ppm	2600 ppm
Min Volume - Accumulator	1090 ft^3	1111 ft^3
Min Volume - Condensate Storage Tank	24350 gal	22500 gal
Feed Isolation Valve (Back-up Valve Stroke Time)	30 sec	60 sec
Safety Setpoints	Later in 'Safety Analysis'	Later in 'Safety Analysis'

Ginna Extended Power Uprate

Mark Finley
Project Director
Safety Analysis

Safety Analysis-Agenda

- Safety Setpoints
- Control Settings
- Methods
- Non-LOCA
- LOCA
- LTC
- Conclusion

Safety Analysis-Safety Setpoints (Analytical)

Setpoint	EPU	Current
High Flux Trip	$\leq$ 115%	$\leq$ 118%
Steam Line Isolation Hi-Hi	$\leq 5.97 \times 10^6$ lbm/hr	$\leq 3.70 \times 10^6$ lbm/hr
Steam Line Isolation Hi	$\leq 1.50 \times 10^6$ lbm/hr @ $\geq$ 530°F	$\leq 0.66 \times 10^6$ lbm/hr @ $\geq$ 543°F
Pressurizer Safety Lift Setting	$\leq$ 2542 psig	$\leq$ 2544 psig
Safety Injection	$\geq$ 1700 psig	$\geq$ 1715 psig
Containment Spray	$\leq$ 33.5 psig	$\leq$ 32.5 psig
P-8 Permissive (Single loop low flow)	$\leq$ 35%	$\leq$ 50%

Safety Analysis-Control Settings

Setting	EPU	Current
Pressurizer Level - Full Power - Zero Power	56% 20%	50% 35%
T_{Avg} - Full Power - Zero Power	574°F 547°F	561°F 547°F
Rod Control - Low Power Mismatch Gain - High	0.3 °F/% - 0.6 °F/% 1.5 °F/% - 3 °F/%	1.5 °F/% - 3 °F/% 5 °F/% - 10 °F/%
Steam Dump Modulation - Turbine Operating - Turbine Tripped	 4°F - 11°F 0°F - 11°F	 5°F - 20°F 0°F - 15°F
T_{Hot} Filter	4.5 sec	0 sec

Safety Analysis-Methods

Method	EPU	Current
Non-LOCA	RETRAN	LOFTRAN
Large Break LOCA	BE LOCA/ASTRUM	BE LOCA/SECY-83-472
Small Break LOCA	NOTRUMP	NOTRUMP
Control System Transients	LOFTRAN	LOFTRAN
Containment: LOCA MSLB	GOTHIC GOTHIC	GOTHIC COCO
Dose Assessment	AST	AST

Safety Analysis-Non-LOCA Approach

- Very conservative inputs for pre-EPU analyses used in EPU analyses where possible
- Certain limiting EPU analyses were not successful with pre-EPU inputs
- Inputs were adjusted until acceptable results demonstrated
- No attempt made to demonstrate additional margin
- Understand the conservative nature of methods, inputs and approved limits

Safety Analysis-Non-LOCA

	Event	Criteria	Result
Overheating (Reduced Primary Cooling)	Loss of Flow (Cond III) Locked Rotor (Cond IV)	DNBR $\geq$1.38 Pres $\leq$2997 psia	1.385 2782 psia
Overheating (Reduced Secondary Cooling)	Loss of Load (Cond II) (Bounds Loss of Feed) Feed Line Break (Cond IV) ATWS	Pres $\leq$2748.5 psia No T_{SAT} in HL Pres $\leq$3200 psig	2747 psia (No pzr fill) 2°F subcool 3193 psig
Overcooling	MSLB @ Power (Cond IV) (Bounds Increased FW/ARV)	DNBR $\geq$1.38 LHR $\leq$22.7 kw/ft	1.39 22.67 kw/ft
Reactivity Addition	Rod W/D @ Power (Cond II) Rod Ejection (Cond IV)	DNBR $\geq$1.38 Pres $\leq$2748.5 psia $\leq$200 cal/gm	1.381 2748.1 psia 178 cal/gm

Safety Analysis-Non-LOCA Loss of Flow DNB

CHF	1.0
Bounding Test Data- (95% probability/95% confidence)	1.17
Design Limit- accounts for parameter uncertainties (95/95)	1.24
Safety Analysis Limit- accounts for generic penalties with margin	1.38
Safety Analysis Result	1.385
Credit for Less Trip Delay	1.42
Credit for Overpressure	1.50

Safety Analysis-Non-LOCA Loss of Load Pressure

Potential Deformation- (ASME Service Level C Limit - Hot)	>3200 psig
Hydrostatic Test Pressure (Cold)	3107 psig
Design Limit- 110% of Design Pressure	2748.5 psia
Safety Analysis Result	2747 psia
Credit for Steam Dump and Pzr Spray	2605 psia
Credit for Steam Dump, Pzr Spray and PORVs	2565 psia
Credit for Reactor Trip on Turbine Trip	2348 psia

Safety Analysis-Non-LOCA

- All Non-LOCA results meet acceptance criteria
- Margin exists in the methods and the inputs
- Margin exists between the acceptance criteria and the failure point

Safety Analysis-LOCA

Results

- Large Break PCT 1870°F
- Small Break PCT 1167°F

Safety Analysis-Long Term Cooling

- The Ginna Design
  - High head safety injection (SI) pumps aligned to the RCS cold legs
  - Low head safety injection using the residual heat removal (RHR) pumps aligned to the upper plenum to provide upper plenum injection (UPI)
  - Simultaneous injection - both SI and RHR - will flush the core for all break locations, prevent boric acid concentration and assure Long Term Cooling

Safety Analysis-LTC-Large Break Analysis

- Mixing volume and void fraction calculated with Large Break LOCA code WCOBRA/TRAC
- No credit for mixing with UPI flow, no credit for beneficial effect of sump additives, no credit for containment pressure above atmospheric
- Credit for mixing with one-half lower plenum volume
- Time to reach boric acid solubility limit for atmospheric pressure is 6 hr 13 minutes
- Operators will restart SI beginning at 4.5 hours

Safety Analysis-LTC-Small Break Analysis

- Mixing volume and void fraction calculated with Small Break LOCA code NOTRUMP
- 4" break conservatively used to bound all small breaks
- Boric acid concentration is calculated as a function of time
- No credit for beneficial effect of sump additives
- Credit for mixing with one-half lower plenum volume
- Time to reach boric acid solubility limit for atmospheric pressure is 6 hr 48 minutes
- Operators will depressurize to initiate UPI, or refill to initiate natural circulation, in less than 5.5 hours

Safety Analysis-Conclusion

- All safety analyses meet acceptance criteria
- NSSS and Emergency Safety Features are robust
- Results are consistent with Kewaunee

Ginna Extended Power Uprate

Jim Dunne

Project Lead Engineer

Mechanical Impacts

Mechanical Impacts-Agenda

- Steam Generator Vibration
- BOP Heat Exchanger Vibration
- Vibration Monitoring Program
- Flow Accelerated Corrosion

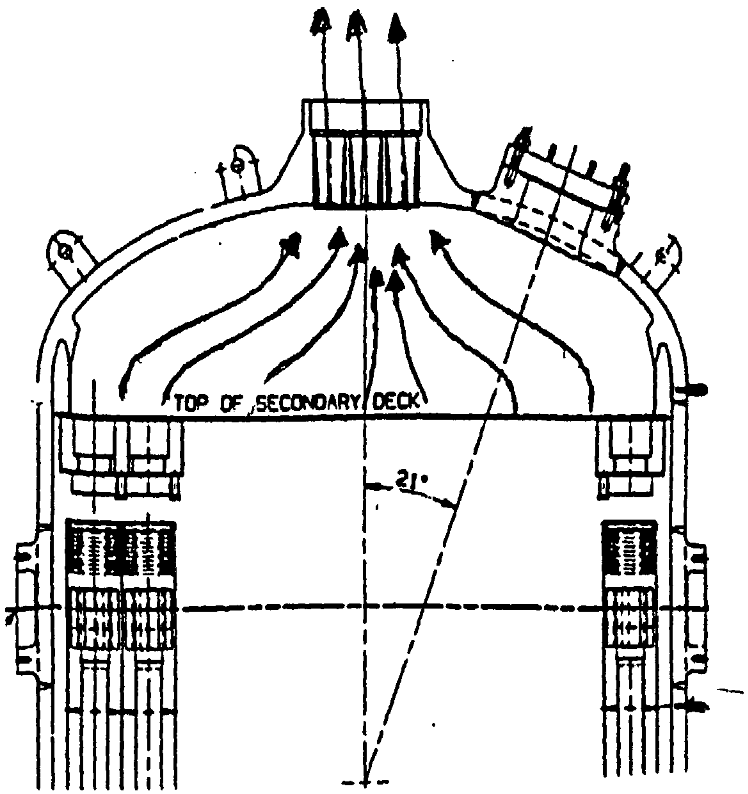
Mechanical Impacts-Steam Generator Vibration

- Steam Generator - Vibration
  - Vibration Potential in U-Bend & Tube Bundle Entrance
  - Fluidelastic Instability
  - Vortex Shedding (Tube Bundle Entrance)
  - Random Turbulence Excitation
  - Tube Wear (U-Bend Region)

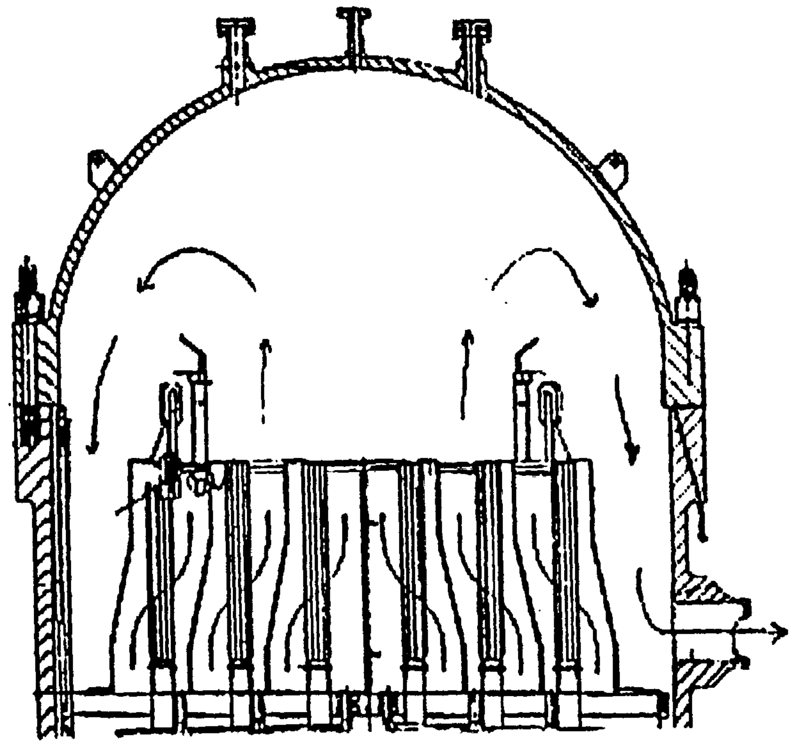
Mechanical Impacts-Steam Generator Separators

- Steam Generator Steam Separators
  - 85 Primary/Secondary Separator Modules
  - Primary & Secondary Centrifugal Type Separators
  - Minimal Cross-Flow Velocities
  - Rigid Separator Bundle
  - Full Scale Testing of Separator Modules
  - Up-rate Flow Bounded by Tested Flow Conditions

Ginna Separator / BWR Dryer Comparison



Ginna Steam Separators



BWR Steam Dryers

Mechanical Impacts-Vibration

- BOP Heat Exchangers - Vibration
  - Feedwater Heaters
  - Moisture Separator Reheaters
  - Condenser Tubing
- Vibration Monitoring Program
  - Pre-EPU Walkdown @ Full Power
  - Post EPU Walkdown (Pre- and Post-Full Power Levels)

Mechanical Impacts-Flow Accelerated Corrosion

- Flow Accelerated Corrosion (FAC)
  - Power Uprate effects evaluated using CHECWORKS
  - No component replacements required
  - Post Uprate Outage inspection sampling increased based on EPU conditions
  - Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates

Ginna Extended Power Uprate

Rob Cavedo
Risk Consultant
PRA

PRA-Agenda

- Scope
- Method
- Results
- Conclusion

PRA-Scope

- Address Impact On:
  - Initiating Event frequency
  - Success criteria
  - Equipment failure rates
  - Operator response times and Human Reliability Analysis (HRA)
- Identify Risk Beneficial Plant Changes
- Calculate the CDF and LERF Changes On:
  - Internal events
  - External events
  - Shutdown

PRA-Method

- Initiating Event Frequency
  - No new PSA initiators
  - Frequencies adjusted based on Engineering Evaluations
- Success Criteria
  - PCTRAN analyses to adjust success criteria as needed
  - Bleed-and-Feed Timing Adjusted

PRA-Method

- Equipment Failure Rates
  - Comprehensive reviews of equipment performed
  - Systems operate within allowable limits
  - No significant impact is expected to the likelihood of post-trip Equipment Failure Rates
- Operator Response Times / HRA
  - PCTRAN analyses to determine available action times
  - Higher decay heat reduced operator action times

PRA-Method

- Plant Beneficial Changes Identified and Incorporated
  - Use of high pressure SI pumps
  - Adjustment of RHR AOV
  - Addition of Back-up Air Supply for Charging Control

PRA-Results

Case	Pre or Post Uprate	CDF	LERF	Optimize SI Pump in Fire	Limit RHR AOVs	Back-Up Air to Charging
Base	Pre	6.36E-05	4.88E-06	No	No	No
Base	Post	7.12E-05	5.35E-06	No	No	No
SI	Post	6.40E-05	4.73E-06	Yes	No	No
SDAOV	Post	6.59E-05	5.32E-06	No	Yes	No
BK-IA-CHG	Post	7.10E-05	5.20E-06	No	No	Yes
SI-AOV-IC	Post	5.85E-05	4.56E-06	Yes	Yes	Yes

From EPU Submittal: Table 2.13-21

PRA-Conclusion

The Plant Risk Level Pre-EPU without the modifications is higher than the Risk Level Post-EPU with modifications

Ginna Extended Power Uprate

Dave Holm
Ginna Plant Manager

Conclusion

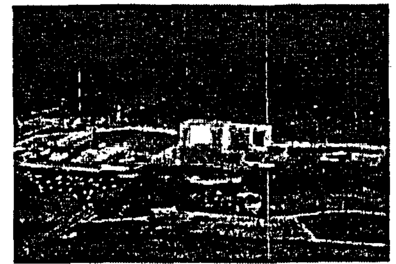
Conclusion

- Detailed and comprehensive reviews have been completed
- No safety issues were uncovered
- Comprehensive testing will be performed
- Ginna safety and reliability will be maintained through plant modifications, procedure changes and training

532nd Meeting of the Advisory Committee on Reactor Safeguards

NRC Staff Review of Extended Power Uprate Application
For
R.E. Ginna Nuclear Power Plant

May 4, 2006



Introduction

Patrick D. Milano

Senior Project Manager

Divsion of Operating Reactor Licensing

Office of Nuclear Reactor Regulation

Agenda -Topics

- Licensee Introduction
- Plant Modifications to Support Uprate
- Safety Analyses
- Mechanical Impact
- Probablistic Risk Assessment
- Other Evaluation Items
- Summary

Reactor Systems Analyses

- Fuel and Nuclear System System Design
- ECCS and Other Associated Systems
- Non-LOCA Transients
- LOCAs
- ATWS

Reactor Systems Review

Matrix 8 of NRC Review Standard RS-001

- **NRC Review Confirms:**
  - Use of NRC-Approved Codes and Methods for Plant-Specific Application
  - Compliance with Limitations or Conditions on Code Use
  - SG Plugging and Asymmetry Accounted in Analyses
  - Licensee's Evaluation of any Vendor Service Advisories
  - Appropriate Analytical Assumptions
  - Results Meet Applicable Requirements
  - Processes to Ensure Analyses Bound As-Operated Conditions
  - Boron Precipitation
  - Long-Term Cooling

Fuel and Nuclear Design

- **Continuity: WCAP- 9272-P-A, "Westinghouse Reload Safety Evaluation Methodology"**
- **Changing Fuel Design from OFA to 14X14 422V+**
- **Notable Differences between OFA and 422V+**
  - 14X14 422V+ Assembly Loss Coefficient is 20% less
  - VIPRE-01 replaces THINC IV Codes
  - Transition Core DNBR Penalty
- **Notable Similarities**
  - RTDP and WRB-1 DNB Correlation
  - STDP and W-3 DNB Correlation
  - DNBR Limits

Non-LOCA Transients

- **Followed the Guidelines of RS-001**
- **Most Events Analyzed with RETRAN and VIPRE**
  - Both NRC-approved
  - Not LOFTRAN and THINC
- **Important to Analyses and Evaluations:**
  - 1817 MWt (19% uprate) assumed in analyses
  - Steam generators replaced in 1996
  - License renewal in 2004 (term extended to 2029)
  - Fuel transition concurrent with EPU
  - Full-power Tavg operating window (564.6 °F to 576.0 °F)
  - Assumed up to 10% tube plugging in steam generators
- **Results Satisfied the Applicable Requirements and Design Limits of TS 2.1 (Safety Limits) for Peak CL Temperature, DNBR, and RCS Pressure**

Large-Break LOCA

- Analysis results for a double-ended guillotine break at the pump discharge
- Implemented Westinghouse Best-Estimate Large-Break LOCA Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)
- Conducted for a mixed core consisting of OFA and 422V+ fuel
- Met the acceptance criteria for ECCS performance, as specified in 10 CFR 50.46:
  - calculated peak cladding temperatures (PCTs)
  - maximum cladding oxidation (local)
  - maximum core-wide cladding oxidation

Small-Break LOCA

- Short-Term Behavior
- Within Limits of 10 CFR 50.46
- Confirmed Non-Limiting with Staff's RELAP5/MOD3 Analysis
- Post-LOCA Long-Term Cooling

Mechanical Impacts

- **Flow-Accelerated Corrosion**
  - Corrosion rates for FAC-susceptible components are determined by parameters such as temperature, flow velocity, moisture content, and component material
  - Components have been added to the program based on the potential for increased FAC rate at EPU conditions (higher temperature and velocity)
  - CHECWORKS computer models are being updated prior to implementing the EPU.
  - At EPU conditions the FAC program remains consistent with industry guidelines.

Mechanical Impacts

• Flow-Induced Vibration

- Main Steam and Feedwater piping instrumented at critical locations to monitor vibration levels at current rated power and during EPU power ascension, up to the full authorized power level.
- Vibration monitoring and collected data will be evaluated according to ASME OM3 Code
- FIV effect on steam separator expected to increase at EPU. However, judged to be acceptable based on the design basis steam flow rate of the replacement steam generator that is bounding for EPU
- Slight increase in FIV on the U-bend tubing, but remains within allowable limits (i.e., maximum stability ratio less than the limit of 1.0)

Mechanical Impacts

Steam Generator Dryer/Separator

- Flow rate and pressure used in testing bound EPU conditions
- Past inspections performed in operating plants not found FIV fatigue
- Integrity of rugged steam separators improved in new SG design
- Low flow velocity makes potential for loose parts to enter main steam line unlikely
- Low velocity and high stiffness reduces potential for FIV
- Capability to identify degradation of SGs through plant monitoring and outage inspections
- Filtering screen ensures collection of small parts in steam flow in unlikely event of degradation of SG internal components

Ginna EPU Risk Evaluation

- **Ginna PSA Level I covers:**
  - Internal Events, including Internal Floods
  - External Events
  - Shutdown Operations

- **Ginna PSA uses a simplified containment event tree to evaluate LERF**
  - Follows NUREG/CR-6595 for PWRs with a large dry containment

PRA Insights

- Licensee used the Ginna EPU risk evaluation to gain insights and proposed plant modifications and operational improvements that could reduce risk
- 5 risk and cost beneficial changes identified that would likely completely offset EPU risk increase
  - Optimize use of safety injection pumps during fires
  - Mechanically limit RHR HCVs from failing completely open
  - Provide backup air supply to charging pumps
  - Relocate charging pump control power disconnect
  - Install local controls for the turbine-driven auxiliary feedwater pump discharge motor-operated valve

PRA Conclusion

- Licensee adequately modeled and addressed potential risk impacts of the proposed EPU
- Risks are acceptable (i.e., within RG 1.174 risk acceptance guidelines)
- Proposed EPU does not create "special circumstances"
- Licensee used its risk evaluation to identify potential changes that would offset any risk increase due to the proposed EPU

Other Key Items

- Balance-of Plant
- Operator Actions and Procedures
- Testing
- Inspection

BOP Scope of Review

- **Review per RS-001, Matrix 5**
  - Internal Hazards
  - Fission Product Control
  - Component Cooling and Decay Heat Removal
  - Balance-of-Plant Systems
  - Waste Management Systems
  - Emergency Diesel Fuel Oil Storage & Light Loads

BOP ReviewAreas of Emphasis

- **Areas Affected by Increased Decay Heat Load**
  - Spent Fuel Pool Cooling
  - Service Water System
  - Auxiliary Feedwater
- **Operational Considerations**
  - Feedwater and Condensate Systems

BOP REVIEW RESULTS

- Decay Heat Load Will Not Exceed Cooling Capability of Systems that are Relied Upon

- BOP Systems will not Pose Increased Challenges to Reactor Safety Systems

- Power Ascension and Transient Test Program Provides Adequate Assurance of BOP Performance Capability

Operator Actions and Procedural Improvements

- **Revisions to Emergency and Abnormal Operating Procedures**
  - automatic action verification steps in E-0 procedure to expedite diagnosis and plant stabilization
  - R-H.1, "Response to Loss of Secondary Heat Sink," to provide earlier initiation of SAFW System to mitigate high energy line break
  - Appendix R mitigation procedures enhanced for effectiveness of operator actions and to incorporate the physical plant changes
  - ES-1.2, "Post-LOCA Cooldown and Depressurization" to direct operators to initiate cooldown of RCS using condenser dump valves (or ADVs if condensers are unavailable) within 1 hr of SBLOCA
  - ES-1.3, "Transfer to Cold Leg Recirculation," to instruct operators to reestablish cold leg SI no later than 5.5 hours after the termination of SI in the cold leg to prevent boric acid precipitation

Operator Actions and Procedural Improvements

- **For LB LOCA and SBLOCA**
  - Operators to realign HHSI for cold leg injection within 10 minutes
  - Times were unaffected for overall operator actions, but procedure and plant modifications being made to maintain operator capability to perform actions in the established time
  - Operator training related to EOP changes to be conducted prior to EPU implementation
  - All times for operator actions affected by EPU modifications and procedure revisions to be validated using simulator and plant walk throughs prior to EPU implementation

Power Ascension and Test Program

- **SP 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," provides guidance based on Regulatory Guide 1.68 and plant specific initial test program.**
- **EPU test program**
  - includes testing sufficient to demonstrate structures, systems, and components will perform satisfactorily at the proposed power level
  - considers in part, original power ascension test program, and EPU related plant modifications
- **Manual turbine trip test at 30% EPU power to verify the plant's dynamic transient response and control system settings.**
  - pressurizer level and pressure control,
  - steam generator water level control,
  - steam dump control, and
  - rod control

Power Ascension and Test Program

Conclusion

- The staff concludes that the proposed test program provides adequeate assurance that the plant will operate in accordance with its design criteria and that SSCs affected by the proposed EPU will perform satisfactorily in service.

NRC Inspection

- **Conducted by Resident Staff and Regional Specialists**
- **Inspection Procedure 71004, "Power Uprates"**
  - Describes inspections necessary for power uprate related activities
  - Provides guidance in conducting these inspections
- **Recommended Areas for Inspection**
  - Consider recommendations listed in final safety evaluation when selecting a sample for implementing IP 71004
  - These recommendations do not constitute inspection requirements
  - Provided to give the inspectors insight into important bases the NRC staff used for approving the EPU
  - Examples

532nd Meeting of the Advisory Committee on Reactor Safeguards

NRC Staff Review of Extended Power Uprate Application
For
Beaver Valley Power Station, Unit Nos. 1 and 2

May 4, 2006

Introduction

Timothy G. Colburn
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Agenda - Topics

- Licensee Introduction
- Plant Modifications to Support the EPU
- Safety Analyses
- Mechanical Impacts - FIV, FAC
- Probabilistic Risk Assessment
- Implementation
- Summary

Introduction

- Pre-application Submittals Included
  - Containment conversions to atmospheric
    - Approval of MAAP-DBA for M/E release
    - BVPS-1 relies on COP, BVPS-2 does not
    - Staff performed independent M/E release calculations
  - SG Replacement (BVPS-1 only)
- October 4, 2004 application with numerous supplements -Included full AST implementation
- Staff Review Followed RS-001, Revision 0

Reactor Systems Analyses

- Fuel and Nuclear System Design (No Changes)
- Non-LOCA Analyses and Transients
- LOCA Analyses
- ATWS
- ECCS
- Boron Precipitation
- Long Term Cooling

Reactor Systems Review

- Staff Review Using Matrix 8 of RS-001
  - No changes from NRC-approved Codes and methodologies
  - No changes to fuel design - No DNBR transition penalty
  - Uncertainties applied to initial conditions in conservative manner and conservative analyses metheods and transient assumptions were used
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  - There are acceptable margins in the safety analyses limits and the safety analyses results

Reactor Systems Review (cont.)

- Staff review looked at ECCS
  - Approach to control boron precipitation
- Large-break LOCA
  - Post-LOCA long term cooling (boron precipitation)
- Small-break LOCA
  - Short term behavior
  - Post-LOCA long term cooling (boron precipitation)
- Staff conducted independent analyses and audits of Westinghouse calculations

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- Followed the guidelines of RS-001
- Events analyzed with LOFTRAN and VIPRE
- Analyses considerations
  - 2917.4 MWt assumed in the analyses
  - BVPS-1 steam generators replaced spring 2006
  - Licensee qualified PZR safet valves for water relief during inadvertent SI actuation
- Results satisfied applicable acceptance criteria for peak clad temperature, DNBR, and RCS pressure

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- BELOCA methodology w/COBRA-TRAC
- Cold leg break limiting for boron precipitation
- Initiate simultaneous injection before boron precipitation occurs
- Increased minimum accumulator pressure and containment operating pressure partially offset increase in power
- Met 10 CFR 50.46 acceptance criteria for ECCS performance (PCT and cladding oxidation)

Small Break LOCA

- Analyses modeled using NOTRUMP
- Initial even-integer break size analysis expanded to include broader spectrum
- Initial model assumed broken loop seal clears for all SBLOCAs -licensee reanalyzed to assume only for certain SBLOCAs do loop seals clear
- Licensee increased accumulator pressure and SI injection flow to gain margin
- Staff independent calculations agree with licensee results - short term SBLOCA analyses and SBLOCA and LBLOCA long term cooling analyses meet 10 CFR 50.46 criteria
  - Identified need for EOP changes
  - Confirmed timing for boron precipitation

Mechanical Impacts

Flow - Induced Vibration

- MS and FW piping instrumented at critical locations and collected data are evaluated to ASME OM3
- FIV on steam separator typically increases at EPU conditions. FIV on steam separators is minimized due to its high stiffness and low flow velocity
- FIV on the U-bend tubing is within allowable limits (i.e. fluid-elastic instability ratio less than 1.0 and peak stresses less than the material endurance limit)
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- EPU conditions change the temperature, flow velocity, and moisture content for some components.
- Updated CHECWORKS computer models will determine future inspection and repair/replacement plans.
- The FAC program scoping criteria are consistent with industry guidelines (temperature, moisture content, component alloy content, amount of usage) at EPU conditions.

Scope of Risk Evaluation

- Full-power PRA model
  - Internal events, including internal flooding
  - Seismic
  - Internal fires
  - CDF and LERF
- Qualitative approach for other risk
  - High winds, external floods, other external events-screening per NUREG-1407
  - Shutdown risk-questions in SRP Chapter 19

NRC Staff Review of EPU Risk

- NRC onsite audit (10/05) to check quality of PRA and EPU risk assessment
- Minor impact on success criteria
  - Time to recover offsite power
  - AFW flow for ATWS (cavitating venturis)
  - Containment accident pressure credit for NPSH
- Less time available for some operator actions
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  - Validated important, short time available actions
  - HRA sensitivity analysis
- Important operator actions with short time available
  - Depressurize RCS
  - Implement feed and bleed cooling

PRA Conclusion

- Licensee assessed potential risk impacts of the EPU
  - CDF/change in CDF-very small
  - LERF/change in LERF-very small
- The EPU does not create special circumstances that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately addressed by the licensee and are acceptable

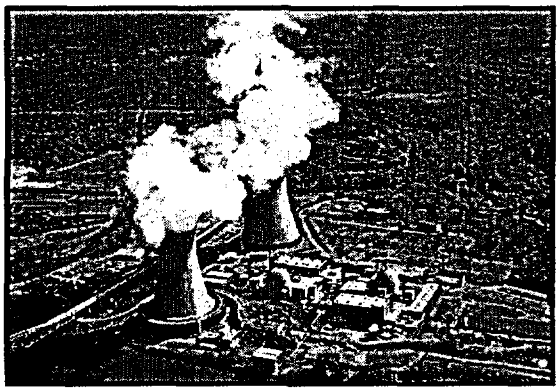
EPU Implementation

- Licensee will perform 2-phase implementation of EPU for both units
  - BVPS-1 will increase power 3 percent for the remainder of this operating cycle and will implement the remainder of the EPU increase next cycle (all BOP mods are currently complete)
  - BVPS-2 will increase power by 3 percent during the next operating cycle (following the fall 2006 RFO) and will implement the remainder of the EPU increase following all-reaction HP turbine mod (spring 2008 RFO)

Summary

- The staff reviewed the licensee's proposed EPU against the criteria in NRC Review Standard RS-001
- The licensee supplemented the application numerous times in response to staff requests for additional information-including providing revised analyses, additional commitments, and changes to the application
- Staff audits helped expedite reviews
- The licensee met all applicable review criteria of RS-001 for the uprated conditions

BEAVER VALLEY POWER STATION
Extended Power Uprate



ACRS

Full Committee Meeting

May 4, 2006

FENOC

Introduction & Overview

Pete Sena
Director, Site Engineering

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Agenda

• Introduction	• Pete Sena
• Plant Changes	• Mark Manoleras
• Safety Analysis	• Ken Frederick
• Mechanical Impacts	• Mike Testa
• PRA	• Colin Keller
• Conclusion	• Pete Sena

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Introduction - Agenda

- Beaver Valley History
- Beaver Valley Peer Units
- Preparations for Uprate

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Beaver Valley History

- Beaver Valley Power Station Units 1 and 2
- Westinghouse NSSS 3 loop Pressurized Water Reactor (PWR)
- BV-1 Commercial Operation - 1976
- BV-2 Commercial Operation - 1987
- 2652 MWt original licensed Rated Thermal Power (RTP)
- 2689 MWt Appendix K Margin Recovery - 2001
- 2900 MWt Extended Power Uprate (EPU) - pending

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Beaver Valley Peer Units - Power Uprates

Plant	Uprated NSSS Power Level (MWt)
Beaver Valley Units 1 & 2	2910
North Anna Units 1 & 2	2905
V. C. Summer	2912
Shearon Harris	2912
Vandellos	2954
ASCO Units 1 & 2	2952

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Preparations for Uprate

To Position BVPS Units for EPU:

Supporting Submittals Completed:

- •New Fuel Storage Rack Enrichment Limit Increase
- •Positive Moderator Temperature Coefficient
- •Accumulator and RWST Increased Boron Concentration
- •Selective Implementation of AST
- •Minimum Decay Time Before Fuel Movement
- •Relaxed Axial Offset Control (RAOC)

Replacement Steam Generators (RSG) BVPS-1

Containment Conversion

Large Break Best Estimate Loss-of-Coolant Accident (BELOCA) Methodology

Extended Power Uprate (EPU) - Pending

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WHAT'S NEW *inside BV Unit 1 Containment*

Take a look below at the improvements made inside Unit 1 Containment during Beaver Valley's 1R17 outage.

1) Three brand new 368-ton steam generators were installed. Shown here is the top portion of Steam Generator 'B.'
2) New catwalks on the steam generators will eliminate the need to build scaffolding, saving time and dose.
3) A new, simplified Reactor Vessel Head will save 12 polar crane lifts per outage in the future.
4) A new configuration for the Control Rod Drive Mechanism ventilation was installed.
5) The Cable Bridge will allow easier access to the head and will simplify the process of disconnecting the Control Rod Drive Mechanisms and Rod Position Indicators in future refueling outages.
6) New mirror insulation was installed on all three Steam Generators and the Reactor Vessel Head. The insulation will help keep heat inside the steam generators and debris out of the containment sump.
7) Steam Generator 'A.' Steam Generator 'C' is not shown.
8) Close to 1.4 miles of welds on the Reactor Coolant System, Main Steam System, Feedwater Lines and instrument tubing were completed.

Project Team and Oversight

- FENOC / BVPS
  - Overall project management
  - Review and approval of inputs
  - Proper interfacing of Information
  - Procedure / Training / Simulator updates
- Westinghouse, Stone & Webster, Siemens
- Oversight of the engineering and licensing process

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Plant Changes

Mark Manoleras
(Manager, Design Engineering)

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Major Modifications

- Replacement of charging/safety injection pump rotating assemblies
- Conversion from a sub-atmospheric to an atmospheric containment design
  - Installation of fast acting feedwater isolation valves (Unit 1)
  - Installation of auxiliary feedwater cavitating venturies (Unit 1)
  - Addition of reactor cavity drainage port
- Replacement of Steam Generators (Unit 1)

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Major Modifications

- Replace high pressure turbine with all-reaction design
- Install stakes in main condenser (Unit 2)
- Raise set-pressure of moisture separator reheater relief valves
- Increase Cv of main feedwater control valves
- Replace Turbine Generator (T/G) rotor and rewind stator (Unit 1)
- Instrument replacements for higher flow range

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Safety Analysis

Ken Frederick
(Nuclear Safety Analyst)

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Safety Analysis Objectives

- Demonstrate compliance with regulatory limits and acceptance criteria
- To show that BVPS will operate with adequate safety margins at EPU conditions

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Safety Analysis - Agenda

- EPU Operating Parameters
- Methods
- Non-LOCA Events
- LBLOCA
- SBLOCA
- Post LOCA Long Term Cooling
- Containment

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Nominal Operating Parameters (BVPS-1)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	577.9	576.2	+1.7F
Tcold (F)	544.6	545.1	-0.5F
Delta T (F)	66.6	62.2	+4.4F
Thot (F)	611.2	607.3	+3.9F
Coolant Mass Flow (total lb/hr)	1.11E+08	1.11E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	440	434.3	+5.7F
Stm Out (psia)	805	825	-20 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

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Nominal Operating Parameters (BVPS-2)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	574.2	576.2	-2F
Tcold (F)	538.9	543.4	-4.5F
Delta T (F)	70.6	65.6	+5F
Thot (F)	609.5	609	+0.5F
Coolant Mass Flow (total lb/hr)	1.05E+08	1.05E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	437	434	+3F
Stm Out (psia)	774	821	-47 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

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Safety Analysis Methods

Method	EPU	Current
Large Break LOCA	BELOCA/WCOBRA-TRAC	BASH (App K)
Small Break LOCA	NOTRUMP	NOTRUMP
Non-LOCA	LOFTRAN VIPRE	LOFTRAN THINC
Control System Transients	LOFTRAN	LOFTRAN
Containment	MAAP-DBA	MAAP-DBA (LOCTIC pre-CC)
Dose Assessment	AST/ARCON 96	TID/RAMSDELL

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Non-LOCA Acceptance Criteria

- Most Non-LOCA events are categorized as ANS Condition II for which the acceptance criteria are:
  - The critical heat flux is not exceeded (the calculated minimum DNBR does not go below the limit value at any time during the transient)
  - Peak heat generation rate remains within acceptable limits to prevent fuel centerline melt
  - Pressure in the RCS and main steam systems should be maintained below 110% of the design pressures
  - The event should not generate a more serious plant condition without other faults occurring independently

Non-LOCA DNBR Margin

DNBR		Corresponding Limit
1.55		Safety Analysis Limit
	Retained Margin	
1.22		Design Limit
	RTDP Uncertainties	
1.14		Correlation Limit (TS)
	Correlation Uncertainty	
1.0		Critical Heat Flux

WRB-2M DNBR LIMITS

Non-LOCA DNBR Results

DNBR Limited Events				
Event	DNBR Correlation	DNBR Limit	BVPS-1 DNBR	BVPS-2 DNBR
RCCA Bank Withdrawal from Subcritical	W-3,WRB-1	1.65, 1.45	1.83, 2.12	1.83, 2.12
RCCA Bank Withdrawal at Power	WRB-2M	1.55	1.57	1.58
RCCA Misalignment	WRB-2M	1.55	(1)	(1)
Loss of Load	WRB-2M	1.55	2.23	1.83
Feedwater System Malfunctions a. Feedwater Flow Increase b. Feedwater Enthalpy Decrease	WRB-2M WRB-2M	1.55 1.55	1.75 1.67	1.96 1.66
RCS Depressurization	WRB-2M	1.55	1.62	1.64
Main Steam Pipe Rupture (HFP)(2)	WRB-2M	1.55	2.56	2.56
Main Steam Pipe Rupture (HZP)(2)	W-3	1.61	2.41	1.83
Partial Loss of Flow	WRB-2M	1.55	2.25	2.25
Complete Loss of Flow	WRB-2M	1.55	1.64	1.64

(1) No DNBR Results-Analysis uses peaking factor limits for evaluation
(2) Condition IV event evaluated with Condition II limits

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Non-LOCA Pressure Results

Limiting Overpressure Events						
Event	Primary Pressure Limit (Psia)	BVPS-1 Peak Primary Pressure (Psia)	BVPS-2 Peak Primary Pressure (Psia)	Secondary Pressure Limit (Psia)	BVPS-1 Peak Secondary Pressure (Psia)	BVPS-2 Peak Secondary Pressure (Psia)
Loss of Load	2748.5	2747	2746	1208.5	1192	1191
Feedwater System Malfunctions	2748.5	2357	2353	1208.5	1124	1141
Partial Loss of RCS Flow	2748.5	2374	2361	1208.5	989	995
Complete Loss of RCS Flow	2748.5	2504	2503	1208.5	993	1003
Locked Rotor	2997	2797	2825	-	-	-
ATWS	3215	3060	2900	-	-	-

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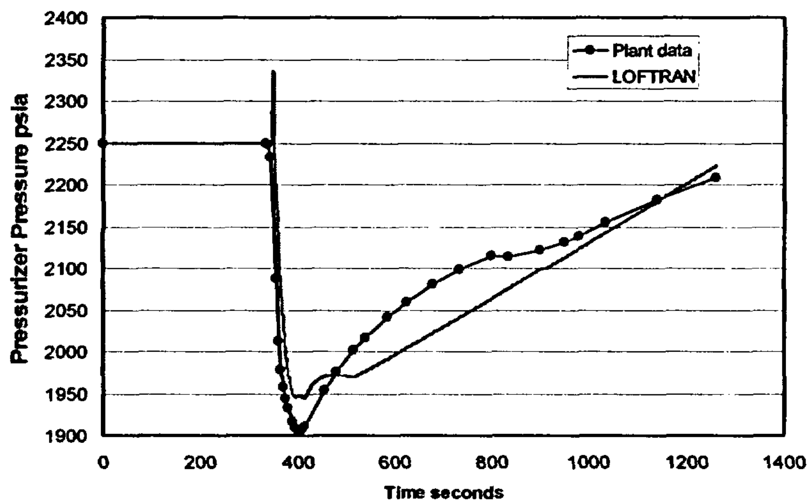
BVPS-2 Rx Trip on MUG Trip 4/2/2006



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Non-LOCA Other Results

Pressurizer Filling Events			
Event	Pressurizer Water Volume Limit (ft^3)	BVPS-1 Peak Pressurizer Water Volume (ft^3)	BVPS-2 Peak Pressurizer Water Volume (ft^3)
Loss of Normal Feedwater	1458	1384	1193
Loss of AC	1458	1224	1194
Spurious Safety Injection	1458	Pressurizer Fills	Pressurizer Fills
Margin to Hot Leg Saturation Event			
Event	Margin to Hot Leg Boiling Limit (°F)	BVPS-1 Margin to Hot Leg Boiling (°F)	BVPS-2 Margin to Hot Leg Boiling (°F)
Feedline Break	0 (No boiling)	14.4	36
Maximum Fuel Stored Energy Event			
Event	Max Fuel Stored Energy Limit (Btu/Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/ Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/ Lbm)
RCCA Ejection	360	326.8	326.8

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Non-LOCA Conclusions

- DNBR limits contain margin between safety analysis limits design limits to allow for core design flexibility
- Conservatism in peak pressure limits and analysis inputs allow for maintaining margins in operating limits
- All acceptance criteria for Condition II,III,IV Non-LOCA events are met at EPU conditions

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LOCA - Results

- PCT Results meet 10CFR50.46 acceptance criteria

Parameter	Current	EPU	Limit
Unit 1 Large Break PCT	1996 °F	2021 °F	<2200 °F
Unit 2 Large Break PCT	1908 °F	1976 °F	<2200 °F
Unit 1 Small Break PCT	1902 °F	1895 °F	<2200 °F
Unit 2 Small Break PCT	1902 °F	1917 °F	<2200 °F

- Oxidation results meet 10CFR50.46 acceptance criteria including consideration of pre-transient oxidation

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Long Term Cooling - Analysis

- Core voiding considered by reducing the mixing volume accordingly
- Time-based Mixing Volume / System Effects considered
- Effect of sump additives on Boric Acid solubility limit quantified but not credited
- Appendix K decay heat was used in all calculations

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Long Term Cooling Summary

- Post LOCA long term core cooling has been adequately addressed
- Results show the following for switchover time to hot leg injection:
  - BVPS-1 - 6.5 hours (8 hours pre-EPU)
  - BVPS-2 - 6 hours (7 hours pre-EPU)
- For small breaks, cooldown and depressurization can be accomplished within required switchover time

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Containment Analysis

- Containment will operate at slightly sub-atmospheric conditions
  - Prior to containment conversion 9 psia to 10.5 psia (air partial pressure)
  - Following containment conversion 12.8 psia to 14.2 psia
- Analysis credits plant modifications
  - Replacement Steam Generators (BVPS-1)
  - New feedwater isolation valves (BVPS-1)
  - AFW cavitating venturis (BVPS-1)
  - Reactor cavity drainage port
  - Lowered RWST level setpoint for transfer to SI recirculation
- Peak Containment pressures and temperatures within design for all accidents
- Containment Overpressure continues to be credited for BVPS-1

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Safety Analysis Conclusions

- All applicable acceptance criteria are met at EPU conditions
- Beneficial plant modifications have been made to maintain safety margins at EPU conditions

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Mechanical Impacts

Mike Testa
(EPU Project Manager)

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Mechanical Impacts – Agenda

- Steam Generator Vibration
- Piping and Component Vibration
- Flow Accelerated Corrosion

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Tube Bundle Region

- Unit 1 – Model 54F
  - Steam Generator installed in 1R17 (April 2006)
  - Designed for uprated conditions
- Unit 2 – Series 51M
  - Review for Flow Induced Vibration (FIV) affects showed acceptable results
  - Unsupported U-bends reviewed for increased fatigue
  - Increase in tube wear at Anti-Vibration Bar (AVB) interface evaluated

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Steam Dryer FIV Comparison

- Series 51/51M
  - Low Flow Rates Near Dryer vs BWR
    - Pre-Uprate – 3.5 ft/sec
    - Post Uprate – 4.1 ft/sec
    - *BWR ~ 100 ft/sec*
  - Low Turbulence Potential Vs. BWR
  - No Operational Issues Reported
    - 22 Domestic Plants
    - 74 Domestic SG
    - Operational from early 70's
- Series 54F
  - Low Flow Rates Near Dryer vs BWR
    - Pre-Uprate – 3.0 ft/sec
    - Post Uprate – 3.5 ft/sec
    - *BWR ~ 100 ft/sec*
  - Low Turbulence Potential Vs. BWR
  - No Operational Issues Reported
    - 6 Domestic Plants
    - 18 Domestic SG
    - Operational from mid 90's

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BOP Heat Exchanger Vibration

- Feedwater Heaters
- Moisture Separator Reheaters
- Condenser Tubing
  - BVPS-1 condenser tubes previously staked
  - BVPS-2 will be staked prior to power uprate

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Vibration Monitoring

- Monitor Secondary systems pre EPU
  - Baseline walk downs conducted on each plant
  - Areas of interest targeted for inspection under EPU
- Utilize guidance from ASME OM-S/G-2003, Part 3
- Collect and review data at each power escalation plateau
- Inspections will be augmented as required with vibration monitoring equipment
- Large equipment (e.g. Reactor Coolant Pump, Turbine) consistently monitored with existing plant instrumentation

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Flow Accelerated Corrosion

- EPU effects evaluated using CHECWORKS
- Turbine extraction steam tee proactively replaced
- Post Uprate Outage inspection sampling increased based on EPU conditions
- Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates

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PRA

Colin Keller
Supervisor, PRA

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Probabilistic Risk Assessment

- Scope of Assessment
  - PRA Model Elements
    - Initiating Event Frequency
    - Success Criteria
    - Equipment Failure Rates
    - Operator Response Times
  - Changes in CDF & LERF for each model

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PRA – Model Elements

- Initiating Events
  - No new initiators
  - No significant increase in Initiating Event frequencies due to the Power Uprate
- Success Criteria
  - MAAP analyses establishes EPU success criteria
  - No new accident sequences identified

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PRA – Model Elements

- Component and System Reliability
  - Comprehensive reviews of equipment performed
  - Systems operate within allowable limits
  - No impact on PRA failure rates or results
- Operator Response Times / HRA
  - MAAP analyses to determine operator action time available
  - Higher decay heat reduced times for some operator actions

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Summary of Changes (Unit 1)

BVPS-1 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	2.25 E-05	2.29E-05	3.36E-07
Internal CDF (/year)	6.25 E-06	6.55 E-06	2.97 E-07
External CDF (/year)	1.63 E-05	1.63 E-05	3.95 E-08
Fire CDF (/year)	4.62 E-06	4.66 E-06	3.89 E-08
Total LERF (/year)	4.37 E-07	4.95 E-07	5.83 E-08

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Summary of Changes (Unit-2)

BVPS-2 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	3.30 E-05	3.33 E-05	3.55 E-07
Internal CDF (/year)	1.86 E-05	1.89 E-05	2.92 E-07
External CDF (/year)	1.44 E-05	1.45 E-05	6.32 E-08
Fire CDF (/year)	4.89 E-06	4.95 E-06	6.38 E-08
Total LERF (/year)	1.03 E-06	1.07 E-06	4.61 E-08

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PRA Conclusion

- All PRA model elements reviewed for impact
- The increase in risk, due to the EPU for BVPS-1 and BVPS-2 is small compared to the current overall risk

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Concluding Remarks

Pete Sena
Director, Site Engineering

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Conclusion

- Detailed and comprehensive reviews have been performed
- No safety issues identified
- Beaver Valley Power Station safety and reliability will be maintained through plant modifications, procedure changes and training, and adherence to TS / Operating License

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End of Presentation

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532nd Meeting of the Advisory Committee on Reactor Safeguards

NRC Staff Review of Extended Power Uprate Application
For
Beaver Valley Power Station, Unit Nos. 1 and 2

May 4, 2006

Introduction

Timothy G. Colburn
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Agenda - Topics

- Licensee Introduction
- Plant Modifications to Support the EPU
- Safety Analyses
- Mechanical Impacts - FIV, FAC
- Probabilistic Risk Assessment
- Implementation
- Summary

Introduction

- Pre-application Submittals Included
  - Containment conversions to atmospheric
    - Approval of MAAP-DBA for M/E release
    - BVPS-1 relies on COP, BVPS-2 does not
    - Staff performed independent M/E release calculations
  - SG Replacement (BVPS-1 only)
- October 4, 2004 application with numerous supplements -Included full AST implementation
- Staff Review Followed RS-001, Revision 0

Reactor Systems Analyses

- Fuel and Nuclear System Design (No Changes)
- Non-LOCA Analyses and Transients
- LOCA Analyses
- ATWS
- ECCS
- Boron Precipitation
- Long Term Cooling

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- Licensee will perform 2-phase implementation of EPU for both units
  - BVPS-1 will increase power 3 percent for the remainder of this operating cycle and will implement the remainder of the EPU increase next cycle (all BOP mods are currently complete)
  - BVPS-2 will increase power by 3 percent during the next operating cycle (following the fall 2006 RFO) and will implement the remainder of the EPU increase following all-reaction HP turbine mod (spring 2008 RFO)

Summary

- The staff reviewed the licensee's proposed EPU against the criteria in NRC Review Standard RS-001
- The licensee supplemented the application numerous times in response to staff requests for additional information- including providing revised analyses, additional commitments, and changes to the application
- Staff audits helped expedite reviews
- The licensee met all applicable review criteria of RS-001 for the uprated conditions

PART 52 RULEMAKING

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Proposed Part 52 Rule

- Proposed rule published in *Federal Register* on March 13, 2006 (71 FR 12781)
- Supersedes proposed rule published on July 3, 2003 (68 FR 40026)
- Revised proposal result of comments on 2003 rule and lessons learned

General Overview

- Rewritten Part 52 contains five subparts:
  - Early site permits (ESPs)
  - Standard design certifications
  - Combined licenses (COLs)
  - Standard design approvals
  - Manufacturing licenses
- Appendices A-D are design certification rules
- Standardized organization and content of each subpart
- Made conforming changes throughout 10 CFR
- Generally kept technical requirements in Parts 50, 100, etc., and put procedural requirements in Part 52

Rule Objectives

- Revised rule will enhance the NRC's effectiveness and efficiency in implementing the Part 52 licensing processes
- Revised rule will provide clarity regarding the applicability of technical and procedural requirements to each of the Part 52 regulatory processes

Key Rule Proposals Affecting Safety Requirements

- Emergency Planning
  - Mitigation measures for significant impediments
  - ITAAC required with complete plans or major features at ESP stage
  - Updated emergency preparedness information at the COL stage
- Quality assurance requirements for ESP applicants
- Applicability of 10 CFR Part 21 to ESPs and design certifications
- PRA requirements for COLs