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NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates

Docket Number: (not applicable)

Location: Rockville, Maryland

Date: Tuesday, January 16, 2007

Work Order No.: NRC-1397 Pages 1-359

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

SUB-COMMITTEE ON POWER UPRATES

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TUESDAY,

JANUARY 16, 2007

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., Dr. Mario V. Bonaca, Chairman, presiding.

MEMBERS PRESENT:

MARIO V. BONACA, Chairman
GRAHAM B. WALLIS, Vice-Chairman (in absentia)
THOMAS S. KRESS, ACRS Member
MICHAEL CORRADINI, ACRS Member
OTTO L. MAYNARD, ACRS Member
JOHN D. SIEBER, ACRS Member

NRC STAFF PRESENT:

TIMOTHY McGINTY
EVA BROWN
DENNIS ANDRUKAT
HUSSEIN HAMZEHEE
MARTIN STUTZKE
MARK RUBEN
RICHARD LOBEL
ROBERT DENNIG
JOSE MARCH-LEUBA
GEORGE THOMAS
MUHAMMED RAZZAQUE
TAI HUANG
ZENA ABDULLAHI

ALSO PRESENT:

BILL CROUCH
ASHOK BHATNAGAR
ROBERT PHILLIPS
DAVE BURRELL
JOE VALENTE
RICH DeLONG
DAVID TILL
TONY ELMS
CRAIG NICHOLS

ALSO PRESENT: (CONT.)

JIM TATUM

FRAN BOLGER

DILIP RAO

DAN PAPPONE

JIM WOLCOTT

BILL EBERLEY

BILL MIMS

RANDY JACOBS

GREG STOREY

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Adjourn

P R O C E E D I N G S

8:32 A.M.

CHAIR BONACA: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Subcommittee on Power Uprates.

I am Mario Bonaca, Chairman of the Subcommittee for this uprate.

The Committee Members in attendance are Said Abdel-Khalik, Sam Armijo is not here yet. Sanjoy Banerjee, Dana Powers, Michael Corradini, Tom Kress, Jack Sieber. And Mr. Maynard and Dr. Wallis, they will be coming later because they've been blocked by the weather.

Poor Otto has had -- his house had no power for four days and the cover of his boat has collapsed on his boat. So he's trying to recover the boat, too.

The purpose of this meeting is to discuss the five percent power uprate application for the Brown Ferry Nuclear Plant Unit One.

The Subcommittee will hear presentations and hold discussions with representatives of the NRC staff and the Browns Ferry licensee, the Tennessee Valley Authority regarding these matters.

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

Ralph Caruso is the Designated Federal Official for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on December 21st and December 28th, 2006. Portions of this meeting may be closed to discuss proprietary information of PBA or its contractors.

A transcript of the meeting is being kept. It will be made available as stated in the Federal Register notice. It is requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

We have not received any requests from members of the public to make oral statements or written comments.

We will now proceed with the meeting and before I call upon Mr. McGinty of the NRC staff to begin, I would like to just make a couple of simple requests regarding the application. First of all, clearly the application, the SER we have reviewed leverages the 120 percent power application in many places, but it doesn't do so explicitly. It would be from my understanding is that only some analysis regarding fuel have been done specifically at 105 percent power.

So I would appreciate at some point during the meeting if the staff and the applicant would tell us exactly what analyses have been done at the 105 percent power because I understand there are exceptions, rather than the norm.

And the second issue, there are number of applications in the SER where some statement is made about an analysis that will be delivered by January 31st or whatever, which has not been delivered yet and I would like to have a clear statement that those are confirmatory items and not open items of any nature because, I mean, the SER is moot about that. It doesn't say what they are.

So with those two requests, I move on and turn it to Mr. McGinty.

MR. McGINTY: The intent of this briefing is for the staff to, as Mario said --

(Mic problems.)

MR. McGINTY: So with that said, the intent of this briefing is for the staff to provide some clarifications regarding several on-going issues to discuss the methodology used for the Browns Ferry power uprate submittal and the NRC staff review, provide a status of the three applications.

As a result of this briefing and the ACRS review, it is our desire that the ACRS be in a position to make a positive recommendation to the Commission confirming the staff's safety finding regarding the 105 percent uprate and selected 120 percent review areas. And outlining the additional information needed to be presented to the ACRS in future meetings, in support of the 120 percent extended power uprate submittals.

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As a way of background, the Browns Ferry site has three General Electric BWR design reactors with Mark 1 containments. Unit 1's operating license was issued on December 20th of 1973 with Unit 2's being issued the next year on August 2nd and Unit 3's being issued in 1976 on August 18th.

Today, the operating units, 2 and 3, are licensed to operate at a rated core thermal power of 3458 megawatts thermal, while Unit 1 remains shut down at the initial license thermal power of 3292 megawatts thermal.

Next slide, please.

All three Browns Ferry units were voluntarily shut down by TVA in March of 1985 to address performance and management issues. Following the shut downs, TVA specified corrective actions which would be completed prior to restart. All three units retained their operating licenses during respective long-term shut downs.

The restart efforts for Units 2 and 3 were both approximately five years in duration, with Unit 2 restarting in May of 1991 and Unit 3 following in November of 1995. The TVA Board of Directors decided to restart Unit 1 in 2002 time frame and soon thereafter discussions began with the staff to address their intent to not only restart Unit 1, but renew the operating license for all three units at extended power uprate conditions.

Next slide, please.

Regarding power uprate submittals, in a letter dated June 28, 2004, TVA requested a change to the operating license to increase the maximum authorized power level from 3293 megawatts thermal to 3952 megawatts thermal. This change would represent an approximate 20 percent increase above the previous maximum authorized power level.

Similarly, in a letter dated June 25,

2004, TVA requested a change that would increase the maximum authorized power level from 3458 to 3952 megawatts thermal. This represents an increase of about 15 percent above the current maximum authorized power level.

At this time, there are issues with the steam dryer analysis which will be addressed in more specificity later on in the presentation and it resulted in the decision of TVA to request an interim approval of five percent for Unit 1. This would allow Unit 1 to restart at the same power level as Units 2 and 3 whose five percent power uprates were completed on September 18 of 1998.

Next slide, please.

With respect to the schedule, the Unit 2 and Unit 3 extended power uprate are less complex and involve routine hardware modifications to the balance of plant and power generating systems, while Unit 1's modifications are much more extensive in that they include the replacement of miles of piping, conduit and cables over a thousand large valves and about 20 large pumps and 20 large motors.

The staff established an intended review completion date of spring of 2007 to ensure that the reviews were completed prior to the licensee's requested need dates which was originally spring of 2007 to support the restart of Unit 1; spring of 2007 for Unit 2; and the spring of 2008 for Unit 3.

Next slide, please.

Schedule changes regarding the Unit 1 implementation. Regarding the steam dryers, the NRC sent the licensee, TVA, a letter on December 1st of 2006 stating that TVA did not provide the requested steam dryer information in time to support the spring of 2007 need date. And the NRC would reestablish the extended power uprate review schedule when TVA provides a schedule for submitting that information. That includes a revised stress analysis report incorporating analysis of actual operating data that is being gathered from Browns Ferry Unit 2. TVA shut down Unit 2 in the fall of 2006 to collect that information and installed the instrumentation. Ongoing discussions with TVA suggest that the needed steam dryer information may be forthcoming in February of this year.

Next slide, please.

From a lessons learned perspective, from the standpoint of the staff review --

CHAIR BONACA: I'm sorry, could you go back to the previous slide?

MR. McGINTY: Yes.

CHAIR BONACA: You have at the bottom a bullet expectations. That describes what you are expecting them to deliver. Would you expand on that?

MR. McGINTY: On the expectation to instrument all three units?

CHAIR BONACA: Yes. I mean what your expectation is that they would instrument the three units and then go to 120 percent power and monitor.

MR. McGINTY: It is our -- all three units are being instrumented. We expect to process and have future meetings with the ACRS on the outstanding issues for the 120 percent power uprate submittals that are not clarified and adequately addressed at this meeting and to use the instrument -- to use the data gained from the units to support that, yes.

CHAIR BONACA: What I'm trying to understand is are you trying to monitor operation of the 105 percent power and then extrapolate some data? I'm trying to understand the methodology that you are expecting TVA to use to justify operation at the 120 percent power.

Or are you expecting them to simply instrument and then have step-by-step power escalation, monitor vibration at different levels up to 120 percent power and make the determination? I don't know.

MR. McGINTY: If I might defer to Eva, please.

MS. BROWN: Yes. Right now, the plan is that we are proposing a test program similar to what you saw in Vermont Yankee. The time frame may be a little different, but we really don't have the specifics yet as part of the EPU review is not complete.

So once we get the information that the licensee needs to support their request and validate their steam dryer analysis, at that point we'll be better able to tell you the scope and the type of testing that we expect. But right now, our thoughts are it will be very similar to what you saw at Vermont Yankee with stepped increases and monitoring at each step.

CHAIR BONACA: Okay, so you're looking really for the plan, for the program that you can agree to implement.

MS. BROWN: Yes. But I believe the licensee did provide -- Bill, if you want to step in, they did provide a program that I believe that we were pretty comfortable with. We just have not decided on the final details because we're still waiting for the rest of the information before we do.

Bill, did you want to add anything?

MR. CROUCH: My name is Bill Crouch. I'm the license manager at Browns Ferry. As Eva said, what we've talked to the staff about is doing a program very similar to VY where we will instrument each unit, we'll take data like at 105 percent, do the analysis, show that there's margin to move on up to the next step, collect data, do the analysis and move on up, looking to see if there's any anomalies like that.

CHAIR BONACA: Okay, I understand. The reason why I'm asking the question is clearly we were expecting to see 120 percent power uprate and then there has been a change, we're going to 105. And so I really was trying to understand what is the expectation. I mean why is it so time consuming that it will take months to define this. I think you are explaining it now and -- I've got some better understanding, all right.

MR. McGINTY: Okay, thank you. I will expand on that to some extent right now, at this point on the lessons learned slide, if you would.

CHAIR BONACA:

Okay.

MR. McGINTY: When we take a look at the amount of time that these applications have been with the staff, it's been an extended review and has taken quite an amount of time. This effort has been a reflection of many changes throughout the industry during these times. In 2004, the industry was struggling to find a resolution for several generic issues, including instrument set points and fuel methodology concerns, as well as steam dryer vibration issues.

The fuel methodology issue was a direct result of the staff's efforts to ensure that a code or methodology applied by a utility for a different use remained valid. This issue is still under review by the staff, but for the Browns Ferry Unit 1, 120 percent uprate penalties on several thermal limits will be imposed in the interim to address remaining uncertainties, until adequate data from the fuel vendor is obtained.

In the area of steam dryers, in 2004 through 2005, Vermont Yankee was the facility in the lead for the implementation of what at the time appeared to be a generic approach to steam dryer vibration issues. TVA and the staff monitored these efforts to identify insights from Vermont Yankee that could be applied.

Another lesson that the staff took away was that many utilities focus on the similarities of facilities which rather than necessarily the differences, at least from a staff viewpoint, that decide whether generic approach remains relevant for a particular facility. For Browns Ferry this is very much the case and very early on in this review, the staff spent a fair amount of time getting information from TVA in those areas where the uprate submittals differed from the guidance and from each other.

With that said, unless there's any further questions, I'm going to turn it over to Eva Brown. I'd again like to reiterate that our intent to provide more details on the staff review to address any items of outstanding confusion that have been created during this process, that the staff and TVA are both here to provide clarifications in that regard and our desire to again, to reiterate our desire to obtain positive recommendation with respect to the Unit 1 105 percent power uprate and clarification on any issues that remain for future 120 percent power uprate submittals for all three units.

CHAIR BONACA: Well, you make a big leap

there. I understand 120 percent power uprate for Unit 1. They already pointed out some of the complexities with a few.

MR. McGINTY: Yes.

CHAIR BONACA: And I understand that Unit 2 and 3 have not is the issue that they have a different kind of feel.

MR. McGINTY: Again, I'm trying to set the stage for future briefings in that regard and obtain clarifications for any outstanding issues in that regard.

MS. BROWN: Thanks, Tim. Good morning. My name is Eva Brown and I'm the lead for the Browns Ferry power uprates. Are you are aware, in 2002, the ACRS recommended that a standard review plan be developed for power uprates. This resulted in a development of our review standard, RS-001. This document outlines the staff's processes and expectations, points to a regulatory review and acceptance criteria and provides our draft safety evaluation template.

Back in 1995, General Electric submitted a topical report containing a generic evaluation for GE BWR extended power uprates. This EPU licensing topical report or ELTR was provided to the staff and supplemented a couple of times until NRC approval in the 1999/2000 time-frame. TVA used the approach presented in the ELTRs for the Browns Ferry upright request. The ELs differ slightly from what you're used to with the constant pressure power upright approach, which was approved in topical report NADC33004P, which was used for the Vermont Yankee EPU.

For Browns Ferry, the staff used our review standards, insights from the NRC approved EPU topical reports to determine whether submittals met the applicable acceptance criteria. Our conclusions were then compiled in the standard template provided in RS-001.

What we have here is a sort of graphic explaining our review. One challenge for our review was the submittal of two applications for facilities in differing states of operation, modification, and licensing basis. However, it was possible to find some commonalities.

Where possible, the staff was able to use the same approach and acceptance criteria to complete our review. As you can see for the 120 percent, most of the review was similar with the exception of issues in the areas of fuels, risk, containment overpressure, and large transient testing. It is our intent to address as much of both 120 percent reviews as possible.

CHAIR BONACA: Could you go back to that a moment? I have to digest it a little bit.

(Pause.)

DR. CORRADINI: Can you go back one more. Wasn't there -- so, I just wanted to understand you said it, and I just want to understand the logic. The logic is to look at this whole map of issues at 120 percent and back up where there is uniqueness for Unit 1 for 105. Is that what you said or did I misunderstand you?

MS. BROWN: That's close. You're a little bit, a little ahead of us there for where we're going with the 105. This graphic is just to explain the commonalities between the Unit 1, which come in for the 20 percent, and the Units 2 and 3, which were the 15 percent reviews. For a good part of the reviews, they were common. The acceptance criteria and the methodology that we used is exactly the same. And again, we are going to address 105, and for the most part, those analyses bounded the 105 review.

There are some areas around the outside that are unit-specific, and those resolutions we'll also discuss later on today, and fuels, risk, containment overpressure. And then on Unit 1, containment overpressure, risk, large transient testing and fuels.

DR. CORRADINI: And now back to the one, now back to the next one. That one.

CHAIR BONACA: Now you introduce risk here, and SER does not contain a discussion of risk. The application has a risk evaluation, I think is an erring evaluation. But that's specific to the back-pressure issue.

MS. BROWN: The 105 application did not have a risk component performed by the staff. They felt that the evaluation performed at 120 percent was adequate. For containment accident pressure, we did do some risk analysis.

CHAIR BONACA: Who did? I mean --

MS. BROWN: The licensee.

CHAIR BONACA: The licensee.

MS. BROWN: I believe we've looked at a little bit.

Bill, you guys did some risk for containment accident pressure?

MR. CROUCH: Yes.

MS. BROWN: We did some validation and verification of that information provided for that.

But routinely, we don't normally require, request a specific risk analysis for 105. And that submittal you saw was on the 120s.

So if we look at the overall method for power uprate, the licensee in their submittal listed these systems as being minimally affected, if at all, by power uprate which means that these systems are basically part of normal plant functions and are separate from and in general required whether the plant is at full power, partial power.

For others, the increase in power level does not significantly change or alter the performance requirements of these systems. However, the uprate may cause a small change in processed radiation or area monitoring, but the only effect on these two systems would be a slight change in the normal radiation activity reading, and the possibility of the need to increase shielding to minimize personnel exposure.

As will be mentioned several more times, the licensee's application is based on the EPU licensing topical reports. And just as the previous slide discussed, the minor impacts, the ELTRs also address the treatment of affected systems. For example, the generic evaluation for the low pressure systems, such as core spray and residual heat removal, indicated that the hardware is not affected. Injection setpoints do not need to be changed, and flow rates will not be increased as a result of the extended power uprate.

For the recirculation system, the maximum core rates are not increased on chief power uprate. The control rod drive system should see a better scram insertion time as a result of the higher reactor pressure. Reactor water cleanup is slightly affected, by the water print chemistry requirements should remain unchanged.

DR. ABDEL-KHALIK: Excuse me.

CHAIR BONACA: Go ahead.

DR. ABDEL-KHALIK: Where does the OPRM system fall in these two sets of systems that you have listed?

MS. BROWN: Whether or not they are affected by power uprate? The staff performed reviews independent of the uprate for the stability analysis. So the OPRMs for Unit 1, as a matter of fact, that's one of our little blanks in the 105 SE. Because I don't think at the time that we submitted you the draft that that evaluation was complete. But as far as effects, they were reviewed by the staff at 120 percent.

DR. ABDEL-KHALIK: So what's the answer?

MS. BROWN: About?

DR. ABDEL-KHALIK: Affected or unaffected?

MS. BROWN: I'm not sure. I'll have to get back to you on that. I don't think I have the staff here to specifically answer that, but we'll take a note and get back to you. Our folks in the fuels are going to be here this afternoon, and we'll be better able to discuss the effects of the power uprate on the OPRM.

CHAIR BONACA: Before you proceed, I have another question. You said before that you do not perform risk evaluation for the 105 percent power uprate?

MS. BROWN: Yes, sir.

CHAIR BONACA: However, the analyses presented and evaluated in the SER for the 105 percent power really is the one made at the 120 percent power. So why are we not talking about risk if the analysis for reviewing is 120 percent power?

MS. BROWN: What was necessary for the 105 percent review was what we included in the 105 SE. The insights and the increases from the 105 we didn't feel were necessary for the approval.

CHAIR BONACA: I went back to the calculations, and those calculations are the ones reported in 120 percent power.

MS. BROWN: Yes, sir. I was talking about the 105. I'm sorry.

CHAIR BONACA: And they're used now to justify 105 as a bounded case. Okay? And now it seems to me that the risk evaluations for 120 percent power is the same as 105 percent power because you're using the same NPSH when you're presenting the situation. So I'm confused.

MS. BROWN: We actually have a specific presentation to address how power uprate, how the risk impacts are applied to power uprate. I think it is going to be before lunch. And then we will have a discussion after lunch that addresses specifically our evaluation of risk and containment accident pressure.

CHAIR BONACA: I appreciate that. I know it's on the schedule, etcetera. I just bring it up to illustrate the confusion that all of this is creating. Okay, there are statements being made that are not supported by the evidence in the SER. I mean, I'm reviewing NPSH for 120 percent power and I'm questioning the credit being taken and the length of the credit. But it is really obscure there. There are statements which are not corresponding to inputs.

So, you know, we have to be careful that we do not get to the point where there is total obfuscation of where we are going here.

MR. McGINTY: And we agree, and as I've mentioned earlier, one of our primary objectives is to clarify any areas of confusion prior to this meeting.

CHAIR BONACA: Because, I mean, my concern is this. You may say this is only 105 percent power uprate, therefore we're not going to discuss risk associated with NPSH. Okay? And then we say fine. And then we get to the 120 power uprate, and you're going to say oh, we already reviewed that before, therefore we don't need to talk about it because the analysis --

MS. BROWN: No, sir. Not at all.

CHAIR BONACA: I'm not saying that you would do that intentionally. I am only saying that it is a possible outcome, and I really want to prevent that.

MS. BROWN: No, sir.

MR. McGINTY: And that illustrates the clarity of the communications during the conduct of these meetings and the full committee meetings subsequently. We agree.

MS. BROWN: Yes, sir. We actually have a dedicated risk presentation tomorrow afternoon on the 120 percent risk.

CHAIR BONACA: Which?

MS. BROWN: It's Mr. Stutzke. So you'll be hearing from him three times on risk aspects for different issues.

Okay, low pressure systems. While many issues in the submittals are generically resolved in topical reports, several other issues have been identified in a more unit specific analysis review required.

Many of these interesting points are not new and some issues have been discussed previously by the staff before the ACRS. Just like for Vermont Yankee, the resolution of these items has added an additional level of complexity to the review. We have attempted to focus our presentation today to address these topics.

CHAIR BONACA: Before you move on, large transient testing, I'm sure you will be discussing this later, right?

MS. BROWN: Yes, sir.

CHAIR BONACA: But the licensee had proposed one of the tests be done at the 120 percent power, 115 to 120. And you said no, we're going to do it at 105?

MS. BROWN: Yes, sir.

CHAIR BONACA: Does it mean they have to do it again at 120 later on?

MS. BROWN: It depends on the outcome of their 105 test. If they are completed satisfactorily, they should have a very good justification for not performing those tests again. But Mr. Tatum and Mr. Hussein Hamzehee will discuss that in a little more detail later on this morning.

CHAIR BONACA: Okay, thank you.

MS. BROWN: One of the unique features of the Browns Ferry uprates is the fact that these facilities had their operating licenses extended for an additional twenty years prior to implementation of the power uprate. This was not TVA's original intent. Back in 2002, the licensee had originally indicated that the EPUs would be submitted first and then the license renewal. However, TVA ended up submitting the license renewal on December 31, 2003, and the NRC approved it May 4th of last year.

Just like license renewal, the licensees analysis were performed at 120 percent. However, as a license renewal was submitted and approved before the EPUs, the license was renewed at the existing operating license power level, which was 100 percent for Unit 1 and 105 percent for Units 2 and 3. This has resulted in the staff having to add a license renewal review for the power uprates.

The staff, using some information provided during the license renewal review and through additional information requested, went back through the submittal, focusing on the time limiting aging analyses and aging management programs which might be affected by the uprate. As part of the aging management review, the staff required evaluation of EPU modifications to determine any impact from the conclusions reached in the license renewal application.

TVA performed reviews of the EPU mods for all three units. The progress of the mods ranged from design status to complete. These results indicated that no additional components, materials or environments were introduced. Therefore, the staff found that the aging management review completed during the license renewal review remained acceptable. Final reviews confirming this will be completed after implementation of all EPU modifications.

Earlier, we touched upon the licensee's

desire to restart Unit 1 this spring. As a result of additional information needed to support the 120 percent steam dry review, in September of last year the licensee requested an interim uprate of 5 percent. In this supplement, the licensee indicated that this request was bounded by the existing 120 percent analysis provided with the extended power uprate submittal in June 2004.

Therefore, last fall, the staff refocused our review efforts to verify that the information provided in the Unit 1 120 request remained bounding for the 105. This assumption was found to hold true with one possible exception in the fuels area. This exception will be discussed later on in the reactor systems presentation.

Just as before, for the 120 percent uprate, the staff's review was conducted using the same guidance and accepted criteria adjusted as necessary for the power level. In addition to the conservative 120 percent analysis performed by the licensee, the precedent established by the safe operation for several years of Units 2 and 3 at this power level provided additional comfort that the 105 percent submittal is acceptable.

Consistent with that, the staff compiled a safety evaluation using the template provided in the staff review standard.

CHAIR BONACA: Since you are talking about Unit 2 and 3 experience in several locations in the SER, you're saying that there isn't reason sufficient information yet from Unit 1, therefore, you rely on Unit 2 and 3 experience to draw conclusions. For example, if I remember pipe stress calculations, that's a typical example. Why -- at some point you have to explain why it's applicable. I mean is it the same materials? There have been a lot of changes in Unit 1 and I remember when we did license renewal that one statement was that the experience from Unit 2 and 3 have been used to make decisions regarding material selection for Unit 1. We have to understand why we have to rely entirely on Units 2 and 3 experience and not plant specific as Unit 1.

MS. BROWN: Bill, did you want to touch on that now?

MR. CROUCH: On the pipe -- for example, the pipe stress. At this point in time we've completed, we have now completed all the pipe stress evaluations. As you know, we were going through the restart process and so all the mods were being implemented and you have to go through and update the calculations at the end. Those have been updated now and we're in the process of closing all those DCNs, so we've got the pipe stresses done for Unit 1.

CHAIR BONACA: Yes, we will have to look at -- there are several cases of pipe stresses. That is a good example. And there was a commitment to delivery before the end of January, so you deliver the package?

MS. BROWN: Yes, sir. We received a letter, I believe it was last week, no, it was the week before, actually.

MR. CROUCH: A couple of weeks ago.

MS. BROWN: Addressing pipe stresses and that was one of our confirmatory action items that didn't have a date in SE.

CHAIR BONACA: Okay.

MS. BROWN: Let's see where are we? So what's left to do? The technical review for the 105 percent is complete. I know that the draft safety evaluation has some blanks for dates. These items are either pending letters addressing confirmatory items like the status of implementation or mods or where the review is some other technical area was performed under a separate review like the safety limit MCPR.

The technical review for these items which support Unit 1 through extended power uprate conditions is complete. Although the review has not been released to the public, the 120 percent technical review is complete with the exception of steam dryers and certain fuel issues.

We're aware that our constant scope and schedule changes have caused some confusion, but I just wanted to reiterate that it is our intent to return to this Subcommittee to discuss all remaining 120 topics with our primary focus on steam dryers and fuel issues.

With your favorable recommendation, we intend to issue the 105 percent Unit 1 uprate to TVA in February with 120 percent uprate tentatively scheduled for early summer. As you would expect, our ability to complete the 120 review is entirely dependent on the timely receipt of the additional information on dryers and fuels. At that time, we'll be able to better predict the time frame for issuance of the staff's 120 percent reviews.

CHAIR BONACA: Now you keep talking about 120 percent and are you making a distinction between the Unit 1 and Unit 2 and 3?

MS. BROWN: I'm sorry, could you ask that one more time?

CHAIR BONACA: When you talk about 120 percent power, you are referring to 120 percent power for Unit 1.

MS. BROWN: I'm referring to 120 percent power for all three units.

CHAIR BONACA: Now, so we need to understand and certainly will be in the future, but even now, I understand Unit 2 and 3 have different fuel for Unit 1?

MS. BROWN: Yes.

CHAIR BONACA: And some of the topical reports of GE may not be applicable. I mean there are standard reports on power uprates, for example, cost and pressure power uprates that are applicable if you have GE fuel.

Does the current fuel supply have topicals equivalent to those?

MS. BROWN: Not approved per se, but there are some guidance provided to the industry regarding mixed cores and other fuel types and where the staff does a validation of verification review which was conducted on Units 2 and 3 for the Framatone Areva fuels.

CHAIR BONACA: We have never seen it at the ACRS.

MS. BROWN: Not that I'm aware of.

CHAIR BONACA: It think it is a significant difference.

MS. BROWN: Yes, sir.

CHAIR BONACA: It would take time --

MR. McGINTY: I appreciate that. Again, throughout these discussions and I think it's led to part of why there's been some confusion thus far. While Eva is referring to our desire to in the future come before the ACRS and resolve all issues associated with 120 percent power uprates for all three units, that is not to say that there are not individual issues associated with each unit that need to be addressed. And so clarity in our communications throughout these proceedings, as well as on a daily basis between the staff and TVA are necessary in that regard.

CHAIR BONACA: I could see the possibility of a need for a TH Subcommittee to look at some of the calculations we have not seen before.

MS. BROWN: That is definitely one of the issues we have on the agenda for the March Subcommittee meeting is a discussion of the Units 2 and 3 fuel analysis and review.

DR. BANERJEE: I notice that you have on

the agenda the containment accident pressure.

MS. BROWN: Yes, sir.

DR. BANERJEE: That will be for 120 percent power level?

MS. BROWN: The discussion will range from -- will address the 105 as well as what's needed at 120 percent.

DR. BANERJEE: And you will also look at long-term pooling issues in this -- at this point, when you talk about containment pressure or only about containment pressure?

MS. BROWN: When you talk about long-term cooling, we're talking about suppression pool?

DR. BANERJEE: Yes.

MS. BROWN: I believe so.

DR. BANERJEE: Okay. Now you have nothing related to loss of coolant accident or small break LOCA.

MS. BROWN: That's integral in the containment over pressure review. The primary event that we look is the LOCA, but we also look at those special events as far as station blackout, ATWS and Appendix R.

DR. BANERJEE: Okay. Let's wait and see what you cover.

CHAIR BONACA: And realize again, the analyses were done at 120 percent.

DR. BANERJEE: Right, I realize that.

CHAIR BONACA: We will talk about that later.

MS. BROWN: Okay. With that, I believe that TVA will be making a presentation.

MR. BHATNAGAR: Good morning. My name is Ashok Bhatnagar. I'm the Senior Vice President of Nuclear Operations with TVA Nuclear.

My role currently is fully dedicated to the efforts at Browns Ferry since October of this year and is to safely integrate Unit 1 into the rest of the operating fleet with TVA.

I want to thank you for allowing us the opportunity to discuss some key topics with you associated with the Unit 1 Browns Ferry five percent uprate. I do appreciate the flexibility of the ACRS and meeting with us this month to address this issue.

Since the beginning, this project has been based on conservative decisionmaking and a commitment to having the time and resources to do this project correctly and I believe we have.

We've maintained and continue to maintain a methodical approach to completing the small amount or remaining physical work in the plant and complete the remaining robust testing program that has been on-going and is yet to come.

We're recovering this unit in a safe and reliable manner and with that, let me turn the presentation over to Bill Crouch who will give us an overview of what's been happening at Browns Ferry.

Thank you.

MR. CROUCH: Good morning. As I mentioned earlier, my name is Bill Crouch and I am the Site Licensing Manager at Browns Ferry and as Ashok said we appreciate the opportunity to come and talk to you today. We have brought a team of individuals with us here today. I'm not going to introduce all of them, but we have our Unit 1 Engineering Modifications Team. We have Fuels people here. We have our EPU managers here. We have GE Fuels people here. We have a complete team. So if you have a question about the Unit 1 five percent uprate, we're prepared to answer it for you today.

I'm going to give a little bit of an overview here, some background and history on Browns Ferry. Some of this, the bullets up here are a duplicate of what was in the NRC slides, so some of these I will pass over very quickly and others I'll spend a little bit more time to give you some background.

So with that, I'm on page I-3 of the presentation. It's about the third or fourth page into the presentation, in the booklet you've got there.

As you were told, Browns Ferry is a three unit plant with GE BWR-4s with Mark 1 containments in case any one is not familiar with what a Mark 1 containment is, that's the upside down lightbulb with the large torus around it that serves as a suppression pool. Coming off the torus, the ECCS systems take their suction from a ring header that goes around the bottom. So that gives you a physical geometry of the plant.

Unit 1, 2 and 3 were licensed in '73, '74 and '76. And after Unit 1 and 2 got licensed, we had the Browns Ferry fire which we recovered from in 1977 and began operating again. So a lot of people have confusion that this restart that we're working on for Browns Ferry Unit 1, we are not restarting from the fire. We had restarted and continued to operate for seven more years after that. So that's to give you some background.

Some things that we've done in the near

term is we have renewed all of our licenses for Units 1, 2 and 3 and there for an additional 20 years.

DR. CORRADINI: So just for the -- so that takes you through the 33, 34 and 36?

MR. CROUCH: That is correct. We've also recently done the alternate source term or AST that people refer to. That was done back in 2004.

Right now, we plan to return Unit 1 to service in early 2007. We're on track for doing that.

Next slide, please.

As we've gone through the Unit 1 restart, it's our intention to make Unit 1 operationally similar to Units 2 and 3. And the way we've done that is we set out to maintain the same licensing basis for all three units. As we restarted Unit 2, we, jointly with the NRC, created the plan, the Nuclear Performance Plan, and that gave us an outline of what all was going to have to be done in order to return the first unit to service.

We have utilized that same approach for returning Unit 1 to service, meaning that we had the same programs and performed the same modifications as we then performed on Units 2 and 3. So we kept the units to be the same.

Since the time of restart for Units 2 and

3, they have had various upgrades performed on them and so as part of our Unit 1 restart process, we performed those same upgrades, once again to keep the units the same.

As part of the Unit 1 restart, we also intended to go straight to the 120 percent. So in addition to performing the restart mods and the upgrades since restart on Units 2 and 3, we've also installed the modifications required for going to 120 percent. We are not here today asking for permission to go to 120 percent. We'll only go to 105 and we'll come back again as a separate request to go to the 120. The equipment will be in place to do that.

CHAIR BONACA: I am still -- this is more curiosity on my part. Why didn't you proceed with 120 percent power uprate request and then make a commitment to stop at 105 and operate at 105 with the provisions that you put in the RPS and other SER and so on.

MR. CROUCH: We will get to that a little bit later, but --

CHAIR BONACA: This is more curiosity.

MR. CROUCH: It was tied up with the steam dryers.

CHAIR BONACA: I understand that.

MR. CROUCH: Let me --

CHAIR BONACA: Okay.

MR. CROUCH: When we get down here in a minute, we'll talk about that.

CHAIR BONACA: One additional question I would like to ask you and you can answer whenever you want, one thing that comes to mind when I look at Unit 1, I went back to the documentation of record which is the updated FSAR and it's still the updated FSAR of 20 years ago, whatever.

MR. CROUCH: It's kept up to date.

CHAIR BONACA: I understand you do that. But assume some of the methodology used, of course, is the methodology used by GE at that time and now you're using say for GESTR and you know. So there are certain steps in transition that you normally do. For example, you realize all the base cases of originally you had in the last uprate with the new technology to compare the effects tied to the methodology you're using and separate them from the power uprate.

It wasn't clear to me that this has been done for this plant.

MR. CROUCH: The FSAR right now reflects 105 percent for Units 2 and 3. There's also information in there for Unit 1. It still reflects the old 100 percent. As part of this restart process, we will be updating the FSAR for Unit 1 to reflect it's new condition. There's also another FSAR update that will move the units to 120 percent.

CHAIR BONACA: I understand. I'm only saying that when you do that, you have to realize your latest analysis of record. When did you shut down the plant, 19 --

MR. CROUCH: 1985.

CHAIR BONACA: 1985. Don't you have to redo the analysis with the new methodology, okay, to determine the effect of the methodology on the results and then perform again the analysis of 120 percent power to determine the effect to do the power uprate?

MR. CROUCH: The comparison between 100 and 105, we did that when we did the Units 2 and 3 and showed what the impact was. And so we did not repeat that for Unit 1, because of the similarity of the units. And we have the analyses at 105 that were performed and now we got the analysis for 120.

CHAIR BONACA: Units 2 and 3 are licensed under Areva fuel so you have a different kind of basis there. I mean different analysis models, right?

MR. CROUCH: We have done the analysis for Units 2 and 3 for 105 which is what we did back in '98 and that was done with GE fuel and so we've got that comparison. GE, 100 percent; GE, 105. We have since done the analyses for Units 2 and 3 to compare the 105 Areva, on up to 120 Areva.

CHAIR BONACA: Okay, we need to understand that better when we get there.

MR. CROUCH: Okay, next slide, please.

Just to give you some idea of the overall scope of the Unit 1 project, these are some examples of the major work that's been performed. This is by no means an all-inclusive list. We've made major modifications in the dry well structural steel, the electrical penetrations, small bore piping, dry well coolers, cable and conduit.

We replaced all of the recirc RHR core spray, RBCCW and RWBCU piping inside the dry well. We replaced it from its original material to corrosion-resistant material. Kept the same geometries. It was just a material change.

DR. CORRADINI: This is a little bit of background. I apologize. So you've made it a point of saying that beyond the fire, you operated for seven years until '85 and then shut down?

MR. CROUCH: That's correct.

DR. CORRADINI: Can you remind us, a

little more history, as to why then in '85 you shut down Unit 1, but operated 2 and 3?

MR. CROUCH: Okay. We shut down all three units in '85. All -- the entire nuclear fleet, the entire TVA nuclear fleet was shut down in '85 because of management concerns and safety concerns in that we did not have an effective management structure to identify and resolve problems and we had not resolved various regulatory issues such as 790214 EQ, Appendix R and different things like that. So it was a combination of both management and technical issues.

DR. CORRADINI: And then 2 and 3 come back up and one didn't because?

MR. CROUCH: We just didn't need the power at the time.

DR. CORRADINI: Okay.

MR. CROUCH: We're now at the point where we need the power.

CHAIR BONACA: Would you say now in the changes you made in the piping, valves, etcetera of Unit 1, Unit 1, 2 and 3 are identical?

MR. CROUCH: From a geometric standpoint, they are identical. From an operational standpoint, they'd be identical.

CHAIR BONACA: From materials?

MR. CROUCH: From a materials standpoint, they're mostly identical. We did more piping replacement on Unit 1 than we did on 2 and 3. For example, in the recirc system on 2 and 3 we replaced what's called the ring header and the risers, but on Unit 1 we also replaced the large suction piping and discharge piping.

CHAIR BONACA: But is it the same material?

MR. CROUCH: The material we put in the ring header and risers on Units 2 and 3 is the same material we used throughout on Unit 1.

CHAIR BONACA: That's what I wanted to hear.

MR. CROUCH: So we've introduced no new materials on Unit 1.

CHAIR BONACA: So you can make the claim that --

DR. POWERS: Is that really true since they are different generations of what's nominally the same material, they really aren't the same, are they?

MR. CROUCH: Whatever may have changed. As a matter of fact, some of the piping we installed in Unit 1 was actually bought in 1985 in anticipation of doing this back that time ago. We've re-used it.

CHAIR BONACA: The reason for me is mostly flow accelerated corrosion, statements made in the SER that the experience of Unit 2 and 3 is applicable to Unit 1 and that's why I'm asking questions regarding materials and configurations.

MR. CROUCH: Robert would --

MR. PHILLIPS: My name is Robert Phillips and I'm with TVA and I'm their Senior Metallurgical Engineer.

We reviewed the materials for Units 2 and 3 and at that time we used 316 MG. Now for Unit 1, we used similar type materials. Now the CMTRs may not be identical, but the specifications are MG-type material. That's what we use.

MR. CROUCH: Okay.

DR. BANERJEE: You left some of the wiring in, didn't you?

MR. CROUCH: I will point that out. In the dry well, we replaced all the wiring.

DR. BANERJEE: Right, okay.

MR. CROUCH: In the reactor building, there was a small amount of a non-safety related wiring, but essentially all of the safety-related wiring was replaced.

DR. BANERJEE: But you left some of the

old cabling in place?

MR. CROUCH: Yes, it was abandoned in place.

CHAIR BONACA: But the fire analysis doesn't talk about that in the SER list.

MR. CROUCH: The cabling that was left in place is considered as part of the combustible material that's in the area.

DR. SIEBER: The loading, combustible loading?

MR. CROUCH: Yes.

CHAIR BONACA: That's 800,000 feet of cable. Do you have 800,000 feet of old cable left there?

MR. CROUCH: Dave, do we have 800,000 feet of abandoned cable?

CHAIR BONACA: Plus or minus 100,000.

(Laughter.)

I hate to be so specific.

MR. BURRELL: My name is Dave Burrell with TVA Unit 1 Restart. No, we didn't leave 800,000 feet of abandoned cable in place. We removed all of the cable out of the dry well. A goodly portion of that that was in reactor building was removed. All of the installed cable in the reactor building at post-fire recovery was coated with flamastic. That that's still under flamastic obviously remains.

CHAIR BONACA: So much of it was removed?

MR. BURRELL: That's correct.

DR. BANERJEE: What is flamastic?

MR. BURRELL: A material that we put on as a part of post-fire recovery to retard any flammability of the material. This would have been pre-IEEE 383 type cable and to minimize any combustibility for the cable we coated all the exposed areas with a material called flamastic.

CHAIR BONACA: Is this the cable that's left in right now, is it coated with this material or the exposed area coated with it?

MR. BURRELL: Yes. The old material is coated with the flamastic.

MR. CROUCH: Moving on to the reactor building, once again we give you some examples of things. We replaced the reactor building closed cooling water heat exchangers. These are heat exchanges that supply cooling water inside the reactor building. They're a heat exchanged that has raw water on one side and high quality on the other side. Rather than trying to retube the condensers or show that they were okay, we took the conservative approach and just completely replaced them.

Reactor water cleanup piping, we replaced all of that inside the reactor building. We also replaced the regen heat exchangers. We also completely replaced the RWCU pumps. We took a different approach on Unit 1 than what we did on 2 and 3 in that we went ahead and just took the conservative approach and replaced a lot of items out there in the building, rather than trying to do engineering analyses to show that they were okay.

So I'm not going to go through this whole list of all these things we've done. You can see there was major replacements done throughout the dry well, the reactor building and the turbine building.

We also did the -- in the control room, what's called the control room design review or the CRDR where we brought the control room up to the post-heat bystanders for human factors.

DR. SIEBER: I take it that we need not rely on any kind of a lay-up programs since you've replaced a lot of this equipment?

MR. CROUCH: We have replaced a major portion of the systems out there, but there are systems that were in lay-up and for those systems --

DR. SIEBER: That weren't replaced?

MR. CROUCH: That were not replaced.

DR. SIEBER: Could you give us a broad brush outline of which systems those were?

MR. CROUCH: The main steam system was not replaced. The feedwater system was not replaced. We performed both visual inspections and UT inspections of those systems and shown that there was no degradation through the lay-up process.

DR. SIEBER: How were they laid up, wet or dry?

MR. CROUCH: Those two systems were laid up dry.

DR. SIEBER: Was nitrogen in them?

MR. CROUCH: Probably. I don't remember for sure. In our guide, it had to acknowledge it.

Joe, do you remember? They didn't have nitrogen on them. They just had --

MR. VALENTE: Joe Valente from TVA. We laid them up with dehumidified air.

DR. SIEBER: Hot air. Okay. Silica gel or something like that?

MR. VALENTE: Yes.

CHAIR BONACA: I would like to point out for those systems you made commitments to periodic inspections under license renewal.

MR. CROUCH: Right, and we will get to that here later on.

Other systems that were water systems, some of them were laid up wet. Some of them were laid up dry. The biggest effect we saw and I'll get to that a little later on, in some of our raw water systems that were laid up wet, we saw a good performance and as long as it was laid up completely wet, there was no impact from the lay up. If you laid it up so that it was -- had some moisture in it with air pockets, you saw some severe degradation. All that type of system we replaced completely.

DR. SIEBER: How about biological growth? I presume you treated it for that, but I could picture a laid up system without circulation being a botanical garden.

MR. CROUCH: Yes, and we monitored that and we kept it in good condition.

DR. SIEBER: Okay.

DR. BANERJEE: What did you do with the sump screens?

MR. CROUCH: We don't have sump screens. We have the torus which has suction strainers and we replaced the suction strainers as part of the Bulletin 96-03. They're the large GE stacked disk strainers.

DR. BANERJEE: Stacked disk.

MR. CROUCH: Stacked disk.

DR. BANERJEE: And all of them are the same?

MR. CROUCH: Yes. We have the same suction strainers in all three units.

There's four large suction strainers in each torus. They're about four feet in diameter, four feet tall with the stacked disk design.

We also took a conservative approach in terms of flow accelerated corrosion in that we took lessons learned from Units 2 and 3 and places where we experienced pack degradation and we went over into Unit 1 and generically applied that experience to all the various piping systems such that if we were seeing degradation in one particular spot in Unit 2 or 3, but we had similar spots in Units 2 and 3 that weren't experiencing problems, we went over to Unit 1. We replaced all those conditions generically throughout the plant so as to prevent any future pack problems. We replaced it all with pack-resistant chromally piping.

Next slide, please.

Another conservative approach that we took on Unit 1 was we took and installed the same digital control systems as were installed on Units 2 and 3. We have digital systems on the electro-hydraulic control that controls the turbine, the feedwater control system, condensate demineralizers, the recirc pumps and the feedwater heaters.

DR. SIEBER: Is this a separate digital system for each of these applications?

MR. CROUCH: Yes.

DR. SIEBER: They're independent of one another?

MR. CROUCH: Yes.

DR. SIEBER: Okay.

CHAIR BONACA: These digital control systems also is installed on Units 2 and 3?

MR. CROUCH: Yes, these are all installed on Units 2 and 3.

CHAIR BONACA: So you have the experience?

MR. CROUCH: Yes.

CHAIR BONACA: Yes.

MR. CROUCH: Page 7 then. In addition to doing major modifications work where we replace stuff, we also went out in the plant and refurbished what was already out there. Some examples of that was the reactor core isolation cooling and the high pressure cooling injection systems. Those systems were in a poor state of repair when we started Unit 1. We've gone on and completely refurbished the entire skids, replaced valves as needed, whatever it required to bring the system back up to full tech spec operable status.

We rewound the main generator. We've gone out and we've replaced throughout the plant we've replaced many, many valves here. This gives you an idea of how many valves we replaced throughout the plant.

Instrumentation-wise, nearly all the instrumentation in the whole, throughout the whole plant has been replaced. The instruments that were sitting out there had corroded contacts and all the different problems you can imagine with instruments, so it's just all been replaced and will be recalibrated.

DR. SIEBER: Let me interrupt for a second. The numbers you showed here for valves that were replaced, looks like a big number, but there's probably about 17,000 valves in that plant, so there's a lot that weren't replaced.

MR. CROUCH: Right. For the valves that were not replaced, we've gone out and we've inspected each one of them, made sure they functioned.

DR. SIEBER: What about packing?

MR. CROUCH: That will have all been checked.

DR. SIEBER: How do you check it, with a --

MR. CROUCH: All the packing has been replaced.

DR. SIEBER: Okay, that's really the point. I started up a plant once that was shut down for a long time and every packing gland in the plant leaked. So just repacking them while you've got the chance and doing them all is probably economic. And that's what you're doing.

MR. CROUCH: That's what we're doing. Rather than trying to pencil whip stuff, we've taken the conservative approach to go do the maintenance on it or do the replacement on it.

DR. SIEBER: Okay. Your bill for umbrellas will go down.

MR. CROUCH: That's right. In-vessel work, we've done the -- replaced the control rod drives. It's not actually in-vessel. It's under vessel. We replaced all of the control blades. We replaced all of the LPRMs. We've also done the BWR-VIP inspections of the vessel internals.

Next slide, please.

Just to give you an idea of the scope, there's some numbers up there. As you can see, many, many feet of large bore and small bore piping. Many hangers have been replaced. Miles and miles of cable replaced throughout this project.

CHAIR BONACA: Let me ask you a question, however. In the context of the power uprate, you're talking about two large transient tests.

MR. CROUCH: That's correct.

CHAIR BONACA: Okay, but you're restarting this plant almost as a new plant, so you must have a full start-up program?

MR. CROUCH: Yes.

CHAIR BONACA: And you're probably testing system by system?

MR. CROUCH: Yes.

CHAIR BONACA: Before you do integral tests?

MR. CROUCH: Yes.

CHAIR BONACA: Okay. And how do you integrate this program and if there is no mention of it, perhaps we come into the power uprate tests and it seems to me as I was reading that you would have conducted this test of the 100 percent power anyway already.

MR. CROUCH: Yes.

CHAIR BONACA: Those two that you mentioned, loss of feedwater.

MR. CROUCH: No. Our restart test program which is driven by the nuclear performance plan I referred to earlier, it is a combination of component testing that you do as part of your post-modification, post-maintenance testing, accompanied with your surveillance testing, driven by tech specs, accompanied with special tests that were driven out of what's called our baseline test requirements documents. So we would have gone out and tested every safety function throughout the plant.

And so it's a combination of individual component tests and integrated full-system tests and then integrated-system tests.

The restart test program was not going to re-perform the low rejection or MSIV closure. Those tests were done back at initial licensing and it was our opinion at first that we would not re-perform those tests. However, through the discussions with the staff we're now going to redo those tests at the new 105 percent power.

CHAIR BONACA: So you don't have plans to have those?

MR. CROUCH: We did not initially plan to have them. We are now going to do them.

CHAIR BONACA: All right. Thank you.

MR. CROUCH: Next slide, please.

As Eva talked about, we initially submitted our continued power uprate for Unit 1 in 2004. That was going to go straight to 120 percent and we began installing the upgrades on Unit 1 to go to the 120 percent.

As we -- just about the time that we were making our initial submittals is when the problems with Quad-Cities started showing up and we started seeing these industry-wide issues. We initially were going to go forward with the 120 percent.

We created a scale model. We went and ran tests on for the steam dryers, collected data on the scale model, did analyses and were -- we were planning on using that as our verification for why it was acceptable to go to 120 percent. Through discussions with the NRC staff, it was decided that that was not a sufficient basis for it and that's why as Eva mentioned, we are backed up and taken the data, actual plant data for Browns Ferry on Unit 2.

DR. POWERS: You said you constructed a

scale model?

MR. CROUCH: Yes.

DR. POWERS: How do you scale it?

MR. CROUCH: It was scaled -- it's a 117 scale.

DR. POWERS: Why is that appropriate?

MR. CROUCH: Joe Valente, can you help us here?

MR. VALENTE: The question was why was a scale appropriate?

DR. POWERS: I mean how do you go about scaling something for phenomena you don't understand?

MR. VALENTE: It was geometrical scaling that was done based on parameters.

DR. POWERS: Why is that appropriate?

MR. VALENTE: Well, it had a lot of issues with the various scale factors approximate the actual conditions and staff in discussion with us essentially rejected it, based on those unknowns and subsequent review. We agree. It wasn't a satisfactory approach.

DR. CORRADINI: So are those results available in some fashion?

MR. VALENTE: The scale model approach?

DR. CORRADINI: Yes. We had some data.

MR. CROUCH: The scale model approach

results were all submitted.

MR. VALENTE: Yes. GE had some data and we did submit.

DR. BANERJEE: In the report?

MR. CROUCH: It was not being used as our basis, but it was submitted.

DR. CORRADINI: Thank you.

MR. CROUCH: So as a result of running in these questions on the steam dryer, as we were getting closer and closer to Unit 1 restart, we recognized that we would not be able to go collect the data and do the analysis for the 120 percent in time to support our proposed restart date. We decided instead to backup to the 105 percent.

We have operating experience on Units 2 and 3 that shows that the dryers are fully capable of withstanding 105 percent. So we made a separate submittal back in September to request to go to 105 percent, with the understanding that we would go and collect the data, actual plant data, do the analysis and resubmit that as our basis for going to 120 percent.

CHAIR BONACA: You keep talking about collect data and perform the analysis at 105 percent power.

MR. CROUCH: Right.

CHAIR BONACA: What we discussed before that actually what you have agreed to is to monitor power escalation all the way to 120 percent power, similar to what has been done.

MR. CROUCH: That's correct.

CHAIR BONACA: So that's not an analysis supporting 105 percent data. Your simply acceptance of the development of the monitoring program to monitor vibrations.

MR. CROUCH: What you do is you go and collect the data. We can talk about that more, but you strain gauges to collect the data off the steam lines.

CHAIR BONACA: At 105 percent power?

MR. CROUCH: At 105 percent power and using the strain gauges, you can convert the strain gauges data into pressure pulses inside the steam line which they use to calculate a loading that goes back to the steam dryer. At that point you do the analysis of the steam dryer at 105 percent and then you look at the results to make sure you've got sufficient margin to go on up to the next thermal-hydraulic point which would be 110 percent. You collect data again and redo the analysis at that point.

CHAIR BONACA: That is --

MR. CROUCH: That is a step-by-step process.

CHAIR BONACA: The analysis for the next step.

MR. CROUCH: That's right.

CHAIR BONACA: Not for the 110 -- all right.

DR. BANERJEE: I guess the hope is with all the patches and tie bars that you've added to these dryers that they'll hold up, right?

MR. CROUCH: That's the hope.

DR. BANERJEE: That's the hope.

MR. CROUCH: And we on Browns Ferry 2 and 3, we've seen just minor damage to the steam dryers. It has not been caused by the pressure fluctuations. The damage that we saw was due to a lifting problem we had. And so we've seen no indications of any problems at all at 105 percent.

DR. BANERJEE: Right, 105.

MR. CROUCH: Right. We have other plants out there that have also gone on up to 120 percent with no problems, so we will be doing it, not only the monitoring of the steam line stresses as we just talked about, but you'll also be doing monitoring for the moisture carryover, looking for that; looking for any pressure pulses in your steam lines. Those kinds of things would be indicative of the problem.

DR. BANERJEE: Do you have any strain gauges? You will speak to this tomorrow, won't you in detail?

MR. CROUCH: We can show you pictures of where we put the strain gauges.

DR. BANERJEE: Okay.

MR. CROUCH: It's better to wait for these detailed questions. We'll talk about that later.

Okay, next slide, please.

Page 10 there. As we talked about, we did make our EPU application based upon GE's extended power uprate licensing topical reports, the ELTR1 and 2. We also did a comparison to the review standard to make sure we've supplied all the information. If you look in our applications, since we are a pre-GDC plant, if you look at the review standard, quite frequently it refers to GDCs. So we supplied was like a road map to get from our application to the RS-001 format. You kind of have to go through a step-wise process, but we made sure we supplied all the information in the RS-001.

As we started out to make our submittal, we also went out and did an industry-wide search, looking for all the RAIs that have been submitted on any other plants' EPU applications and we addressed those explicitly in our application up front.

As we talked about some here, when we've made our 105 percent submittal, in some cases we utilized the analyses that were performed 420 percent, since they were bounding. However, we also recognize there are some places where the 120 percent analysis did not accurately or adequately reflect what would be operated at 105 percent. So in the area of the fuel analyses, we have backed up and re-performed the various analyses at 105 percent.

And one of the analyses that you referred to earlier, Dr. Bonaca, was a submittal that's due to you on January 31st and that is part of that fuel analysis that's coming. We're still on track for that, as far as I know.

Greg Storey? He says yes, we are.

CHAIR BONACA: That's the only analysis you've done on 105 is really the fuel.

MR. CROUCH: The fuel is the only analysis that was explicitly redone at 105.

Next slide, please.

Just to give you an idea that this is a

comparison of the current values at 100 percent versus 105 percent, obviously the thermal power goes up. Everything else pretty much scales up appropriately. We're using the same rod line on the power flow map is what we used before, so that results in the full power core flow range being reduced since you've simply gone up the same rod line to a higher power level.

As part of the application, we are also requesting a 30 psi increase in reactor dome pressure and that will put us at the same pressure as what Units 2 and 3 currently operate at.

MR. SIEBER: That takes you out of the constant pressure uprate topical --

MR. CROUCH: That's correct. For Unit 1, we could not use the CPPU process because it was not constant pressure.

MR. SIEBER: Okay.

DR. BANERJEE: Was it essential that you increased the pressure?

MR. CROUCH: It was essential on Unit 1 that we increased the pressure to make the Unit 1 operate like 2 and 3. You probably could have achieved the full 105 percent uprate without doing the pressure increase, but we didn't want to operate the two units separately or differently.

MR. SIEBER: There's less changes you have to make to the turbine point.

MR. CROUCH: That's correct.

MR. SIEBER: Now to go to 120 you would have had to -- you wouldn't do that, it would cause some pressure in there, right?

MR. CROUCH: From the 1050? Yes, it will be a constant pressure. It will stay at 1050.

MR. SIEBER: It will stay at 1050?

MR. CROUCH: Right.

MR. SIEBER: Oh, okay.

MR. CROUCH: And actually, when we took Units 2 and 3 from 100 to 105, we raised the pressure and did minor changes to the turbine nozzles. When we went from -- when we go from 105 to 120, we're replacing the high-pressure turbine and we'll talk about that here in a moment.

MR. SIEBER: But you haven't done that yet.

MR. CROUCH: On Unit 1 that has been done. It has not been operating yet though.

Next page.

A few more operating parameters there. Nothing of significant interest there on that page, other than as you refer to, the second line item there, the pressure at the upstream side of the turbine stock valve by raising the pressure like we did to 30 psi, and making the turbine control valves control the pressure at the same point, we were able to maintain the same unit pressure to the turbine.

Next slide, please.

To give you an idea of the modifications that we performed for EPU, as that slide I talked about earlier which showed many, many modifications going on, most of the modifications that performed the Unit 1 restart were not required for EPU. They were required for all these other programs, but here I'm going to talk about modifications that were explicitly required for EPU.

I'm going to start over on the left side of the page --

CHAIR BONACA: Please, before you move on, so that pages 11 and 12 really are specific to 105 percent parameters?

MR. CROUCH: They are specific to 105 percent.

CHAIR BONACA: One hundred five percent and you performed the analysis to support that?

MR. CROUCH: Yes.

CHAIR BONACA: Okay.

MR. CROUCH: So on page 13, starting over on the left side, with the reactor, which is shown in red. One of the first things we had to do was rerate the recirc pump motors. The core flow does not change, but we had to change the recirc drive flow just a little bit because of the increased pressure drop through the core, so the total core flow goes up a very small amount.

The recirc drive flow is very small amounts. We had to rerate the motors.

MR. SIEBER: How do you do that?

MR. CROUCH: It was --

MR. SIEBER: Does that require a bigger motor now?

(Laughter.)

MR. CROUCH: GE goes through and does an analysis of the motor and shows that you can drive it a little harder.

MR. SIEBER: All right. So you're going to have a greater temperature?

MR. CROUCH: Yes.

MR. SIEBER: And cooling load?

MR. CROUCH: How.

MR. SIEBER: How are those motors cooled? By air?

MR. CROUCH: They're water-cooled.

MR. SIEBER: Water-cooled. Okay. And that was taken into account in the analysis of adequacy of the cooling water and outlet temperature and all that?

MR. CROUCH: Yes.

MR. SIEBER: Okay.

MR. CROUCH: As we've talked about, on Unit 1, we have performed modifications to the steam dryers in anticipation of going to 120 percent. We have replaced the portions of the outer structure that was originally one half inch steel plate. We replaced it with one inch steel plate to make it more robust.

Moving on down the steam lines, the high-pressure turbine, as we talked about, we have replaced the high-pressure turbine rotating elements on Unit 1. So we get the additional energy out of the steam. So you can utilize the same inlet pressure and just change the pitch of the turbine blades and get the additional energy out.

MR. SIEBER: It's all reaction blading?

MR. CROUCH: Yes.

MR. SIEBER: Okay. Most of them are. They've been upgraded like this.

MR. CROUCH: Once the steam leaves the

high-pressure turbines, it goes through the moisture separators. We do not have moisture separator reheaters. We only have moisture separators. We've replaced the internal veins inside the moisture separator to remove a higher percentage of the moisture out. We were originally something like an 85 percent steam removal and we'll be up well above 90, after doing this.

DR. BANERJEE: Is it normal not to reheat in this after moisture separation?

MR. CROUCH: Our plant is not made with reheaters.

DR. BANERJEE: I know, but is it usual not to?

MR. CROUCH: I don't know what -- some plants have moisture separators on it. Some of them have moisture separators reheaters.

DR. BANERJEE: Just take it out.

MR. SIEBER: Usually, PWRs have moisture separator reheaters, some boilers do not.

I take it the pressure drop across that is greater than.

MR. CROUCH: I don't know if the pressure drop is --

MR. SIEBER: More blades to get more water out tells me more pressure drop.

MR. CROUCH: Might be.

DR. BANERJEE: You'll probably get more water at the low pressure end without the reheat.

MR. CROUCH: You would get more moisture than you would if you had a reheat, yes, but by changing internal blades, we removed it. I've forgotten the exact number. Somebody remember, it's something like 96 percent of the moisture or something like that. It's a real high percentage of moisture that we got out with this.

MR. SIEBER: You just have to look at it. I think in almost every turbine application, the last couple of rows of blades, you see drops of water.

MR. CROUCH: Okay, moving on down the main generator has been rewound to handle the increased electrical output. We've also replaced the main bank and the spare transformers out in the yard. That was not driven solely by power uprates, but was a combination of power uprate and just longevity of the transformers.

We've also increased the cooling in what's called the iso-phase bus that the duct coolers that cool the buses going out to the transformers, they were originally a single fan. We've now gone and replaced them with dual fans that are bigger, so not only have we increased the cooling capacity, we've also increased the reliability of it by doing that.

Once the water comes out of the hot well, we made major changes to the pumping systems sending the water back to the reactor. The condensate in the condensate booster pumps, we have upgraded them so that they -- the condensate booster and reactor feed pumps have all been upgraded such that we originally operated such that we have three trains of pumps and if we were to lose a single pump in one of those levels, condensate booster or feeds, we would have to reduce power.

We have gone and replaced pumps such that now, even after the loss of one of those pumps we'll still be able to operate at 100 percent power without any runbacks. So by doing this, we've added margin in the plant to prevent and power derates or any reactor trips.

We've also gone and added additional condensate demineralizers in to increase the clean-up capacity of the system. The feedwater heaters, we had to rerate the shell side on the number three heaters because of the additional pumping capacity. The pressure was higher than what the original shell was rated at, so we've gone and increased the shell pressure on that.

That kind of gives you an idea of the magnitude of the modifications that were done to support EPU. Obviously, there's also and I haven't shown on this page here, lots of set-point changes associated with the neutron monitoring and various systems out there. So we've taken all that into account as part of the Unit 1 restart modifications.

MR. SIEBER: Did you have to make any changes to the flow capacity of the reactor water clean-up system to make that function as -- with the same water quality as it would have at 100 percent power?

MR. CROUCH: We did not originally do that, but we have since gone and increased the RWCU capacity to help maintain the water clarity.

MR. SIEBER: It seems to me a lot of people would argue that you haven't changed the volume of the system any, so the capacity of the RWCU doesn't need to change, but you're putting more material into the reactor that can settle out there and so it just seems to me that you have to increase the capacity of the system to remove it.

MR. CROUCH: We have done that.

MR. SIEBER: You've done that. Okay.

MR. CROUCH: Yes.

MR. SIEBER: How effective was it during prior operation? Some plants it wasn't too good.

MR. CROUCH: Rich, can you help us with that some?

Rich is engineering manager and oversaw the work to go in and increase the RWCU flow.

MR. DeLONG: My name is Rich DeLong. I'm the Site Engineering Manager, Browns Ferry. We've actually completed the test in Unit 3 and Unit 3 is operating at the higher, almost double the recirc flow or RWCU flow.

We saw, immediately saw a couple tenths of a PPM decrease in sulfate concentration in the vessel. Not a whole lot of difference in any of the other constituents. They were just so low and the exit conditions from the demineralizers were already near pure water. So we haven't seen it. I think we'll see two things occur when we go to extended power uprate and that number one, we'll see, we'll be able to continue to maintain very low levels of sulfate concentration, those things. And our recovery from transients will be much better at that higher flow rate.

MR. SIEBER: Shorter.

MR. DeLONG: That's exactly right. We'll be able to get back inside our normal, what we consider our normal operating parameters of post-transient or following a start up much quicker than we currently do because the system in Unit 3 is performing very, very well at the increased flows.

On February 9th, we'll do the same testing we did in Unit 3 on Unit 2 and then subsequently raise its flow permanently on the back end of doing that test and upgrading our procedures.

We wanted to do this test on each unit because they do have small differences in the configuration of the clean up system, piping, etcetera, to make sure we didn't miss a particular operating parameter that was slightly different and change our philosophy for operating at those higher flows. We're pushing the system up there near its operating margins so we've got to be careful.

MR. SIEBER: Sounds like to me that your systems originally were working pretty well and taking steps to adjust the flow capacities to make them meet the new operative parameters.

MR. CROUCH: That's correct.

DR. BANERJEE: How are you monitoring the flows. Are they Venturis?

MR. CROUCH: How is RVC flow measured? Is it flow Venturi? They say yes, it's a flow Venturi.

DR. BANERJEE: A Venturi, and it's the same throughout this uprate?

MR. CROUCH: Yes.

DR. BANERJEE: And they're all the same, all the units?

MR. CROUCH: Yes. Any other questions on the EPU modifications?

DR. ABDEL-KHALIK: You indicated that you replaced the pumps, so that if you lose one out of three, you can still operate at 100 percent power?

MR. CROUCH: That is correct.

DR. ABDEL-KHALIK: That 100 percent, is that 120 percent?

MR. CROUCH: Yes.

DR. ABDEL-KHALIK: Okay.

CHAIR BONACA: This is an additional question regarding the EPU. In the spent fuel analysis, okay, now you need -- you show a couple of different configurations that you can use to cool and for example, one is one train each of spent fuel pool cooling system and ADHRS system.

MR. CROUCH: Right.

CHAIR BONACA: Is it the same configuration we had before the uprate?

MR. CROUCH: Yes.

CHAIR BONACA: Okay, so even before uprating, you needed tow pumps?

MR. CROUCH: Yes.

CHAIR BONACA: Okay, so you're not changing -- I'm trying to understand.

MR. CROUCH: The fuel pool cooling system itself is not -- the cooling function of fuel pool cooling is not a safety-related function, the safety-related cooling of the fuel pool is done by either RHR system or this ADHR system. It's also not safety-related.

CHAIR BONACA: But now you need one thing each?

I'm trying to understand about the reliability.

MR. CROUCH: Let us take that as a question. We'll get back to you on that.

CHAIR BONACA: Okay. I would like to have an answer before the meeting is over.

MR. CROUCH: Are we ready to move on? Slide 14.

Just to -- I want to talk, touch on a

couple of little small topics here that don't really fit into things in the future, so just to give you some idea as far as grid reliability. We did do studies of the grid reliability to make sure that once we, first of all, brought Unit 1 back on service and then also look at the fact that we were uprating all three units to make sure that our grid had the capacity and reliability to continue to meet its requirements. TVA is a little bit unique in that we both own the grid and operate the plant. So we can control everything to make sure that we're in compliance with the various FERC regulations and the various GDCs.

So we have done the studies that confirmed both the reliability and the capacity and we still continue to meet the GDC-17 requirements. We also have ensured that we meet our mega-VAr requirements. We will -- as we operate the plants, the low dispatchers require certain amounts of mega-VAr for the plant and we've shown that we have that capability to meet their requirements.

MR. SIEBER: I take it that probably some place on your system you have plants that major function is to supply VArs or heat VArs? Is Browns Ferry in that position at any time?

MR. TILL: I'm David Till. I'm the Transmission Planning Manager with TVA.

Browns Ferry is not in that position. We have only one fossil plant on our system that is really vital to VAr support.

MR. SIEBER: Okay. Now that you're up there --

(Laughter.)

I have one additional question. Usually, you calculate the voltage reduction to the safety systems in the plant if the unit trips. Now in the case of Browns Ferry, have you done that calculation to determine how far the voltage will dip at the plant if all three units trip from some common cause?

MR. TILL: Let me make sure I understand the question.

MR. SIEBER: Okay.

MR. TILL: If all three units trip --

MR. SIEBER: Right.

MR. TILL: The calculation as to what will be the effect inside the plant?

MR. SIEBER: As far as under-voltage is concerned.

MR. TILL: No, we have not. That's outside the scope of the off-site power calculations that we perform.

MR. SIEBER: Have you done it for one unit tripping?

MR. TILL: We have. We've done it for one and we've done it for one unit tripping with the other two off-line, the difference being that the system has already compensated before the last unit trips.

MR. SIEBER: You're going to have, depending on how you control your -- for all system generation, you would have a period of maybe 30 seconds where you're recovering. But that would be long enough to operate some of the trips, some other trips on the shift. I'm curious as to how far you got. I think the regulations don't require you to assume that everything goes back at once.

I just wondered if you had done that.

MR. TILL: We've not gone quite that far, no.

MR. SIEBER: Okay, thank you.

MR. TILL: Thank you.

MR. CROUCH: Any other questions on the grid?

Next slide, please.

As Eva talked about, when we were here back in previously for the license renewal application, when we applied for license renewal, due to the fact that we were applying for license renewal and EPU at the same time, in order to make sure that there was no confusion as to what was actually being approved for license renewal, we -- even though a lot of the license renewal evaluations were done at 120 percent, the license renewal application only applied to 100 percent power.

And so during the course of the conversations with you back at that time, as you kept asking questions, what is the impact of EPU on this license renewal and we kept saying we'll get to that later, well, this is now later.

And so we're going to talk about the impact of EPU license renewal. We've gone and looked at it from the standpoint of the operational changes. When you go to the EPU you obviously increase the reactor pressure. You've also increased pressure throughout various other systems. You've increased flow rates, temperatures, neutron fluence and radiation levels.

Also going to EPU, we've looked at it from the standpoint of what materials are out there, both the existing materials that were not replaced in Unit 1, as well as any new materials that were put into the plant.

As we went through these, we -- as we did each one of the modifications in Unit 1, our license renewal staff looked at the modifications, based upon the 120 percent conditions with the materials that were being installed, as we they went through the evaluated the impact on the license renewal.

So next slide, plese.

They factored the EPU impact into their various scoping and screening studies that were done, aging management reviews, aging management programs and the time limited aging analyses. In particular, there were four items here that were picked up as applying directly to the time limited aging analyses: the neutron embrittlement of the reactor vessels, the metal fatigue on the reactor vessel and internals, the EQ of electrical equipment, because of the increased radiation levels throughout the plant; and also primary containment fatigue.

As they did the evaluations, they concluded that obviously since they had done the evaluations at 120 percent that they found things to be acceptable.

Next slide, please.

In addition, another topic we want to take on is Appendix R and fire protection. The Browns Ferry Fire Protection Plan is a plan that's put together for all three units. We have performed modifications in Unit 1 to bring us into compliance with the NFPA codes. We replaced the sprinkler system and all the detector systems up to the code standards. We've also gone through and evaluated the plant for the Appendix R scenarios using the current methodology for how you evaluate fire loadings and the fire scenarios.

Coming out of that fire protection plan, we have the safe shutdown instructions. This is the plant procedures that proceduralize the manual operator actions that are required in order to respond to an Appendix R fire.

Obviously, as you bring a third unit into the operation, there will be additional actions in that there's actions over in Unit 1 that were not previously, but there are no new types of operator actions created as a result of bringing the third unit on line. If you had to go over into Units 2 or 3 and operate a certain breaker, when you go over in Unit 1, you're operating the same type of breaker over there. So no new types of manual actions were created when we went to Unit 1.

There's an on-going NRC inspection that will be coming in to look at our Appendix R manual operator actions. I believe it's going on right now. Next week, got moved a week. So that will be coming in and validating our actions to meet our procedures, to meet our fire protection report.

Next slide.

Unit differences. As we returned Unit 1 to service, as I said, we intended to do all the same modifications on Unit 1 as we previously performed for Units 2 and 3. However, in a few cases, we have intentionally installed some unit differences. In some cases, it was to eliminate unnecessary equipment. Other cases it was to address obsolescence.

The first one here on this sheet is the LPCI cooling injection cross tie valve. When the plant was originally configured, we have what was referred to as the LPCI loop selection logic which was an instrumentation system that was for the purposes of attempting to detect which of your recirc loops had broken and then to direct all of your RHR flow to the unbroken loop. Well, we later found out as several people in the industry did, that there is a potential single failure out there such that if this single failure occurred, you could be dumping all of your RHR out through your broken loop. So we removed LPCI loop selection logic back before we actually even operated it.

In order for that function to occur, there was a cross tie between the two RHR loops that had an isolation valve in it. As part of removing that loop selection logic, we went and closed that isolation valve. That line existed in all three units.

Well, the valve over the years has had a problem of leaking through. So it creates a maintenance headache. So as part of Unit 1 recovery, since we don't need the line anyway, since we removed the LPCI loop selection logic, rather than going and closing the valve and removing power from it, we just went and physically removed the line from the plant. So even though it is a physical difference in the plant, operationally there is no difference to the plant.

Another item that will be different in Unit 1 versus 2 and 3 is in the control room. We have installed the newer paperless recorders. As far as the operators are concerned, they'll still be getting the same information, they just won't have the rolls of paper to deal with.

The LPCI MG sets, the RHR pumps have LPCI

MG sets on them in Units 2 and 3 that continue to provide power to the MG sets in the event of the -- we have a loss of offsite power and we're swapping over to diesels. We have done the analysis for all three units and demonstrated that we do not need to have the LPCI MG sets because we reconfigured the electrical side of the plant now. We've installed that on Unit 1 and we've removed the LPCI MG sets. We have a project in place to go and do this same modifications on Unit 2 and 3, so we'll bring them back the same.

On Unit 1 for the low-pressure turbine, we've installed monoblock turbine rotors. This is a design that's put in place to eliminate the turbine blade cracking problem that we've had throughout the industry.

Hydrogen/oxygen analyzers, it's just slightly different on Units 2 and 3 in that it's a single train type system as opposed to dual trains. Same way with PAS. We've scoped it down based upon the newer regulations that have come out since we did Unit 2 and 3 restart.

As I mentioned also, obsolescence, we're replacing things. And what we talk about here is on some of our instrumentation, rather than having a brand X component, you can't buy a brand X any more, so we've now gone to a newer component. it does the same function. It's just a slightly brand name. It's got the same operating characteristics. We've done that on valves, different things like that where you cannot buy a particular component any more.

Once we get done with all of this, the units will be operationally similar. Obviously, things like LPCI cross tie valve, it doesn't affect the operation. The only difference would be is when Tony goes out to do his lot valve check list. He won't have to verify that valve is closed.

CHAIR BONACA: Will the procedures be identical?

MR. CROUCH: The procedures are identical with the exception of what's required to address these type of things.

CHAIR BONACA: I was talking about the emergency procedures.

MR. CROUCH: The emergency procedures are the same.

CHAIR BONACA: Yes.

MR. CROUCH: They're not the same document. We have procedures for each unit.

CHAIR BONACA: The reason why I'm asking is you have interchangeable crews, right?

MR. CROUCH: Interchangeable coolers?

CHAIR BONACA: No, crews.

MR. CROUCH: Crews, yes. We have crews that they're licensed for all three units and they rotate.

CHAIR BONACA: So I will expect that the list for the emergency planning procedures, you will have no differences?

MR. CROUCH: That's correct. Okay, next slide, I'm not going to go over these. Obviously, this is just a list of acronyms for you, as you look through our slides and hear our discussions. If you hear one of us refer to an ADHR or RHR or something like that, if you've got a question, here's the acronym for it.

MR. SIEBER: So look them up ourselves, right?

(Laughter.)

MR. CROUCH: You can look them up yourselves.

(Laughter.)

MR. CROUCH: Any further questions? Thank you. I'll turn it back.

MR. SIEBER: Thank you.

CHAIR BONACA: I would propose we take a

break now, rather than waiting until the end of the presentation. It's already 10:10. If that's okay, then we meet again at 10:30.

(Off the record.)

CHAIR BONACA: We are ready. So before we move into this presentation, I believe that Mr. Crouch a response to my question regarding the configurations for spent fuel pool cooling. I asked the question because in the SER they state that an increased power uprate, the licensee analyzed two configurations. In each one of the configurations, the licensee is using two pumps from different systems. I was asking whether this was true also before the power uprate to determine the reliability of the system. And I think I have a response to that.

MR. ELMS: My name is Tony Elms. I'm the Operations Manager at Browns Ferry. For 105 percent power in the current configuration on Unit 2 and Unit 3, fuel pool cooling is designed with two 100 percent capacity pumps and heat exchangers. The offload on the core, we control the amount of heat we put in the spent fuel pool by the rate that we offload the fuel.

We also have the augmented decay heat removal system which supplements fuel pool cooling and the procedural requirements as temperature rises in the fuel pool at 125 degrees, we have an additional system that's supplemental fuel pool cooling from the RHR system. So it would be placed in service also. So the temperature rises, we do have additional heat removal mechanisms that we can put in service.

We have had no problems at 105 percent maintaining spent fuel temperature.

Any other question?

Thank you.

CHAIR BONACA: The only other question I have in addition is this was true also before the power uprate, but what this shows me, for example, in configuration 2, where you're using spent fuel pool cooling and the RHR system, okay, probably you did not use both systems before the power uprate and now you may need both pumps to provide the same cooling, just because a higher heat load.

MR. ELMS: That is a possibility and those systems will be available if they are needed.

CHAIR BONACA: All right. Thank you.

All right, let's proceed with this presentation on plant systems.

MS. BROWN: Thank you. In this presentation, we will be discussing the balance of plant, fire protection and habitability, filtration and ventilation reviews. These areas are addressed in Sections 2.5 and 2.7 of the staff's safety evaluation.

Our approach in all the presentations is to focus our discussions on the more significant changes and process variables and EPU-related modifications. Unaffected or minor effects may be mentioned, but generally, it is our intent not to dwell on them.

The methodology using for operating a unit entails increasing reactor power along specified rod and flow lines. For balance of plant systems, this results in an increase in mainsteam and feedwater flow and an increase in reactor pressure.

For the Browns Ferry units, the pressure increases contained in the five percent review, along with the scaled main and feedwater increases. As discussed previously, there are certain review areas where the review conducted for the 120 percent bounded all aspects of the 105 percent and was applicable for all three units.

In the balance of plan area, this is true. For the power uprates, specifically, the Unit 1 105 percent review, the 120 percent review had been completed. For the 105 percent, the staff took another look to ensure that the information submitted completely bounded the 105.

Additionally, the technical review in these areas was also performed for Units 2 and 3 and found acceptable. Therefore, the information that follows is presented as staff's review for all three units at both power levels.

Staff's review found several areas which were minimally affected which, as we discussed earlier, means that these functions may not be power-dependent or the associated system changes do not significantly change or alter the performance requirements for these systems. So if we look like -- if we look in the area of internal hazards, we look at flooding. We have also looked at equipment and floor drains, the circulating water system and fire protection. We looked at component cooling water systems and we found this true for the ultimate heat sink, balance of plant systems, mainsteam, the main condenser and turbine steam bypass system, gaseous liquid and solid waste management systems as well. Some additional considerations like light load handlings and a diesel fuel oil and transfer systems.

In these areas there were more significant impacts seen such as internally generated missiles under internal hazards, or the turbine generator and pipe failures. For component cooling and decay heat removal, there are obvious impacts as you previously discussed with TVA on spent fuel pool cooling and the obvious modifications required to the condensate and feedwater systems to achieve 120 percent.

The staff's review found that consistent with a generic analysis, the existing design was adequate to bound power uprate effects in the area of internal hazards, fire protection, fission product control, waste management and most of the balance of plant systems. A more detailed review was required for the changes for spent fuel pool cooling and the condensate and feedwater pump modifications.

This slide really covers, I think what TVA just discussed, where we addressed the fact that of the increased heat in the spent fuel pool, so I think why don't we just go to the next one.

We're going to talk a little more about the administrative controls. To ensure adequate spent fuel pool cooling, the licensee has performed an analysis for the offload scenarios, each cycle prior to each offload to ensure that when core offload commences, the spent fuel pool temperature limits can be maintained, that the time to boil is known and adequate backup cooling capability is available.

In addition, the licensee indicated that the administrative controls will be used to ensure that the cooled temperature limit and time to boil will continue to satisfy licensing basis considerations and that backup cooling capability is provided for all spent fuel pool cooling scenarios.

These actions provide reasonable assurance that the available fuel pool cooling systems are adequate to support the increased decay heat as a result of power uprate.

For Units 2 and 3, the submittal includes a change to the original 95 degree limit. As Unit 1 was shut down, the temperature was never changed, but in support of the previous 5 percent power uprate for Units 2 and 3, the UHS temperature limit for the RHR service water system was decreased to 92.5 degrees in order to satisfy suppression pool temperature and containment performance considerations.

The EPU analysis restores the ultimate heat sink temperature limit for the RHR service water system to 95 degrees. As containment design limits will continue to be satisfied at the higher ultimate heat sink temperature limit for RHR service water during EPU operation, this change was found acceptable by the staff.

Modifications were made to the condensate, condensate booster pumps and motors and feedwater pumps and turbines to accommodate the increased flow required for EPU operation. The condensate feedwater system, as modified, should remain capable providing adequate flow at the EPU operating pressure and maintains sufficient margin so that a trip of one feedwater pump will not result in a reactor trip. Staff review confirmed that the analyses support these conclusions.

However, to confirm the transient response is as expected, the staff has imposed a license condition requiring performance of a single pump trip test. This testing will be required on Unit 1 at 105 percent and possibly at 120 percent while testing for Units 2 and 3 will be performed at 120.

For the balance of plant areas, in addition to this license condition, several commitments were made to better clarify existing processes. When we look at the -- given the information provided, supports the acceptance criteria and guidance outlined here, the NRC staff found that the balance of plant areas are acceptable, based on the evaluation results satisfying the acceptance criteria, given the completion of the license condition requiring single pump trip testing and the commitment to implement the provided procedure --

CHAIR BONACA: Would you go back to the previous slide? These are all the draft GDCs applicable to the plant systems that are in the licensing basis of Unit 1?

MS. BROWN: Yes, sir, in this portion on the review.

CHAIR BONACA: Okay.

MS. BROWN: And just for your information, Bill had indicated that they provided a crosswalk. It's in our February -- in their February 23, 2005 document is one of the enclosures. It's very useful for the staff to go from one requirement to the other.

CHAIR BONACA: This plant was not an SEP plant?

MS. BROWN: Not that we're aware of. That question came up before and I think the staff confirmed that it was not an SEP plant. We'll have to look that up.

Okay, do you want to move on to fire protection?

(Pause.)

Consistent with the extended power uprate licensing topical report, fire protection is one of those areas reviewed where no uprate effects are seen to result in the need for modification of fire protection systems such as suppression or detection or significant changes to fire-related programs including safe shutdown and other Appendix R-related operator actions.

As part of the Appendix R review, we find that the reactor and containment system responses such as peak fuel cladding, containment reactor temperature and pressure, as well as the integrity of fuel cladding, reactor vessel and containment while maintaining the existing exemption for momentary core uncovery during deep pressurization remain below acceptance limits at EPU conditions.

DR. BANERJEE: What is this exemption for the momentary core uncovery?

MS. BROWN: Ray, do you want to -- Bill, do you guys have your -- do you remember what that --

MR. CROUCH: Yes, we have an exemption that allows what's called a momentary core uncovery. The water level actually drops below the top of active fuel and then is recovered. It lasts a matter of just a few minutes. It's a standard exemption that nearly all BWRs have.

DR. BANERJEE: What causes this to happen?

MR. CROUCH: It's the depressurization. You go through and you blow down the reactor so you can get your low-pressure systems injecting and during that depressurization time is when you uncover the core for a short period of time.

DR. CORRADINI: Just to make sure I understand it, is it not that you essentially, the swell dies and then you reinject at a lower pressure or do I have that incorrect?

MR. CROUCH: It is not just the swell dropping. It is -- you blow down the reactor, so you're losing inventory.

DR. CORRADINI: And then how much -- you said for a matter of tens of seconds?

MR. CROUCH: It's on the order of minutes.

DR. CORRADINI: How much of the active fuel -- somebody had addressed this a couple of meetings ago, was it a matter of a couple of feet, a couple of inches?

MR. SIEBER: Seventy percent.

MR. CROUCH: Does anybody remember how much core gets uncovered?

DR. BANERJEE: This is quite substantial.

MR. SIEBER: Reactors are different, but you don't get complete uncoveries like down to the 70 percent level.

MR. CROUCH: You don't completely empty the reactor vessel, but I don't remember exactly how far down it goes.

DR. CORRADINI: Okay, thank you.

DR. BANERJEE: And this is usual for all BWRs?

MR. CROUCH: Yes, it's very common for BWRs.

DR. BANERJEE: And what happens when you go up 20 percent in part, how much heat up do you get?

MR. CROUCH: It's been analyzed that the peak clad temperature limits are still met.

DR. CORRADINI: Is it a function of power or is it a function of the depressurization?

MR. CROUCH: Both.

DR. CORRADINI: Both.

DR. BANERJEE: So when you say the peak clad temperature limits are met, how high does it get?

(Off the record comments.)

MR. CROUCH: It stays less than 1500 degrees.

CHAIR BONACA: Is this issue treated generically under the ELTR2 or ELTR1? No.

DR. BANERJEE: This is not treated

generically?

MR. SIEBER: No.

MS. BROWN: It's covered by the exemption that the staff issued.

DR. BANERJEE: But that exemption is a case-by-case exemption?

MS. BROWN: Yes, sir.

CHAIR BONACA: And has to be backed up by analysis. It has to be similarities of record that --

MR. CROUCH: That's correct.

CHAIR BONACA: Was this analysis re-performed now at the higher power level?

MR. CROUCH: Yes.

CHAIR BONACA: Okay.

DR. BANERJEE: And what tools were used for this analysis?

MR. DICK: This is Michael Dick with GE. They use the safe adjusted suite of codes.

DR. BANERJEE: And the analysis is contained in the -- in what? We've got it here, Ralph?

We don't have -- I haven't seen this analysis.

MR. CROUCH: The results would be in our submittals, yes, but you won't have the actual report.

MR. ANDRUKAT: It's discussed in the fire protection program, if you have a copy of that. There's a discussion with graphs that show the different power levels and core levels, etcetera, right in the fire protection program.

DR. BANERJEE: All right, carry on.

MS. BROWN: We also see in this area that adequate safety margin is maintained, even though the times available for some fire protection actions are reduced, such as the time available for operator, for an operator to the three main steam relief valves and the time available for an operator to secure a high-pressure cool injection prior to spurious actuation that would fill the reactor vessel.

CHAIR BONACA: You are telling us about the time. I mean how has it changed for the proposed rule?

MS. BROWN: Well, I think for the first one, I think we have on the slide that the open the main steam is reduced maybe five minutes.

CHAIR BONACA: Okay. Time available for operator to secure high-pressure coolant injection.

MS. BROWN: Yes.

CHAIR BONACA: Prior time is six minutes.

MS. BROWN: Yes, sir. And I think Bill

had mentioned previously that they have run validations of verifications of the operator actions.

CHAIR BONACA: That's right. How much is this reduced, high-power level? You're giving us a required time at six minutes. It's not that long. What was it originally before the proposed rule?

MR. CROUCH: On which one, the HPCI? On the HPCI, the analytical value at the 103 percent power was seven minutes, but we had the procedure at six minutes. When we go to the EPU, the analytical answer is six minutes and we've left the procedure at six minutes. So as far as the operator is concerned, there was no impact.

CHAIR BONACA: Okay.

MS. BROWN: Some of the process variables which changed in the Appendix R evaluation included changes in the analysis temperatures and pressures. Despite these changes, no hardware modifications were needed as a result.

As these process variables remain within the existing Appendix R limits, the acceptance criteria shown here has been met. So the staff found that the licensee adequately accounted for the effects of the increase decay heat, maintains the ability to achieve and maintain safe shutdown and therefore the fire protection program continues to meet its regulatory requirements.

Do we have any other questions on fire protection?

MR. SIEBER: This plant is an SEP plant, an Appendix R plant?

MS. BROWN: I don't know that it's an SEP plant. They are a pre-1979 plant, so they're not an Appendix R plant.

MR. SIEBER: Okay, that means from a separation standpoint you have to have barriers because the separation criteria were put in the regulations after the plant was designed, right?

MS. BROWN: Yes, sir. They do have the requirements for 3G and J and L by extension of G.

MR. SIEBER: The fire barriers, there's no thermal lag or any of that stuff in there, right?

MS. BROWN: I believe there is some thermal lag --

MR. BURRELL: There is some thermal lag.

MS. BROWN: The staff is looking at that.

MR. SIEBER: Where is it and what ratings do you consider it to be, if any?

MR. BURRELL: I'm Dave Burrell with TVA. As a part of recovering Unit 1, we are installing thermal lag on six circuits in the reactor building.

MR. SIEBER: You're doing that now?

MR. BURRELL: We're doing that as part of Unit 1 recovery.

MR. SIEBER: The thermal lag did not do well on testing, right?

MR. BURRELL: TVA has test-specific data that was performed for TVA and the thermal lag that's being provided is being certified to meet those testing requirements.

MR. SIEBER: Has the staff reviewed that application of thermal lag?

MS. BROWN: As part of the inspection, staff has looked at how the licensee installed the thermal lag.

MR. SIEBER: But the test report itself?

MS. BROWN: I'm not sure whether or not they've looked at the --

MR. BURRELL: That material was reviewed and test reports were reviewed and approved as part of the Sequoia and Watts Bar.

MR. SIEBER: I need to get some confirmation from the staff that they actually have looked at the application of this material as performing its fire protection function.

DR. BANERJEE: I just want to go back to that core uncovery part, if I may. The calculations were done with SAFER/GESTR, right? And the uncovery periods about 450 seconds and I guess you're just below the 1500 Fahrenheit limits, so what's the uncertainty on that?

MR. BURRELL: The temperature actually drops for the 120 case. It goes from 1485 to 1428.

DR. BANERJEE: It goes down?

MR. BURRELL: It goes down.

DR. BANERJEE: Why is that?

MR. BURRELL: I'll ask Fran.

MR. BOLGER: This is Fran Bolger from GE. The calculation was done with the SAFER methodology. The calculation is done as a nominal calculation without additional uncertainties. As far as what the differences of the calculation and why the water level differences and the PC differences, I haven't reviewed the calculation, so I can't comment on those reasons.

DR. BANERJEE: I guess we should look at these calculations because they're close enough to the limit, if I am understanding that.

We're talking about Appendix R. It's 1500. So we are close to the limit, so we need to take a look at it.

CHAIR BONACA: When are we going to get this information?

MS. BROWN: Do you want to see the report that the licensee submitted or the staff's review of that report?

DR. BANERJEE: Both. Report and the review.

CHAIR BONACA: We need both. So these are available?

MS. BROWN: I'll have to get back with you about that. I believe that the staff is reviewing the thermal lag by inspection. And as part of the inspection they would look at thermal lag and that inspection is happening next week. So I have to check and ensure that the --

CHAIR BONACA: I'm talking more about these analyses, SAFER/GESTR.

DR. BANERJEE: Oh, the SAFER/GESTR analysis.

DR. BANERJEE: As they say they've used nominal values, it might be perfectly fine, but we need to take a look at it.

MS. BROWN: All right, so you're looking for the SAFER/GESTR.

DR. BANERJEE: Yes.

CHAIR BONACA: The analysis and the review.

MS. BROWN: Okay.

MR. CROUCH: Hey, Eva.

MS. BROWN: Yes, sir.

MR. CROUCH: We should have the -- what we refer to as our task reports that provide the backup documentation for the PUSAR and so we ought to be able to pull out the analysis out of that for the Appendix R temperature analysis.

MS. BROWN: Okay, thank you.

MR. CROUCH: We can do that later today.

MS. BROWN: All right. We'll move to habitability, filtration and ventilation.

In Section 2.7 of the staff's safety evaluation, the staff discussed those habitability, filtration and ventilation systems listed here.

Using the acceptance criteria outlined in the draft general design criteria listed here, the staff reviewed the submittal to ensure that the ability of the systems to meet functional design requirements were normal and accident condition was maintained, given the capacity of these systems with respect to flow rates, pooling and filtration to perform as a result of the power increase, as well as to area heat temperature and electrical load changes.

The staff found that consistent with the generic evaluation provided in the EPU topical reports, the increase in power has no or little impact on a safety-related and nonsafety-related functions of these systems. Therefore, the staff concluded that there is sufficient capacity in the design of these systems to accommodate the proposed power increase and is therefore accepted.

CHAIR BONACA: So this conclusion is only applicable to 105 percent?

MS. BROWN: It is applicable to all units at up to 120 percent.

MR. SIEBER: That includes the effect of the increased source term?

MS. BROWN: Yes, sir. We'll talk a little bit more about source term tomorrow.

MR. SIEBER: All right.

MS. BROWN: That's what we have for plant systems. Did you want to roll right into the power ascension discussion?

CHAIR BONACA: That's -- yes.

(Pause.)

MS. BROWN: All right, for the power uprate test program, the acceptance criteria for review of the power uprate is provided in the following criteria: Appendix B, Criterion XI, the Standard Review Plan 14.2.1. Reg Guide 1.68 and Section 50.34 of the Code. The UFSAR Section 13.5 contains the plant-specific initial test program.

The staff's review is focused on ensuring that the power uprate test program includes testing sufficient to demonstrate that the system, structures and components will perform satisfactorily at the requested power level, given the extent of the original power ascension test program and modifications. It also recognizes that licensees may propose a completely different approach to testing with adequate justification. Supplemental guidance was provided in a standard review plan for staff evaluation of alternative approaches.

TVA did propose an alternative to integrated system testing. The staff's review of this proposal will be addressed later on.

Back in September 2005, as part of the license renewal briefing, TVA presented their proposed test program. The testing is conducted in four phases. Phase 1 deals with preoperational tests as discussed in SFAR Section 13.4. Phase 2 contains the fuel loading and shutdown power level tests. Phase 3 addresses the initial heat up to rate at temperature and pressure, while Phase 4 is essentially the testing and support of the power uprate.

For Unit 1, the licensee has indicated that Phase 1 contains the testing of the source and intermittent range monitors, integratedly testing of the containment and vessel hydrostatic testing.

Phase 2 looks at initial criticality and shutdown margin, high pressure injection systems, core thermal limits and calibrations of the average power and local power range monitors, plus scram time testing.

For Phase 3 which takes the Unit 1 to the old 100 percent power, it includes testing of the feedwater pumps, tuning system and runback test for the recirc pump variable drives and injection and tuning for the high pressure injection systems.

CHAIR BONACA: Wait a minute, these tests, these tests are their testing program or what?

MS. BROWN: This is what they're proposing for Unit 1 for the restart, just like you had indicated. This is for Unit 1 and as Bill had talked about looking at restart testing.

CHAIR BONACA: This is not discussed in the SER.

MS. BROWN: That's true.

MR. SIEBER: What kind of variable drive do they have on their recirc pumps?

MS. BROWN: Bill?

MR. SIEBER: This is the new drive system?

MR. CROUCH: This is the variable frequency drive system. It will be new for Unit 1, but it had been installed on Units 2 and 3 for several years now. Works fine. Works very good.

Greatly minimized our number of trips.

MR. SIEBER: Okay.

MS. BROWN: Now for Phase 4, the testing is performed at 2 to 5 percent increments. At each increment, the licensee intends to assess the core power distribution and performs testing of the pressure regulator, condensate/feedwater system and performs single pump testing. It verifies the vessel water level and rad level monitoring.

Additionally, there will be steam dryer monitoring similar to Vermont Yankee's test program with the exact increments and data submission requirements pending completion of the staff's steam dryer review.

MR. SIEBER: Could you refresh my memory as to what exactly is components of the Vermont Yankee dryer testing?

MS. BROWN: I do not think I have the right folks here for that because off the top of my head I wouldn't want to mislead you.

MR. SIEBER: I can look it up.

MS. BROWN: Bill, do your guys remember? I think we have someone in house that might remember that.

MR. SIEBER: Maybe someone from TVA can tell us what they plan to do.

MR. CROUCH: We have somebody that can address that.

MR. SIEBER: Okay.

MR. NICHOLS: Good morning. My name is Craig Nichols with GE. I was the TVA -- the VY Project Manager for their power uprate. For the steam dryer monitoring, the incremental power above 100 percent we required that every hour strain gauge data was taken and they would be held at 2.5 and 5 percent power increments. And at 5 percent increments that data would be submitted to the staff for their review.

MR. SIEBER: What were the strain gauges?

MR. NICHOLS: The strain gauges were installed on the main team lines in eight locations, two on each main steam line similar to what TVA has.

MR. SIEBER: Were you looking for vibration?

MR. NICHOLS: Looking for oscillating pressure within the main steam piping to develop a fluctuating pressure on the steam dryer.

MR. SIEBER: Hoop stress.

MR. NICHOLS: Correct.

MR. SIEBER: And what's the frequency and magnitude which you would consider unacceptable?

MR. NICHOLS: That's still being developed based on the exact same steam dryer design and the acoustic sources at the TVA plant.

MR. SIEBER: Now things could be happening in the dryer that would not reflect itself as a vibration in the steam line, right?

MR. NICHOLS: Actually, the work done to date with the various uprates have shown a very good, what's called coherence between what's seen on the strain gauges and what's seen on instrumented dryers, most recently the Quad Cities dryer. And that includes both acoustic loads and hydrodynamic loads.

MR. SIEBER: Okay.

DR. BANERJEE: Was that -- I don't recall that information of the Vermont Yankee discussions. Is that new information between the Quad Cities instrumented dryer and the steam line?

MR. NICHOLS: And I believe there will be discussions tomorrow and significant discussions on the steam dryer.

DR. BANERJEE: When you show us this data?

MR. NICHOLS: I'm not sure if that's within the presentation, but I'm sure questions could be answered on that.

MS. BROWN: I believe that we're going to have a very detailed discussion on that in March. That's one of the items that we want to make sure that we have all the information available to give you a full picture and story.

So we intend for that to be part of the March Subcommittee discussion.

DR. BANERJEE: And tomorrow?

MS. BROWN: Tomorrow, we're going to status where we are and address the status of the staff's review up to this point and our expectations for what the licensee is going to provide.

MR. SIEBER: Thank you.

MS. BROWN: As far as the power ascension testing, the staff reviewed this program to ensure that it included adequate system, component post mod, and component maintenance, as well as tech spec surveillance testing. As the Unit 1 restart and power ascension tests up to the old 100 percent are similar to tests conducted for the Unit 3 restart, the staff determined that integrated testing would be necessary to effectively confirm plant response and analysis. This concern will be addressed by Mr. Hamzehee next.

During the balance of plant discussion a license condition was imposed for transient testing of the condensate and feedwater system necessarily to confirm acceptability and consistency with analytical results.

As a result, the staff finds that the proposed test program, as supplemented by the staff imposed license conditions, meets the acceptance criteria and provides adequate assurance that affected systems, structures and components will perform satisfactorily in service.

And now Mr. Hamzehee will go over the staff's review of the licensee's proposal for large transient testing.

CHAIR BONACA: This is new stuff from the SER, so therefore, the SER you are discussing two measure transient tests, right?

MS. BROWN: The SER discusses the --

CHAIR BONACA: The license condition.

MS. BROWN: The MSIV. It discusses the load reject and it discusses the feedwater and condensate single pump testing which his what we're referring to.

CHAIR BONACA: Okay, that's what you're referring to?

MS. BROWN: Yes, sir.

CHAIR BONACA: All right, because I mean you're mixing, you started off with other tests and okay, so this is the one in which you are requiring individual pump --

MS. BROWN: Trip tests, yes, sir.

CHAIR BONACA: All right, that's the second bullet.

MS. BROWN: Yes, sir. Hussein?

MR. HAMZEHEE: Well, this is basically the results of the staff's review of the requirements for large transient testing which includes the MSIV closure test and main turbine generator load rejection test.

And the regulatory requirements are 10 CFR 50, Appendix A, general design criteria that talks about the requirements for SSCs that are important to safety that should be tested consistent with the quality standards and 10 CFR 50, Appendix B, Criterion

11 which is the test control and discusses the requirement for establishment of the test program to ensure that the required tests are identified and performed in accordance with test procedures. And also, 10 CFR 50.34 that talks about the plans for pre-operational testing and initial operations.

Next, please.

The staff's reviews are based on the four standards discussed here. It's the review standard for NRC Extended Power Uprate Review, RS-001; and also Section 14.2.1 of Reg. Guide 800 which is the generic guidelines for EPU testing program, part of the standard review plan. And we also have the GE topical report on generic guidelines for GE BWREPU, Appendix L; Reg. Guide 1.68 which is the requirements for initial test programs. These are the four standard reviews that we have used in our large transient testing.

Now basically justifications for not requiring large transient testing have been identified and discussed in 14.2.1, Section 3(C). And the highlights are summarized here which is basically the extent and nature of plant modifications, the setpoint changes, changes in plant operating parameters. Also, to ensure that the plant is in conformance with the limitations of the analytical methods so that if their is inadequate information, that does not really conform with the analytical method, then we may have to require the test, the large transient testing and also we have to look at the availability of relevant operating experience and also the risk considerations to make sure that number one, the risk associated with initiating a plant transient. On the other hand, benefits of having some of these plant problems identified during a controlled circumstance. So these are the -- some of the basic criteria used for the staff's review.

CHAIR BONACA: For determining.

MR. HAMZEHEE: Yes. And then now let's look at the justification for requiring large transient testing for Unit 1 at Browns Ferry. For Browns Ferry Unit 1, we require large transient testing mainly the MSIV closure test and main generator load rejection test. And these are consistent with the guidelines as discussed earlier of 14.2.1 of the SRP and the GE topical report.

And the main reasons for requiring the large transient testing is the fact that the plant has gone through extensive modifications and I don't believe I need to go over them this morning. You heard a list of all the changes, some of which were light refurbication of main feedwater, condensate pump, a lot of valves, booster pump, a lot of conduits, cable trays replacement and also the fact that the plant has been shut down for an extended period of time, I believe since 1985 and also there is not enough operating experience data to confirm some of the related operational experiences.

Any questions?

CHAIR BONACA: You are requiring these two tests?

MR. HAMZEHEE: Correct, for 105.

CHAIR BONACA: For 105.

MR. HAMZEHEE: Correct.

CHAIR BONACA: And the licensee had proposed to perform one of them at 120, 115 to 120.

MR. HAMZEHEE: That's correct.

CHAIR BONACA: Why you chose 105?

MR. TATUM: This is Jim Tatum, Balance of Plant Branch. We were pretty much following the guidance of the review standard and the onus was on the licensee to demonstrate any justification for taking exception to the testing that's specified in the review standard.

In considering the 105 situation, we felt that it was inappropriate to delay the testing because we don't know how long it's going to be sitting at 105 percent. So we essentially looked at this as two separate power uprate conditions, one going to 105 and establishing adequate assurance at that level, that the plant will respond as analyzed.

Now when they go to 120, they will have some operational data available, but still the onus will be on the licensee to adequately justify elimination of any testing at the 120 percent.

CHAIR BONACA: So you are leaving open the possibility of a testing at 120 still?

MR. TATUM: That's correct.

CHAIR BONACA: Based on operation at 105. I understand now.

DR. BANERJEE: It will get an automatic exception within the 15 percent or whatever it is. There's some --

CHAIR BONACA: Didn't sound like it.

DR. BANERJEE: They don't, right?

MR. TATUM: That's correct. Just strictly following the review standard, it would specify large transient testing unless the licensee is able to adequately justify the elimination of that testing. And part of the equation there is what sort of operating experience can they bring to bear for the staff's review. And one of the real shortcomings at least right now for Browns Ferry Unit 1 is the lack of operating experience. And they've just been shut down for so long, there's just nothing there for a plant-specific review of operating experience.

So we considered it very important to do the testing at 105 percent, especially recognizing that they could be sitting there at 105 percent for some extended period of time, but then when they go to 120 percent, we still have to consider the criteria in the review standard and the licensee will have to prepare sufficient information to justify not performing the testing and that remains to be seen.

Next.

Now for Unit 2 and 3, we are not requiring the large transient testing to be perform again, based on the criteria in 14.2.1 and the Appendix L of the topical report.

Again, based on the same justifications we discussed earlier for Units 2 and 3, there are enough operating experience information and data, and they have had some generator load reject in the past and they've had turbine trips, turbine stop and full valve closure events, so some of these things have already been experienced at Unit 2 and 3.

Also, a lot of changes are like Unit 1 that have been done recently and they have not been tested. The changes have been implemented throughout the last some years of the plant operation.

That should be it.

CHAIR BONACA: Okay, any other questions on that?

MS. BROWN: All right, then we want to move on to our generic risk presentation by Mr. Stutzke.

(Pause.)

CHAIR BONACA: Now this is a risk evaluation that is not referenced in the SER.

MS. BROWN: That's correct.

CHAIR BONACA: So what are you going to tell us?

This is a risk evaluation that is not even discussed in the SER.

DR. CORRADINI: Does that mean we have to travel to the plant.

MS. BROWN: They've already been to the plant.

(Laughter.)

CHAIR BONACA: What are we going to talk

about?

MR. STUTZKE: I will try to clarify this. Good morning. My name is Marty Stutzke. I'm a Senior Reliability Risk Analyst for PRA Licensing Branch A, Division of Risk Assessment, Office of Nuclear Reactor Regulation.

Before we get started, I'd like to recognize the contributions of my colleague, Steve Laur. At the time the original 120 percent EPUs came in, Steve was assigned to be the Unit 1 reviewer and I was the Units 2 and 3 reviewer. At about the time we got the request for the 105 percent uprate, Steve was promoted to Senior Level Advisor and as a result, I inherited all of the Unit 1 review work.

DR. CORRADINI: Congratulations.

MR. SIEBER: So why are you congratulating him?

(Laughter.)

MR. STUTZKE: As a risk analyst, the sequence is either successful or it's not.

This is the first of three presentations I've been asked to deliver to you, gentlemen. I find it amazing that you get to see me three times for the 105 percent discussions today and tomorrow, especially since this is a nonrisk-informed application.

DR. POWERS: Is it performance based?

(Laughter.)

MR. STUTZKE: The idea was this, that we knew that the Committee's composition and membership has changed and there will be Members here were unaware of how we look at the risk for nonrisk-informed applications. And so this morning I wanted to briefly explain how the staff goes through that process.

CHAIR BONACA: Before you do that or whenever, I'd like to understand when I go back to the record, I see that TVA has submitted a risk evaluation for the NPSH issue, that's a separate risk assessment.

MR. STUTZKE: That's correct.

CHAIR BONACA: That is not referenced in the SER, although the SER discusses NPSH issue at the 120 percent power.

I was puzzled that was not referenced or discussed in the SER.

MR. STUTZKE: I will try to explain that.

CHAIR BONACA: So you'll discuss that and you'll discuss also the -- you will answer the question, is there an overall PRA evaluations of the power uprate NPSH.

MR. STUTZKE: Now this afternoon when I

come back I will talk about the risk evaluation of the containment accident pressure credit.

CHAIR BONACA: Okay.

MR. STUTZKE: And then tomorrow afternoon, I'll talk about the other insights from the risk assessment, not related to the credit.

Let's flip to Slide 3, please.

As Mr. Sieber noted, power uprate requests are not risk-informed submittals. In other words, they're not submitted in accordance with Regulatory Guide 1.174. Staff has a process whenever we receive any requests for license amendment, a project manager reviews it to NRR Office Instruction LIP101 to decide whether there are risk implications going on here.

When we get a nonrisk-informed application, then the staff starts to think about Standard Review Plan Chapter 19, Appendix D. That's the guidance to the staff on how to consider risk information from nonrisk-informed applications.

The basis or the concept behind that appendix is a use of risk evaluation techniques to consider adequate protection. There's a presumption that if licensees comply with regulations and other requirements that adequate protections exist, like this. So the purpose of the risk evaluation then is to act almost like a spoiler. We will try to find if there are things in that application, be it non-risk informed that would give rise to questions of adequate protection in this.

DR. CORRADINI: Can you say that one more time? I'm trying to understand.

MR. STUTZKE: It is confusing. The presumption is adequate protection exists.

DR. CORRADINI: Because?

MR. STUTZKE: Compliance with regulation.

DR. CORRADINI: With the deterministic rules so --

MR. STUTZKE: Right. But there may arise, we call them special circumstances, situations where even though compliance with regulation can be demonstrated, we still may be concerned about undue risk.

MR. RUBEN: This is Mark Ruben from the staff. I can give you a 20 second history of where this came from. There was an issue of about five years ago that involved retubing of the steam generator, excuse me, sleeving repair of some degraded tubes. And at that time, the steam generator repair met all the deterministic design basis accident requirements.

However, the severe accident response of the repaired tubes was somewhat less than the original tubes. So the issue arose of well, it meets the regulation of -- it meets the design basis accidents, how do we consider the fact that there may be some nondesign-basis severe accident impact that should be brought into NRR's decisionmaking process.

Senior office management felt that there was a gap in guidance to tell the staff how to do that and they directed the staff to develop some procedures and guidance that were sent to the Commission. Basically, the -- as Mr. Stutzke said, the presumption is the plans are adequately safe. They meet all the regulations, yet those regulations are based upon evaluations of plant to design-basis accidents as defined in Chapter 15.

As we all know, the risk to the plants don't come from design basis accidents, they come from far beyond, in the severe accident space and the staff was just given direction and authority by the Commission in those rare instances and I want to emphasize the word rare because we really haven't run across them where the plant may meet all the regulatory requirements, for design basis, but there may be a degradation in the severe accident, severe response realm that should be considered by the staff and senior management in making its ultimate decision.

And the guidance that was endorsed by the Commission gives the staff the authority to seek, attempt to seek risk information in those situations where they believe adequate protection is not maintained, even though all the regulatory requirements are met.

The Commission felt this would be such an infrequent occurrence that if it is ever identified and the staff implements the procedures to the point of perhaps disallowing a licensee action based on this provision, we are required to notify the Commission and that has not occurred up to this point.

DR. CORRADINI: Thank you. The translation is good engineering judgment requires that you look at everything.

MR. RUBEN: Right.

MR. STUTZKE: Moving to slide four, because the submittal is not risk-informed, the burden then falls to the staff to demonstrate the presumption of adequate protection that's not being supported. And we have some guidance that defines so-called special circumstances that tell us when we may have a problem here.

Moving on to slide five, examples of special circumstances are listed here: increasing the likelihood of consequences of accidents that are beyond the design basis; degrading multiple levels of defense or reactor oversight process cornerstones; significant degrading and availability or reliability of equipment; or synergistic or cumulative effects, specifically power uprates were identified.

I would point out that part of the debate over the credit for containment accident pressure is a degradation of multiple levels of defense-in-depth. That's the concern.

So once we suspect that special circumstances may exist, we can complete an evaluation as shown on slide six. We do it by considering five key principles of risk-informed decisionmaking listed in Reg. Guide 1.174, compliance with regulation, consistency with defense-in-depth philosophy, adequate safety margin; small risk increases and we need to monitor for the impact of the change.

Now my job as the reviewer is primarily number four, the other items are the more traditional cognizant branches of these things.

That being said, we have to be mindful that the numerical risk acceptance guidelines in the

Reg. Guide, what I refer to them as XY plots with baseline CDF and delta CDF and similarly with LERF and delta LERF, those guidelines don't define what we mean by adequate protection. That's a more broader term. In other words, we're not risk-based, but we're risk-informed like this.

Continuing on, slide seven, SRP 19 does give us some guidance on when, how to look at the defense-in-depth issues. Significant increases, challenges to barrier integrity or changes to barrier failure probabilities, introduction of new or additional failure dependencies among barriers. Again, that's the issue about the containment accident pressure. Overall redundancy and diversity among barriers may not be sufficient for -- to meet the guidelines.

So this is the basis for deciding whether defense-in-depth that's been preserved.

DR. KRESS: The word "significantly" shows up a lot in there.

MR. STUTZKE: Yes, sir.

(Laughter.)

DR. KRESS: Do you want to tell us a little bit more about that or --

MR. STUTZKE: We have no specific guidance beyond this as to what is a significant increase, for example, in the likelihood of failure. I think it comes down to a judgment call.

DR. KRESS: Judgment call.

MR. STUTZKE: But it does admit there could be some increase.

Similarly, we have some guidance on safety margins as shown in slide eight, meeting established engineering codes and standards and meeting the acceptance criteria of the licensing basis. It's rather cut and dried.

Okay, with respect to changes in risk on slide nine, the EPU review standard prepared by NRR indicates that the focus should be on the base risk, total CDF, total LERF, no vulnerabilities for margins-type analyses, as opposed to the delta, the change in risk evaluation. That's where you see a big difference in Reg. Guide 1.174 where we -- I won't say we fixate on the change in risk, but that's a major part of it.

We look at EPUs specifically the baseline risk and the whole package is what's important, like this. However, if the base risk or the change in risk would exceed the Reg. Guide 1.174 guidelines, then we would have to investigate further and proceed with a more integrated decision process to decide if we've actually identified the question of adequate protection at this point in time.

Okay, so what happened on Browns Ferry review, other than I suddenly inherited a lot more work? The licensee did not provide a risk evaluation of the interim 105 percent power uprate, nor does the staff routinely look at the risk of proposed non-EPU power uprates. So anything below about seven percent, the PRA folks don't normally even look at the license request.

I've been unable to identify any case where that's not true. We tend to fixate only on extended power uprates big ones like this.

However, we did notice that in order to get the 105 interim power uprate, there was a request for crediting containment accident pressure for NPSH to the BCCS pump suctions.

DR. CORRADINI: Can you say that a different way? I interpret that to mean that the fact the containment has a higher pressure that helps their NPSH, do I have that correct?

MR. STUTZKE: Right. Briefly, the idea is --

DR. BANERJEE: They are requesting credit for it.

MR. STUTZKE: I'm sorry?

DR. BANERJEE: They're requesting credit for it.

MR. STUTZKE: Right.

MR. SIEBER: And NPSH is needed. The pumps need that extra help. Pumps won't function properly without the extra pressure.

DR. CORRADINI: Made by the containment pressurization.

MR. SIEBER: Right.

MR. STUTZKE: We will discuss this in, I imagine --

DR. CORRADINI: If it's later, it's later. That's fine.

MR. STUTZKE: Detailed this afternoon.

DR. CORRADINI: Fine.

MR. STUTZKE: But the concern then from the risk perspective is because the pumps need to be containment accident pressured to prevent their cavitation, it could be perceived as introducing a dependency now between the various barriers.

DR. CORRADINI: Can I say it differently? So if I have better heat transfer than I expect in containment, I have a problem? Is that another way of saying it.

MR. STUTZKE: That's another way of saying it.

DR. CORRADINI: Thank you.

MR. STUTZKE: Or alternatively, if the containment loses its integrity, they have a problem. So a containment failure is now inducing core damage from a risk perspective.

MR. SIEBER: Causing a fuel barrier failure

MR. STUTZKE: Right, and that's the concern.

DR. CORRADINI: Thank you.

DR. BANERJEE: We have faced this concern before.

MR. STUTZKE: Yes. Most recently at Vermont Yankee.

DR. BANERJEE: Right.

DR. POWERS: Surely not.

(Laughter.)

MR. STUTZKE: So anyway, the idea was because they needed containment accident pressure, both for the 105 percent interim uprate as well as the 120 percent extended power uprate, we tended to fixate or focus on the 120 percent power uprate. And so all of the risk evaluations of the containment accident pressure credit were based on 120 percent. I can give you a little reason why the answer is not sensitive to the power level.

When we did this in PRA space, the focus will be looking at how one can lose integrity of the containment either through some unidentified pre-existing leak or perhaps a failure of containment isolation, something like this. And accident sequences are developed accordingly. The actual power level doesn't have that strong of an impact. In other words, we assume once the containment integrity is lost, that the containment accident pressure probably is not going to be there.

Now there are some -- we'll talk later this afternoon --

DR. BANERJEE: Don't you need more credit, I mean a higher pressure for higher power?

MR. STUTZKE: Apparently not.

DR. BANERJEE: Why?

MR. STUTZKE: Well, when they do the calculation, they will, in essence, they are back calculating the required containment accident pressure to prevent cavitation and that's compared to a thermal-hydraulic calculation of the actual containment pressure they expect to see.

DR. CORRADINI: But the -- I apologize. I'm new to this. The inference is then stored energy is not a function of power? And I at least to a first approximation, it ought to be some function of power?

MR. RUBEN: This is Mark Ruben. One of the driving forces, of course, is the pump characteristics and what it requires. As part of power uprate they needed increased ECCS flow, and as a consequence we're in a different point on the pump head flow curve, then it would be a function of power uprate. But if you don't have to change the flow of the pump, then it's just the normal head requirements for that flow rate.

DR. BANERJEE: What about the temperature of the water? If you're going up in pressure to uprate the plant, does that change?

DR. KRESS: That's the pressure pool temperature.

DR. BANERJEE: That's what I mean, yes.

MR. STUTZKE: I would suggest we defer this to this afternoon's discussion.

CHAIR BONACA: But did they perform the analysis at the 105 percent power?

MR. CROUCH: We are going to talk about

all of this as part of J.D.'s presentation.

MS. BROWN: Yes, licensing goal in some detail.

MR. STUTZKE: So that's what I have to tell you for this morning.

DR. KRESS: In your consideration, 1.174, I like your comment that adequate protection just doesn't mean CDF and LRF. It also means all the other things. But does it also mean releases and LRF, for example, late containment failures. Is that part of your look at the risk?

MR. STUTZKE: No, it's not. We tend to look only at the risk metrics, CDF and LERF. Large early release frequency.

MR. RUBEN: This is Mark Ruben again. Those were certainly the primary metrics, but the two or three vu-graphs that Mr. Stutzke went over is the initial quick screen to be able to dispel the concern of adequate protection.

If we don't meet the quick screen, virtually everyone has always met it. You start getting into a lot more complex issues and phenomenon. One of those could very well be long-term containment integrity with respect to adequate protection. So I would rule out it would be part of the full decision process. It's just not one of the quick screen metrics.

DR. POWERS: The licensee has a history of fire events at one of his plants, has gone to some lengths to explain that he has upgraded his fire protection plan and fire protection capabilities to reach various NFPA standards and what not. He is, of course, acutely aware of Appendix R.

Can you explain how you go through and review the fire risk significance of the changes that were made in this plant?

MR. STUTZKE: The review of an external event such as fire for this plant is basically a margins-type of an approach. In other words, there's no quantitative fire risk assessment performed. Rather, it's a looking for vulnerability from room to room, like this.

What that means is that they do what is called area screening, so they systematically look at every compartment, every room, every fire zone and ask what would happen if all the equipment in the room was damaged, was rendered ineffective? And going through that sort of process they can quickly zoom in on the rooms where things are vulnerable like that.

However, the estimate --

DR. POWERS: It's all very remarkable because the particular event that is of such historical significance at this set of plants involved a fire started in one room that propagated to another room. And so it's remarkable to go room by room and not take advantage of the more integrated view that a risk assessment offers.

MR. STUTZKE: There is consideration when one does this analysis of the propagation from room to room. One does begin to look at combinations of rooms, different types of scenarios like that.

But the idea of the screening then is done on a frequency of how likely are things. And typically, scenarios that are 10^{-6} or so per year are screened out from further consideration in the analysis.

DR. POWERS: Again, this is all very remarkable because it seems to fly in the face of the protestations made by the Commission that they want to move to risk which would be looking at the product of the frequency and the consequences, as rather just a frequency itself.

MR. STUTZKE: Well, I would argument whenever one looks at risk metrics such as core damage frequency or large early release frequency, one is focusing only on the frequency aspect, not the consequence like this.

DR. POWERS: And I would agree with you explicitly and again say it seems to fly in the face of the protestations made by the Commission that they're looking at risk, when in fact, they're not. They're looking at frequency.

MR. RUBEN: Dr. Powers, your point is obviously a very good one. About all we can say to put the approach into perspective is that many, I guess I could say, most plants do not have full fire PRAs at this time. In fact, the developing standards for fire PRA do allow simplified methodologies such as five or modified versions of it.

DR. POWERS: The question is, of course, whether it's simplified or simplistic.

MR. RUBEN: Yes, sir. But again, there is no specific requirement for a PRA-based criteria to be met as part of EPU. The issues you raise that are very significant would essentially be almost the same pre- and post-EPU, except for some small timing changes of decay heat and the time you had available to respond to a fire initiator. But your point is a very good one.

DR. POWERS: But it seems to me that if

they're not specific requirements, in order to assure that we're providing adequate protection, then under Section D, the staff ought to be leaning forward in the trenches looking at the real fire risk associated with any plant changes and ought to have the tools to do so.

MR. RUBEN: At the current time, we don't have a regulatory vehicle to insist on fire PRA to be done, except in those cases if I can refer you to the phase PRA quality initiative, except in those cases when a licensee comes and voluntarily with a risk-informed initiative, where the fire contributors due to the change that the licensee is requesting, is a significant contributor due to the change, and that does not appear to be the case here. And in fact, this is not a risk-informed submittal. So I certainly can argue your technical merits. They have a lot of validity, but with respect to this particular implementation, the plant fire risk is what it is. They chose not to do a full fire PRA. That's correct.

Marty?

MR. STUTZKE: That's correct.

MR. RUBEN: And so we have best simplified methods which the industry has -- the majority of the industry has used and in fact the standards allow them to continue to be used with some limitations in Reg. Guide 1.200, depending on the application.

DR. POWERS: But nothing you said constrains the staff to use those simplified or perhaps simplistic methods, does it? What you're constrained right now is by the tools that you have available.

MR. RUBEN: If we, in the course of our evaluation, identify what we think is an issue of adequate protection due to the power uprate, with respect to fire, then we would pursue it as best we could with whatever tools we had available, which would likely be the simplified methods at this time.

If the simplified methods fall short of providing the type of confidence we need, then as a decision analyst you're forced to err on the side of conservatism in your decisionmaking, based on the uncertainty and the limitations of knowledge.

DR. POWERS: I would hope in the course of your review, you identified a vulnerability to anything, whether it was associated with a power uprate or not, you would pursue it.

MR. RUBEN: I'm certain the people responsible for that particular error would pursue it and we would identify it for them. The ability to calculate the exact contribution is the issue I was speaking to.

DR. POWERS: Let me inject that I have no reason to think that there is any vulnerability for this plant. This is a more generic issue.

MR. RUBEN: I share your concern, as a matter of fact.

DR. POWERS: I know you do, and we'll get to chew on this a little more in the future, I'm sure.

DR. KRESS: It seems like a good issue for the technology-neutral framework. We want to make sure we address that issue there.

CHAIR BONACA: But just looking at your last slide, I mean you said that the evaluation done at the 120 percent power will be similar to what you would get in 105 percent. And yet, you're still supporting the perspective that you do not need risk evaluation for below seven percent power uprates? I mean, the experience seems to show now that you should even for those.

MR. STUTZKE: Actually, the experience shows that for all of the extended power uprates, we've done a look at the risk evaluation. We've never identified a special circumstance. In fact, the core damage frequencies don't seem to change very much as the result of power uprate either extended and by extrapolation then for less than an extended uprate, you wouldn't expect the risk to change very much either as measured by core-damage frequency or large early-release frequency.

DR. CORRADINI: So whether it be CDF or LERF for extended power uprates, you don't see a big effect?

MR. STUTZKE: Not on CDF or LERF.

MR. SIEBER: There's a couple of issues there. One of them is you don't measure the decrease of margin. Second one is risked people does increase with the power uprate because the source term goes up.

MR. STUTZKE: Certainly the risk goes up.

MR. SIEBER: So we're using the wrong surrogates to measure this.

MR. RUBEN: But if --

DR. KRESS: Am I supposed to say amen here?

MR. SIEBER: You can if you want. I read your 100 white paper.

(Laughter.)

DR. KRESS: One hundredth of the same subject.

MR. RUBEN: This is Mark Ruben again.

There was -- you're absolutely right on the direct impact on a "pure calculation of risk". The source term MANRAM is essentially linear on power uprate. There was a study done by the Swiss, I believe, and we talked about it with the Committee about three years ago. Very interesting study. But the approach that the staff uses in its decisionmaking, lacking as Dr. Kress has pointed out on a number of occasions, is that a LERF is a LERF. It is a large enough release to cause, have the potential to cause early fatalities before effective evacuation can be put into place.

If we were to use a different metric, that means we would evaluate a plant like Oyster Creek much differently than we would evaluate a plant like Grand Gulf. But we don't, and when we came to the Committee with the risk-informed regulatory initiatives and the decision metrics and the risk-surrogate metrics, it was thought that they should based on per unit risk, not be scaled for power and not be adjusted for number of units on site, though that issue is being given very vigorous attention on the new reactor, part 53 rule development

MR. SIEBER: I think we will give commensurate attention to that also.

CHAIR BONACA: Okay, so we're anxiously

waiting for these presentations in the afternoon. We got to the end of our morning. We're well ahead of time, but we cannot start before scheduled time, because I think that's a problem. So we have to have a long lunch. For those of you who smoke, you can have a long cigar. Outside. So we'll now take a recess until 1:40.

(Whereupon, at 11:53 a.m., the meeting was recessed, to reconvene at 1:40 p.m.)

A F T E R N O O N   S E S S I O N

1:42 P.M.

CHAIR BONACA: Okay, let's get back into session and I believe the next presentation is going to have to do with the containment of the pressure.

Before we do that, however, there was a question from you this morning regarding LOCA.

DR. BANERJEE: Right.

CHAIR BONACA: And I think that TVA is ready to provide some information?

DR. BANERJEE: Appendix R.

MR. CROUCH: Fran Bolger from GE is going to answer the question.

MR. BOLGER: This is Fran Bolger from GE. There was a question regarding what caused the decrease in the PCT in the Appendix R calculation and to clarify the calculation that was done at 105 used the ANS 5.1 1979 decay heat. The calculation that supported the 105 had a very sparse set of data points in the decay heat curve and because of that, the decay heat assumed, at the point of the maximum PCT was very conservative.

That calculation was redone at 105 percent power with the PCT of 1323. The EPU-calculated PCT is for the same fuel type G13 was 1412. So then there was -- so there is actually approximately a 90 degree increase in PCT due to power uprate.

DR. BANERJEE: So the original calculation shown was something like 1480 or something?

MR. BOLGER: 1485.

DR. BANERJEE: 1485. That was just due to the fact that very conservative decay heat hadn't been taken?

MR. BOLGER: That's correct.

DR. CORRADINI: Using the ANS decay heat standard?

MR. BOLGER: Yes, but the table -- the decay heat table had very sparse set of number of points and you know, it's important to have a lot of detail in the decay heat points in order to get an accurate representation of decay heat and time.

DR. CORRADINI: Early in time, particularly.

MR. BOLGER: Yes, that's correct.

DR. BANERJEE: Do you have a report or something which summarizes all of this somewhere?

MR. CROUCH: We have a task report that's prepared to support this more.

DR. BANERJEE: And it contains all this detail?

MR. CROUCH: Yes.

DR. BANERJEE: And that's available -- has it been submitted to the staff?

MR. CROUCH: No, it has not been submitted to the staff. It was the backup to the report, the submittal to the staff.

DR. BANERJEE: Would it be possible to get a copy to take a look at?

MR. CROUCH: You can talk to Eva about how to do that.

MS. BROWN: We'll take a look and see whether or not that is within the -- our ability to get the reports. I'm not entirely sure. But we'll check back and coordinate with Ralph on whether or not we can get that report.

DR. BANERJEE: It's just to understand the details of what happened. The changes are 100 degrees. These are huge changes. So it's useful to know what happened.

MR. CROUCH: We'll talk to Eva through the afternoon and see what we can do.

DR. BANERJEE: Okay, thanks a lot.

CHAIR BONACA: So let's move on to the

containment of the pressure presentation.

MR. CROUCH: In order to present the containment overpressure today, we have with us two individuals that will be actually making the presentations. Some other individuals will be providing backup. We've got Jim Wolcott here immediately to my left. He is the Extended Power Uprate Project Manager for Units 1, 2 and 3. And then to his left is Bill Eberley who is the Mechanical Nuclear Engineering Manager in Corporate Engineering. And he was the preparer of many of the calculations that actually dealt with containment overpressure. So we have the people here to make the presentation today.

Jim.

MR. WOLCOTT: We have been utilizing containment overpressure in the NPSH calculation as one of the terms in the calculation on Units 2 and 3 at 105 percent power already. This has been done for a LOCA and it was done in response originally to NRC Bulletin 96-03 which dealt with strainer blockage.

That bulletin dealt with a LOCA only. In that particular original analysis, the RHR pumps for the short-term part of the LOCA which is the first 10 minutes requires some containment overpressure and in the longer term part of the analysis greater than 10 minutes is core spray pumps that require some containment over pressure.

For Unit 1, this will be the first time we'll be using containment overpressure as a term in the NPSH calculation.

CHAIR BONACA: When you say greater than 10 minutes, could you give us a sense of how long?

MR. WOLCOTT: Yes, in the current analysis, the total duration in LOCA, that containment overpressure is needed about eight hours.

CHAIR BONACA: You're referring to that Unit 2 and 3 at 105 percent?

MR. WOLCOTT: That's correct.

CHAIR BONACA: Or 120 percent?

MR. WOLCOTT: At 105 percent. I'm speaking of the original one.

DR. CORRADINI: So can I just repeat what you said so I can get it right?

MR. WOLCOTT: Sure.

DR. CORRADINI: So there already has been credit given for Units 2 and 3 at 105 percent for this?

MR. WOLCOTT: That's correct. The dates, I was going to say 1999 was when that was first established as a licensing requirement.

DR. CORRADINI: Just one other -- it's not really fair directly to ask you this, but just give me some feeling, so I am familiar with changes in PWRs relative to things related to power uprates for containment overpressure for different applications and usually there's a band of potential containment pressures that one looks at. So I'm not exactly sure. Is this a mean value, an upper bound value, a lower bound value? Do you see what I'm getting at in terms of uncertainty in the value?

Can you get into that?

MR. WOLCOTT: Yes, we'll get into that.

Slide three.

We have a simplified diagram of the Browns Ferry ECCS system as it relates to determining containment overpressure and positive suction head. We have four total RHR pumps which are down in blue there and each one of those is aligned to its own RHR heat exchanger so there are four total RHR heat exchangers.

CHAIR BONACA: But you're assuming you're losing two, right?

MR. WOLCOTT: That's correct. Some of the analyses lose three and some of them lose two.

CHAIR BONACA: That's a limiting single failure?

MR. WOLCOTT: Using design basis LOCA rules, a limiting single failure leaves us with two RHR pumps and heat exchangers. We'll cover that a little bit more.

The RHR system is capable of several modes that are drawn on here. They can inject to the reactor vessel in the LPSI mode. They can return the water to the suppression pool cooling mode and they can cool the containment through containment spray, either in the dry well part of the containment or the wet well air space part of the containment.

We also have four core spray pumps which are shown in yellow there and they are only capable of core cooling. They spray water inside the core on the core shroud.

DR. BANERJEE: Are your suction strainers, not sump screens, are these like in Vermont Yankee?

MR. WOLCOTT: They are stacked, GE stacked disked suction strainers.

DR. BANERJEE: They're laid horizontally, right?

MR. WOLCOTT: No.

DR. BANERJEE: How are they done?

MR. WOLCOTT: Ours are on the wall of the torus.

DR. BANERJEE: Right. How far from the liquid surface are they?

MR. WOLCOTT: I don't know.

MR. EBERLEY: The plans where the strainer assembly attaches is at elevation 5.7 feet and the water surface, minimum water level is at 5.36 feet, so it's -- the base of the strainer is submerged at that difference.

DR. BANERJEE: And the top?

MR. CROUCH: About four feet. They angle into the water volume on an angle, on a 45 degree angle thereabouts.

DR. BANERJEE: How far from the water surface is the top of the strainers?

MR. CROUCH: I can get back to you and get a detailed figure for you.

DR. BANERJEE: Just roughly, four or five feet.

MR. CROUCH: It's five, six feet, something like that.

MR. EBERLEY: It's on the order of five feet.

MR. WOLCOTT: The suction side of our

system is a little bit unique. We have four suction strainers that are stacked disk suction strainers and they supply a common ring header which all of these ECCS pumps share. In many plants, the different divisions of pumps have their own strainer.

Our pumps share the strainers and that makes for a little bit of suction side interaction when we're running more than one pump or groups of pumps.

Slide four.

The NPSH analysis that we have submitted is done at 120 percent of original license thermal power and that bounds any result that we would get at 105 percent power.

We have four events that we're required to analyzed as part of the licensing basis which would require containment overpressure as part of the NPSH equation in order to meet the manufacturer's required NPSH.

DR. CORRADINI: Can I just interject one question so I understand?

So you did this analysis at 120. In the previous presentation we were given there was essentially a set of data on operating data for the machine where it shows the thermal power, feedwater, etcetera and I assume all the temperatures are associated with 105. So what is the changes in what we might see here relative to these accidents at 120? Is that easily estimated?

MR. WOLCOTT: The major contributor and possibly the only contributor from increased license thermal power is the decay heat curve that would result from operating at a higher power.

DR. CORRADINI: All other parameters are essentially identical at 105 and 120?

MR. WOLCOTT: I believe it would be true to say that they're all identical. I can't think of one that's not.

MR. CROUCH: Core and sump cooling is just slightly different, but the reactor pressure is the same, so that overall the average temperature of the water should be about the same.

DR. CORRADINI: Thank you.

DR. BANERJEE: The energy release during LOCA, would that be more or less the same, 120 to 105?

MR. WOLCOTT: Yes. It's very close to the same -- you have, part of the difference though. There's a little bit more stored energy. If you're comparing Unit 1 before having increased power level -- I'm sorry, increased pressure to here.

DR. BANERJEE: Is that 20 percent more stored energy or 15 percent?

MR. WOLCOTT: It's a very small difference, but it probably is a difference that would only manifest itself in the real short period of time and then soon be overwhelmed by the difference in decay heat which is the major difference by leaps and bounds.

DR. BANERJEE: Well, the fuel is 105 and 120 is the same.

MR. WOLCOTT: Operating at the same temperature.

DR. BANERJEE: But operating at a higher power?

MR. WOLCOTT: That's correct.

DR. BANERJEE: Wouldn't you expect the stored energy in the fuel to be a bit higher?

MR. WOLCOTT: Yes. That's all accounted for in the difference in licensed thermal power.

DR. BANERJEE: Right, so if there is an increase in the stored energy in the fuel, that has to come out, right?

MR. WOLCOTT: Yes, it does.

DR. BANERJEE: During LOCA.

MR. WOLCOTT: Yes. What I was responding

to is I probably had overlooked the fact that there's a little bit more stored energy in the vessel because Unit 1 from where it's currently licensed to now is operating at a little bit higher pressure. So there's a little bit more stored energy there.

DR. CORRADINI: Pardon us for being so picky, I want to make sure. So I was just guestimating that in your data here for 105, you went up 5 percent in flow, so you went up a smidge in inlet subcooling and a little bit in operating pressure to make up for frictional pressure loss, but essentially everything was taken up by an increase in flow rate, if I understood the data for 105 that you gave us.

So at 120, I assume you just bump it 15 more percent in flow rate?

MR. WOLCOTT: Which thing?

DR. CORRADINI: Going from 105 to 120, I don't have the 120 right in front of me. I assume you increased the flow additionally another 15 percent?

MR. WOLCOTT: Things like feedwater flow, steam flow, that's correct.

DR. CORRADINI: Okay. And then just to follow through on Sanjoy's point, so if I increase that, my heat transfer coefficient goes up which means slightly --

DR. BANERJEE: It doesn't go up much.

DR. CORRADINI: But the boiling heat transfer may go up a little bit, so that cools down the stored heat, but it's overwhelmed or taken over by the 15 percent increase in thermal power?

DR. BANERJEE: But how many full powered sections are stored normally at 105 in the fuel?

MR. RAO: This is Dilip Rao from GE. The way we model the total shutdown power in the LOCA is the shutdown power consists of a -- the decay heat, the stored energy in the fuel and the reaction from the metal water reaction and the last two terms are selected generically and they're rationalized so that at the higher power you would essentially be multiplying by a larger number, so you proportionately have a higher value for both the stored energy and the metal water reaction term in the shutdown power table.

DR. BANERJEE: What I'm trying to understand is how much energy is released during LOCA. Let's say large break LOCA, keep it simple. In 105 percent versus 120 percent, let's say during the blowdown phase, forget the -- how much more energy is released?

MR. RAO: For the constant pressure, the conditions in the reactor would be the same, the fluid conditions and the temperature would be the same for both 105 and 120.

DR. BANERJEE: But the heat in the fuel has to come out somewhere, right?

MR. RAO: This would be carried through the fuel and the way it's from fuel to the coolant, the way it's modeled is that we actually attach that to the decay heat term as a total shutdown power table from time zero for the entire event.

DR. BANERJEE: Whichever way you cut it, I'm just trying to get a feel for are you going to have 15 percent more energy deposited in the containment or not during blowdown?

MR. WOLCOTT: The total energy released is going to be the area under the time decay heat curve over the course of the event.

DR. BANERJEE: Plus the stored energy in the fuel.

MR. WOLCOTT: Plus the stored energy that's dumped to start with. Now I couldn't put that in watt-seconds.

DR. BANERJEE: That's the question we're asking. Simply to understand how much energy is being deposited in the containment.

MR. CROUCH: Why don't we take that

question and get back to you later on. We'll have GE guys look into that.

DR. ABDEL-KHALIK: Let me ask a question that's more directed towards the first statement. You say that the analysis of 120 percent power in terms of the -- I suppose of the net positive suction head bounds the 105 percent power?

MR. WOLCOTT: Correct.

DR. ABDEL-KHALIK: Now does that mean that the required net positive suction head at 120 percent power is greater than the required net positive suction head at 105 percent or that the available net positive suction head at 120 percent power is less than the available net positive suction head at 105 percent? Which one of these? Or both?

MR. WOLCOTT: The required net positive suction head does not change with the change in power level.

DR. ABDEL-KHALIK: Even though the temperature might change?

MR. WOLCOTT: That's correct. The required net positive suction head is independent of temperature. The available, of course, is not. The available net positive suction head goes down as temperature goes up. So that's what is changing here.

DR. ABDEL-KHALIK: Okay.

MR. WOLCOTT: So to --

MR. CROUCH: And you'll see that in his slides as he goes on.

DR. ABDEL-KHALIK: Okay.

MR. WOLCOTT: Did that answer your question?

DR. ABDEL-KHALIK: Yes.

MR. WOLCOTT: So we have -- continuing on with this slide, there are four events that require containment overpressure. These are four events that we are required to analyze as part of the licensing basis that we have to include an overpressure in order to meet the vendor's required NPSH and they are the loss of coolant accident, anticipated transient without scram, station blackout and Appendix R fire.

CHAIR BONACA: Now the existing credit for Unit 2 and 3 is only for LOCA?

MR. WOLCOTT: That's correct. Up to this point, we've only analyzed LOCA at this level of detail.

DR. BANERJEE: And that's with SAFER/GESTR or something else?

MR. WOLCOTT: Is this primarily Super Hex. The code that's used to generate the containment responses is Super Hex.

DR. BANERJEE: I'm saying the LOCA itself. It is -- how do you analyze the LOCA?

MR. WOLCOTT: For core or impact on --

DR. BANERJEE: Yes.

MR. WOLCOTT: That would be SAFER/GSTR.

DR. BANERJEE: Not -- you didn't use TRAKG for any piece of it. And for the large break?

MR. LOBEL: This is Richard Lobel with the staff. Let me just clarify something. We're talking about containment analyses now, not LOCA analysis. So the code that's used for modeling the mass and energy release into the containment is the GE LAM code. It's not SAFER/GESTR. SAFER/GESTR is for the peak cladding temperature analyses that they do.

DR. BANERJEE: For the energy release, you use a different code?

MR. LOBEL: For the mass and energy release, yes.

It's an approved code, approved GE code that is listed in the licensing topical reports that go back to the early days of GE power uprate analysis.

DR. CORRADINI: So -- if this is an appropriate time, unless you want to defer it, I'm curious about the condensation heat transfer coefficient you used in this approved code. Do you use Uchita Tagami per license evaluation or do you use something different?

MR. RAO: We do have the Uchita condensation model.

DR. CORRADINI: And that's what you're using?

MR. RAO: That's correct. By way of clarification and for the purpose of the long-term containment analysis, we used the SUPER X code. The LAM code is used as a blowdown for the short term response.

DR. CORRADINI: Right, but where I'm going with this is Tagami Uchita at least as is specified for PWRs is known to be conservative from the standpoint it under estimates the heat transfer coefficient.

So I'm trying to get a feeling for how the response you're predicting is affected by the uncertainty in the lost term to the containment cold wall.

So that's where I'm going with all these questions. So you can do it now or you can do it later, but that's where I'm curious.

MR. RAO: We'd have to get back to you

with a detailed response.

MR. CROUCH: Let us talk about that later.

DR. BANERJEE: I will still -- I'm going back. LAM is only a -- the way you are describing it, has its input then coming in from the LOCA, right? Oh no. Or does it try to calculate also the energy and mass?

MR. RAO: LAM is actually a code that calculates the mass and energy release to the containment and it is used for the purpose of determining the peak containment pressure in the short term on the order of several seconds for the purpose of the NPSH calculation. We use a code Super Hex which has an integrated vessel, dry well and wet well representation and blowdown is calculated with this integrated model of a vessel blowing down into a dry well.

DR. BANERJEE: So now would it get a different mass and energy release during blowdown from say what you would get from your SAFER/GESTR calculations? Or is it the same?

MR. PAPPONE: This is Dan Pappone from GE. The basic blowdown when we're looking at the mass and inventory and the energy, all three codes are set up to model the same reactor, the same inventory, the same core power. And it's really when we get to the different applications that we'll see some of the differences.

The LAM code we're looking at, just the initial reactor blowdown pressurization of the dry well that feeding into pressurization of the wet well, the back pressure and peak containment pressure is for the load is in the very short term. So in that sense we're not interested in the stored energy coming out of the fuel because the time period that we're looking at is very short.

DR. BANERJEE: How long is that?

MR. PAPPONE: Within the first 10 seconds or so.

DR. BANERJEE: Okay.

MR. PAPPONE: For SAFER/GESTR, we're looking at the blowdown inventory, core uncovery and heat up for the purposes of calculating the peak clad temperatures during the LOCA on the fuel. When we get to Super Hex for the long-term containment analyses, again, we're starting with the same inventory volume, the same initial energy, but we're looking at the heat dumped into the containment into the pool, starting -- well, we've got the right values, but we're not concerned with that very early blowdown part. We do calculate and do track the energy moving from the vessel into the dry well and into the wet well.

DR. BANERJEE: It starts from 10 seconds?

MR. PAPPONE: No, no. It's starting from time zero again, but we don't have the details in the model to accurately track what's going on during those first few 10 seconds. But again, for the problem, we're looking at what's happening several hours out in the event, so we're not concerned with the details right at the beginning. We're interested in the peak clad temperatures long term for the Super Hex containment calculations that --

DR. BANERJEE: Do your -- let's say a Super Hex or your LAM, whatever it is, the energy going into the containment and the mass going into the containment and the mass going into the containment, are they consistent with your SAFER/GESTR calculations or not?

MR. PAPPONE: On the first order, yes, but that's also when you get into the -- if you go to the next order, that's where you start seeing the differences in the details of the vessel modeling coming in. So on LAM, we explicitly model the recirculation loop because that code was designed for the initial blowdown, the initial recirc, recirculation coastdown, flow through the core and it's also one of the reasons we're using it for the short term containment analysis because it does a better job of modeling the inventory coming out of the various regions of the reactor during that very short term blowdown.

When we get to SAFER, SAFER includes the volume of the recirculation loops in the vessel volume. But it doesn't have the detail of an external recirculation loop. For the purposes of the SAFER analysis, that's effectively being taken care of by the LAM code in a separate analysis. We're bringing in -- we're using LAM and TASK to calculate the fuel dryout time for that initial blowdown to go into the core heatup calculation.

So we're not interested in that one. We get over to a containment analysis, but we do have -- so on SAFER, we are tracking the inventory and then Super Hex again, we're starting with the same vessel inventory. That vessel inventory is effectively emptying out during the first few seconds into the dry well and then tracking and flowing into the wet well.

So it's a matter of what part of the problem we're looking at and where are we interested in those details and whether or not we need to detail

-- have that detailed modeling in the reactor vessel.

DR. BANERJEE: When does the peak pressure in the containment occur?

MR. PAPPONE: For the initial blowdown, we've got that.

MR. RAO: For a combined LAM model with the short-term containment response occurs in the order of 10 to 12 seconds into the event.

DR. BANERJEE: And when do you actually require credit for containment pressure, how far down?

MR. CROUCH: I think you'll see that's covered in our presentation.

DR. BANERJEE: I'm just trying to understand the time scales for when you have to get good modeling of the energy and mass release into the system?

MR. RAO: For the purpose of NPSH, it is my understanding that it is at least on the order of a few minutes into the event, not on the order of 10 or 12 seconds.

DR. BANERJEE: Okay. So currently, if I understand your methodology, you're using LAM to get the first peak in your containment pressure and you're using Super Hex to get your long-term pressure behavior and containment, right?

MR. RAO: That is correct.

DR. BANERJEE: Now the energy release though is not being calculated by a LOCA code. It's somehow a piece of this code, but how can you do that energy and mass release without knowing what's happening in the reactor because the release depends on the conditions upstream of the break, right?

MR. RAO: We have a reactor vessel model. It is a simple model. It does take into account the mass of the reactor metal and the internals. It does account for the fluid and steam inventory at time zero prior to the break occurring in this integrated model that's in Super Hex.

DR. BANERJEE: Was just a lumped parameter?

MR. RAO: That's correct. It is a single volume which has liquid and it has steam.

DR. BANERJEE: Is it conservative or is it nonconservative?

MR. RAO: There is one conservative presently and we assume that all of the liquid is saturated, but in reality there would be a subcooled fraction in the vessel. But as far as conservatism to the total energy, we assume it is entirely saturated.

DR. BANERJEE: But wouldn't you get a

higher steam fraction near the break than a well mixed model which would give you a higher energy release? Just if you look at straight forward thermal hydraulics than a lumped parameter model.

MR. PAPPONE: This is Dan Pappone. That's true, but again when we look at the time scale, that would be important for the initial reactor blowdown in emptying the inventory, emptying essentially flushing out the --

DR. BANERJEE: The first 10 seconds, certainly that's true.

MR. PAPPONE: But when we get over to the -- when we look at the NPSH calculation, we're not concerned about NPSH until several minutes to hours. So by that time, the simplification in the reactor modeling really won't pay a part any more because we'll already have assumed that that energy has been dumped into the containment.

DR. BANERJEE: For NPSH it should be okay, but not for the peak pressure?

MR. PAPPONE: Right, for the peak pressure, where we're looking at the structural loads on the containment, that's where we'll need the more accurate modeling and that's where we're using more accurate modeling from the LAM code to give us that detailed blowdown.

DR. BANERJEE: So does LAM use a lumped parameter for the reactor or does it have a distributed system?

MR. PAPPONE: LAM has got a distributed system. Its modeling pressure drops between major regions inside of the vessel. It does account for the subcooling and the lower plenum below the feedwater inlet and in the lower plenum does account for that subcooling. It models the break flow path through the jet pump nozzles and also through the recirculation loop.

DR. ABDEL-KHALIK: I guess just to follow up on this, what concerns me here in this discussion is that what is considered conservative from the standpoint of calculating peak containment pressure is nonconservative from the standpoint of calculating NPSH.

MR. CROUCH: Absolutely.

DR. ABDEL-KHALIK: And the question is how do you handle that sort of on one side it's conservative and on the other side it's not conservative? Are you doing two different calculations?

MR. CROUCH: Absolutely.

DR. ABDEL-KHALIK: Or are you doing the same calculation?

MR. WOLCOTT: We turn everything in reverse as far as -- in the way of conservatism, we turn everything in reverse when we are computing the containment pressure that we're going to take credit for in net positive suction head. It's reversed from where we are trying to compute containment pressure for the purposes of peak pressure on containment, so we take both of each of the conservatisms and basically reverse them where they drive the pressure lower rather than higher.

So we do that. That's something that's part of Reg. Guide 1.82, rev. 3.

DR. ABDEL-KHALIK: Okay.

MR. WOLCOTT: Does that answer your question?

DR. ABDEL-KHALIK: Yes.

DR. BANERJEE: What about ATWS? You said you didn't analyze ATWS?

Are you going to tell us --

MR. WOLCOTT: Core events, LOCA, ATWS, station blackout and Appendix R are all analyzed for net positive suction head with some credit for containment of pressure.

DR. BANERJEE: How did you analyze ATWS? What tools did you use?

We understood what you used for LOCA.

MR. WOLCOTT: ATWS, the tools that were used for ATWS would be the ODIN code to compute the power generated phase of the ATWS and Super Hex to handle the containment phase.

Slide five.

The effect of power uprates on net positive suction head are driven by an increase in suppression pool temperature. To give you an example for a LOCA, the peak suppression pool temperature at original license thermal power would have been 177 degrees; for 105 percent or original power, all of the things held equal, it would be 180 degrees; and for 120 percent analysis, it's 187 degrees.

DR. BANERJEE: Is this for Unit 1?

MR. WOLCOTT: Yes.

DR. BANERJEE: Unit 2 and 3 have different fuel, right?

MR. WOLCOTT: They have different fuel, but because this is driven by the thermal power level in decay heat which is essentially the same, the units are physically the same in this regard and the results of their 120 percent calculations are the same. So there are three identical calculations.

DR. BANERJEE: But most of this effect is coming from the decay heat and not from the stored energy.

MR. WOLCOTT: That's correct. The decay heat, particularly, the longer out you get in time, the decay heat dominates this.

Slide six.

I'll go over the basic elements of our net positive suction head analysis. The first thing we do is -- what we've been talking about here is we calculate a suppression pool temperature profile. This would be a time-temperature profile. We take our conservative assumptions in the direction that would maximize the temperature. The next element we would look at is elevation head. That's pretty much fixed by the geometry of the plant doesn't vary from event to event. It has to do with the difference in elevation between pool and the pumps largely.

We have to chooses the ECCS pump flows that we're going to use in the analysis because required NPSH is flow dependent and so are suction losses. So for analyzing each event, we have to choose the appropriate bounding flow to use.

Once we know the flow, we have to compute suction pressure drops and that consists of the piping pressure drops which we use standard industry methods to do that. And suction strainer blockage and pressure losses which are done in accordance with the BWR owners' group, URG methodology which is NRC-approved.

In our particular plan, we are designed with reflective metal insulation on the primary system rather than fibrous insulation and that gives us quite a bit of advantage as far as strainer debris blockage.

DR. BANERJEE: You have no particles or fibers?

MR. WOLCOTT: We don't -- we have a very small amount of fibers that are back inside of pipe penetrations which are accessible as blown out debris only in the case of paint work inside of the penetration, so once you take that small amount of fiber and spread it out, over the strainers, it's not significant compared to the reflective metal.

We do include other types of debris that are standard from that URG, paint chips, sand, sludge.

DR. BANERJEE: You have no particulate material in your insulation?

MR. WOLCOTT: No, the reflective mirror insulation wouldn't -- metal foil and stainless steel sheathing.

DR. CORRADINI: So if I may just -- I'm looking at it and trying to get a simple equation in my head. So what you're basically telling me is the pressure on the wet wall plus the hydrostatic head minus the wet well minus the -- excuse me, the temperature of the water, minus the delta Ps must be greater than your NPSH?

MR. WOLCOTT: Greater than the required.

DR. CORRADINI: Excuse me, I'm sorry. And then your point is by changing the temperature 10 degrees, that's the margin you need, 10 degrees out?

MR. WOLCOTT: If you change the temperature 10 degrees, then that would increase the vapor pressure by a certain amount and would take away that particular amount of margin from the PSH equation.

DR. BANERJEE: Did you do any strainer tests or are you just using data?

MR. WOLCOTT: URG methodology on strainer tests, I'll let Bill talk about that.

MR. EBERLEY: GE did prototype tests and strainer testing on this GE design, stacked disk strainer.

DR. BANERJEE: Did they do it with single strainers or did they actually stack them and do them?

MR. EBERLEY: I can't speak to that.

MR. CROUCH: They had actual stack strainers. They went out and took various kinds of reflective metal insulation, both mirror insulation and transco, subjected it to steam jets so that it would form the foils that came out, took the foils and dumped them into a test tank. They would have a strainer down there, then they would dump in various amounts of sludge and other things that were part of the possible things that would be inside people's containments. Then they ran the pumps and measured the delta-P across the stacked disk strainers.

DR. BANERJEE: They were like prototypical, full-size --

MR. CROUCH: Yes.

DR. BANERJEE: -- strainers? Is that documented somewhere, these stats?

MR. CROUCH: Oh yes. There's about a 5- or 6-volume report on the URG methodology.

DR. BANERJEE: With these specific materials you're using?

MR. CROUCH: Yes. It was all NRC-approved back in the 1997 to 1998 time frame.

DR. BANERJEE: And you're using the same type of insulation?

MR. CROUCH: Yes.

MR. WOLCOTT: I was going down the list of elements. The next one is determining a required NPSH. That's supplied by the pump vendor. In our particular case, the required NPSH has been given to us in, as a function of time duration. We can withstand less NPSH and more cavitation if we do it for a shorter period of time. So, we, our NPSH requirement changes and becomes more restrictive the longer time duration we want to bear the reduced NPSH condition.

DR. KRESS: And that time curve is supplied by the pump vendor?

MR. WOLCOTT: That's correct.

DR. KRESS: And he knows very little about temperatures at the core and stuff, so it must be on the basis of when the pump would fail, or?

MR. WOLCOTT: No. It's based on, it's based on testing that was originally done on our pumps and how far they were, they have data on the pump as far as, how far they've, how far they've tested it that way and what kind of results they got from it. And they conservatively constructed for us a time-duration versus reduced NPSH curve that they felt comfortable with would result in being continued to operate the pump.

The pumps are normally designed for 8,000 hours of operation, so the standard single number that you're given would be a number that you could operate at for 8,000 hours. We don't do that with these pumps.

DR. BANERJEE: This is the Salzer report that we have?

MR. WOLCOTT: That's correct. That's the Salzer report that you have.

DR. BANERJEE: But my impression was they don't have any data at higher temperatures, right? I mean they, I --

MR. WOLCOTT: The tests were done at, you know, ambient temperatures --

DR. BANERJEE: Right.

MR. WOLCOTT: -- ninety degrees. We've discussed that with them several times and they are, they feel like doing it a lower temperatures is conservative relative to doing it at higher temperatures. The temperature, the main, the main effect of the temperature of the water is built into the NTSH equation via vapor pressure. And so, largely

NPSH test results can be translated from one temperature to another by vapor pressure.

DR. KRESS: Well, what happens to the pumps in time? Do they slowly lose flow or do they go along and quit?

MR. WOLCOTT: It's a function of time.

DR. KRESS: I know, but do they slowly lose flow or what --

MR. WOLCOTT: No. What would happen is a function of time. If you believed that you had cavitation, cavitation causes impeller erosion.

DR. KRESS: Right.

MR. WOLCOTT: And it causes vibration which, which eventually would, you know, would wear out the machine. So, what they've done is take that out over, take that out over a function of time. Erosion doesn't occur instantaneously, and fatigue and vibration damage doesn't occur instantaneously. So, over time, there would be slow degradation. Over time. I think that was the question I asked.

MR. CROUCH: In other words, it would not be a step function, just instantaneous failure of a pump at any time. It would be a slow degradation.

DR. BANERJEE: Well, it also depends on how much void is generated.

MR. SIEBER: On the other hand, does, as you reduce NPSH below the pump operating point, there is a decrease in flow which generally falls off parabolically. My experience is that a lot of pumps are running in a slightly-cavitated mode all the time, not severe enough to cause pitting. It's not severe enough to have vibrations that are damaging bearings. And, from a cost versus flow and pressure standpoint it's an efficient way to do it.

DR. CORRADINI: You mean at the very high end of the pump curve?

MR. SIEBER: That's right. But as you continue to reduce NPSH, the flow falls off until it starts to chug and then you can lose flow all together.

DR. KRESS: Well, what I was asking, somewhere on this curve you described, it's cavitating, but the pumps are still running.

MR. SIEBER: Yes.

DR. KRESS: And the question is how long is it going to last until something happens and my question was does that something happen all at once by an impeller breaking or a bearing seizing or does the flow continue to decrease slowly because the impellers are losing effectiveness some way. I don't know.

MR. SIEBER: I think it depends on where you are on the curve. When you look at a pump that has been cavitating slightly, has run its full, normal period between maintenance, for a maintenance interval, you will see all kinds of pits on the face of the impeller, but the pump will have pumped all that time and otherwise will not be damaged. The seals are still good, the bearings are still good.

On the other hand, if you reduce it to an even lower NPSH, you could induce a failure relatively quickly. Depending on the total head developed across the pump, that's one factor in determining how quickly the pump will fail. For example, a pump that delivers 50 feet of head is going to last longer than one that delivers 250 feet of head.

DR. KRESS: Well, let me ask the question another way. I'm still not getting the answer. The question I have is you have a time to operate versus a net positive suction that was supplied by the vendor. How did he get that time? What happened to say this is the time. You no longer should operate beyond this.

MR. SIEBER: Well, they don't operate the pump to destruction.

DR. KRESS: How do they know when to quit this process?

They just quit at a certain arbitrary time?

DR. BANERJEE: They have taken a baseline as a year in the report.

CHAIR BONACA: Didn't you say the SER, they're talking about a limited time of cavitation? If I remember in the SER it speaks of four minutes.

DR. BANERJEE: I don't know exactly what it means.

CHAIR BONACA: From what I was reading it seems as if there were four minutes of cavitation in the first ten minutes of the transient and for those four minutes, there was specific information provided by the vendor so there was a limited time to be addressed in the evaluation. That's my understanding.

You presented a time of cavitation and the vendor evaluated and said four minutes is not a problem and then you went back and checked because the test you did for the Unit 3 pump was done for those time frames? Could you explain that to me? Because I mean that's what is being referenced in the SER.

MR. EBERLEY: We can do that. We might be covering that a little bit.

CHAIR BONACA: There was a test done for

one of the RHR pumps at Unit 3 that produced these characteristics. I mean they --

MR. LOBEL: This is Richard Lobel from the staff. I think we're mixing two things together here. What TVA is talking about is a curve with recommendations from the pump vendor on required NPSH and we talked about the same type of curve when we were talking about Vermont Yankee. Vermont Yankee used the same -- has the same pump vendor and they supplied the same kind of curves.

And what the pump vendor does essentially is the pump vendor has, I don't know, Salzer Bingham probably has a hundred years of experience in designing pumps and testing pumps. And I can't explain all the details of what they did and it's probably proprietary to the pump vendor, but usually, their knowledge base and they're testing pumps, they made recommendations of how long a pump could operate at a certain level of required NPSH before that level had to increase.

I had, in my presentation, I have the curve. I can show you the curve. The four minutes refers to a Browns Ferry specific time that comes from their LOCA analysis and that includes credit for this pump vendor curve. But those are two separate things.

The four minutes and the pump vendor curve are two separate items.

CHAIR BONACA: I understand that. I said we're only looking for how long credit is being requested for.

MR. LOBEL: Four minutes.

CHAIR BONACA: That's right.

MR. LOBEL: Yes.

CHAIR BONACA: So that sets some kind of limit to -- I mean, sets this up in the horizon for how far we're going to do that. Now the pump vendor may not address that specifically when he tells me it's not 20 hours.

MR. LOBEL: Well, the pump vendor did address it and I'm going to get into that in my presentation. Maybe the thing to do is to go on for now and when I get to that point in my presentation, we can discuss it again with the licensee.

I don't want to answer all the questions for the licensee, but --

CHAIR BONACA: I'm trying to understand the reason being provided that tells us that and -- okay, so we'll talk about that later.

MR. EBERLEY: Can I say one short thing about this? For example, for the core spray pump in one of our long term LOCA analysis, we applied an NPSH requirement of 29 feet from this curb which Rich mentioned -- 29 feet, we applied that value. That value, if you provide 29 feet of net positive suction head to that pump, you can run it from 24 hours to 8,000 hours for, you know, its life. So that's the requirement to run the pump indefinitely, at 29 feet.

For that event, we only analyze it for 24 hours. That's the limit of the period of the time for the long-term LOCA analysis where we are back down to atmospheric pressure and didn't require any overpressure whatsoever. So we're talking about applying a requirement that's good for the whole life of the pump for 8,000 hours, applying it to an event where we only needed credit for 24 hours.

DR. CORRADINI: So if I can get back to that, because I'm still of kind of listening to what Sanjoy was asking what Said was asking. I just tried to back calculate it. Perhaps I did it wrong, but my impression is that from 100 percent to 120 percent, we're talking a tenth of a bar. So 1.4 psia. Am I right? So you're looking for credit of 1.4 psia between the 100 and 120 hour and you're looking to add that onto the wet well pressure.

MR. WOLCOTT: That's close. It's a little short.

MR. EBERLEY: Yes, using steam tables, I had 1.7 psi.

DR. CORRADINI: All right. I'm just trying to get a level for this. The only reason I'm asking the magnitude is to go back to Said's question is somewhere in yours or somebody's presentation, the protocol on how you conservatively added or taken away, I guess we want to understand your budgeting?

DR. ABDEL-KHALIK: This difference between the conservative analysis on one side?

MR. WOLCOTT: Let us get deeper into it. I think we'll cover some of that stuff.

DR. BANERJEE: How much of a pressure loss did you have across suction strainer?

MR. WOLCOTT: In the long term analysis at the flow that we have there it is .4 feet. But in short term, where there is a whole lot more flow, it is probably about 5.7 feet.

DR. BANERJEE: So that's about a couple of psi.

MR. WOLCOTT: Okay, continuing to go down this list and the final thing that we have to calculate is if we're going to use containment overpressure, is the wet well pressure term. That is calculated, as we have already said, using Super Hex and taking all of our assumptions and turning them so that they drive the pressure to be the minimum pressure that you would expect to have, rather than the maximum pressure.

So we have two competing and inconsistent sets of assumptions that we make here. In containment analysis, we make one set of assumptions to drive the suppression pool temperature profile high. And then turn those assumptions around in the same analysis to drive the pressure low.

Slide seven.

We are going to go over two of the events in detailed analysis just to get a look at what they look like. The first one will look at is the LOCA, and that analysis is done in two separate phases, the short-term phase that's done in the first ten minutes of the event, and the long-term phase which is done greater than ten minutes.

CHAIR BONACA: That's when you switch to containment spray

MR. WOLCOTT: That's correct. There are manual alignment changes that are assumed to occur at or before ten minutes, and that's what makes that break point. That's why the analysis is different before and after.

CHAIR BONACA: Now for public context, it says NPSH licensing basis analysis.

MR. WOLCOTT: Yes, we're still talking about the licensing basis analysis here.

CHAIR BONACA: Unit 1, 120 percent power.

MR. WOLCOTT: This is at 120 percent, that's correct.

CHAIR BONACA: Go ahead.

MR. WOLCOTT: In the short term analysis, all the pumps that get an automatic start signal are assumed to start, their valves to open, and they are assumed to go to the flaw that they would go to match the system head with the valves widening. So there are four core spray pumps doing that, and two RHR pumps doing that. They're injecting to the vessel.

In addition to that, we take and assume that two of the RHR pumps are connected to the broken loop which was the source of the LOCA to start with. That has much less systems resistance on it because it just has a piece of pipe and so that flow goes quite a bit higher and forms the most bounding requirement for NPSH required because the flow is so high.

There is debris loading on the strainers in accordance with the URG methodology and in the 120 percent analysis, both the RHR and core spray pumps require some containment overpressure in order to meet the NPSH required from the vendor.

CHAIR BONACA: You have a single failure here and that's the other train, no?

MR. WOLCOTT: In the short term assuming, strange as it seems, assuming a single failure would be non-conservative, because in this short-term part of the analysis the NPSH problem is being caused by so many pumps demanding so much flow.

CHAIR BONACA: Okay.

MR. WOLCOTT: So we don't have any single failures in the short term so that all the pumps run at their full flow and put their full demand on the suction side.

MR. CROUCH: It's just like what we were talking about earlier when we maximize assumptions.

CHAIR BONACA: I understand.

MR. CROUCH: In this case, maximize assumptions means to maximize the flow rate.

Jim, one thing you might want to talk about a little bit is the broken loop and why we're concerned about that broken loop in the pumps there.

DR. BANERJEE: Sorry, would there be a single failure that would raise the temperature of the suppression pool?

MR. WOLCOTT: Not in the short term.

DR. BANERJEE: Not in the short term.

MR. WOLCOTT: In the long term, however, any single failure affecting heat removal capability would result in the pool temperature being higher.

MR. CROUCH: These are not the assumptions for the calculations of the pool temperature. Pool temperature assumptions do assume a single failure, but these are the assumptions for figuring out what the flow is through the various pumps.

DR. BANERJEE: Pool temperature already assumes this failure?

MR. WOLCOTT: Correct, yes it does. In the long term

DR. ABDEL-KHALIK: What you're trying to do is essentially underestimate the containment pressure and overestimate the temperature. I can understand how these would because of the higher flow rate that you get in the pumps connected to the broken loop, you have higher pressure drop in the line. But which of these assumptions actually increase or result in a higher than expected water temperature?

MR. WOLCOTT: None of them. In the first ten minutes, we are not assuming any heat removal, because that alignment hasn't occurred yet. So there is no heat being removed. So single failure assumptions of pumps and what have you wouldn't have any influence over what we are analyzing to be the pool temperature, because we're not even crediting any heat removal until ten minutes when the operator has time to line that up.

So having single failures one way or another would not influence the pool temperature. Pool temperature is strictly a function of how much energy is released from the reactor and the physical size of the water body in the suppression pool during that phase.

MR. CROUCH: These assumptions here are the assumptions that are used for calculating the pump flows, not for calculating temperatures. Calculating temperatures, we assume a simple failure would wipe out an entire loop. It maximizes temperature. Just like this slide here, this is one of the bullets on the previous slide, how you maximize the pump flows.

DR. CORRADINI: So somewhere, I have been looking ahead. Somewhere in here I'm kind of curious about the what you were talking about, Said, about that when you maximize, when you try to maximize temperature, the containment pressure is here. When you try to maximize flows, the containment pressure is here, and what the difference is. You're going to get to that somewhere in here?

MR. WOLCOTT: We can talk through that when we look at one of the event graphs, perhaps, we can talk about where it is on there.

DR. BANERJEE: You have four strainers, so if you blocked off one strainer, wouldn't you get more for pressure loss on the suction side?

MR. EBERLEY: We analyzed that suction piping network with the hydraulic flow balance computer code which determines that percentage that each strainer draws from the suppression pool and the worst strainer draws 26 percent of the flow and that's the one we analyzed in all cases, the 26 percent contribution for that one strainer of total flow.

MR. CROUCH: If you were to somehow get all of the debris to go to one strainer and block it off completely, then the other three strainers would be virtually clear, so you'd have very low pressure drop.

DR. BANERJEE: That's not so clear because this is not a linear thing, the pressure losses, especially with fibers. So if you assume one strainer blocked and the other operating with the same sort of pressure drop wouldn't be so far afield, but if that happened would it cause you any significant problem, if that was your single failure?

MR. EBERLEY: No, it wouldn't make this analysis any worse than what we've got. We have full reflective metal insulation saturation thickness, dead thickness on these strainers and we're taking the worse hit that we can from reflective metal source term that we had.

DR. BANERJEE: No, I understand that. But suppose you --

MR. EBERLEY: If it was totally blocked.

DR. BANERJEE: Whatever reason. I mean -- it's a single failure, it would be still be okay?

MR. EBERLEY: Yes.

DR. KRESS: Would your results of this analysis be different if you changed the 10 minutes to something else? Like suppose it were 5 minutes or 15 minutes? Does it change your results significantly?

MR. WOLCOTT: There would be an advantage if the operator takes control earlier, there would be an advantage to taking, a thermal advantage to taking control earlier. So --

DR. KRESS: It would be better off earlier. How about later?

MR. WOLCOTT: Later, even if you weren't considering net positive suction head, our licensing basis aligning containment cooling is manual. And so there is a limit of how long you could wait to align that, because if you do that, you're eventually going to get in trouble because you're not removing any heat in a LOCA.

So our --

DR. KRESS: You would get in trouble elsewhere is what you're saying.

MR. WOLCOTT: Well, all the things that go along with running the water in the torus too high. So yes, there would be a problem if you waited and did not align containment cooling. There would be several problems caused by that.

CHAIR BONACA: How successful are your operators when you test them on the simulator?

MR. CROUCH: Tony?

MR. ELMS: Tony Elms, Operations Manager. And we're trying the net positive suction head on the simulator and one of the things that we're talking about is as the temperature in containment goes up, you can reduce the flow on the pumps and bring yourself back down. On your flow curve it requires less net positive suction head.

The simulator does mimic the cavitation of the pumps by the amp swinging on the pumps. That also there are two things, loss of net positive suction head as well as strainer plugging. And as you see that we're trained to lower the flow on the core spray and RHR pumps to bring them back within their net positive suction head curve.

There's also curves in the emergency operating instructions that we check in our emergency operating flow charts that will tell us what the maximum flow is for the pressure in the suppression chamber as well as the temperature of the water in the pool. So we have guidance in what flow we can run those pumps at with given pressures and temperatures of water in containment.

MR. WOLCOTT: I think what he was asking, what's involved in aligning containment cooling and all that?

MR. ELMS: Aligned containment cooling, you've got an injection valve that you have to close. It's the LPSI injection valve and you have one injection valve that you will open to allow the suppression pool cooling and you've got a service water heat exchanger that you'll have to open the outlet valve to align the RHR service water to cool the water.

CHAIR BONACA: And the question I had was in simulator exercises are the operators successful in identifying and performing the switch over in 10 minutes?

MR. ELMS: Yes, sir. That would be a critical step in the simulator exercise that would test this part of the emergency operating procedures and if the crew did not successfully complete that in a given time frame, they would go through a remediation process.

CHAIR BONACA: Okay, all right. Thank you.

MR. WOLCOTT: After ten minutes in the analysis which we call the long-term analysis, we cut back to two core spray pumps at design flow rate where the operator can throttle the system, rather than letting it run wide open and two RHR pumps in containment cooling mode. There is debris loading on the strainer during this period of time also. The pressure drop isn't as much because the flow isn't as much because we're stopping the pumps that we don't need.

And in this particular part of the event, it's only the core spray pumps that require containment overpressure. The RHR pumps do not.

So with that --

DR. BANERJEE: Is there any vortexing in the vicinity of the strainers?

MR. WOLCOTT: We analyzed for that because that's one of the things you have to look for.

DR. BANERJEE: How do you analyze that?

MR. WOLCOTT: I'm not sure I can answer that question.

DR. BANERJEE: Does GE analyze it? Who analyzes it?

MR. EBERLEY: We did.

MR. CROUCH: Let us take that as a question and get back to you.

MR. WOLCOTT: We will turn to slide eight then. This is the event graph that represents the LOCA analysis I just talked about. This graph is for the long-term part phase of that analysis.

The top most red line there is the containment pressure, computed using assumptions that minimize the containment pressure.

The second line down or the blue line is the suppression pool temperature.

DR. CORRADINI: So can you give me an idea of the -- I'm trying to get the right words here, the uncertainty on the red line versus your ability to move it based on assumptions? In other words, you're predicting a peak pressure of 21 psia, plus or minus something based on how you model it, compared to you noodling with the model to make it as low as possible and what's that plus or minus? That's kind of where Said was asking that a while back. Do you see where I'm getting?

MR. WOLCOTT: Let me answer that first and then I'll let GE take a second crack at it. There is a great deal of conservatism buried in all of the aspects in the way we do this thing. When we're in doubt, we take a conservatism, that's just the nature of how we do things.

MR. CROUCH: We take a conservatism to drive the pressure down.

MR. WOLCOTT: Well, to take whatever the conservative direction is. That's how we make up for uncertainties, so my answer to that would be that this curve is still unrealistically conservative, if you went and picked apart all the conservatives that are buried in it.

MR. CROUCH: So the pressure would be the lower limit and then the temperature would be the upper limit, based on those uncertainties.

DR. BANERJEE: It would be nice if you could show the uncertainty band. This was the lower limit and that was the upper limit.

DR. CORRADINI: Then we'd just get mad at you about that. I just want to know in numbers so I get a feeling for what it is.

DR. BANERJEE: But do you know what it is, the uncertainty?

I mean is it 20 degrees or 5 degrees or what is it? Ten psi, 20 psi, 30 psi? What is the number?

DR. CORRADINI: Let me just make sure you're clear on our logic because probably you're right. You've done all the analysis. We're just here shooting at you. But if it's 21, as your lowest containment pressure and 186 as your highest suppression pool temperature and you're claiming that that's the highest blue and that's the lowest red, I want to know when you try to make it realistic is it 25 and 170 or is it 22 and 285? It's the magnitude, it's the quantitative magnitude of what you know and don't know that is getting us a bit --

DR. KRESS: How much margin --

DR. CORRADINI: Yes, I want to know the margin.

MR. WOLCOTT: We're going to talk later about what these look like when we do it realistically.

Do you want to wait for that and see if that answers your question?

DR. CORRADINI: Sure.

DR. ABDEL-KHALIK: What is the peak containment pressure the way you calculate for a LOCA?

DR. CORRADINI: During this time scale, not the red that's going off scale, but during this time scale?

MR. WOLCOTT: We'd have to pull the curve out and look at it. At this point in time we just usually look at the very peak peak which would be the little spike off the -- to look at the entire duration and how that compares, we'd have to pull the curve out and look at it.

So going on with explaining what these lines are, the reddish line in the middle there is the containment pressure in absolute pounds. The pressure, by the way, is using the righthand axis there and temperatures using the lefthand axis. That is the pressure in the containment absolute that is required to include in the NPSH calculation in order to just match the required NPSH that applies to that time frame.

DR. BANERJEE: This is psia, right?

MR. WOLCOTT: It is absolute pressure in the containment.

DR. BANERJEE: Does that means that -- it's only about four psig?

MR. WOLCOTT: That's correct. Three. The top of it's three.

Now you note the discontinuity right in the middle of that curve there. That is a reflection of the time dependent required NPSH. Because remember, this curve is defined as what it takes to meet the NPSH required that comes from the vendor because the vendor gives us NPSH required in time frames. We have applied that in time steps. This particular step occurs at eight hours and so at eight hours we change the rules and say that it has to have more now.

That step represents no phenomena or anything like that. It's just a change in the rules to make it harder to pass.

DR. ABDEL-KHALIK: So buried in this is the water level in the torus?

MR. WOLCOTT: Yes, it is. The water level in the torus is one of the other terms that is in that line right there.

DR. ABDEL-KHALIK: When you say that the required pressure is 10 psia and you're required the positive suction head is 30 feet, I'm just trying to reconcile these two numbers. It doesn't make sense.

MR. WOLCOTT: There are several more terms in the NPSH equation. One of them is an elevation term.

DR. ABDEL-KHALIK: Right.

MR. WOLCOTT: One of them is in the textbook equation peak peak, PA, P atmosphere. That is the containment overpressure -- the containment pressure term that we're seeing here. What other terms are there? There's the vapor pressure term which is changing with temperature of the water and those all
-- what you're seeing here is the result of those, all added together and just meeting the NPSH required that's given by the vendor. That defines the --

DR. BANERJEE: It would be useful if you might have, you could sketch just the different levels that we have in this system because is there a sketch like that somewhere here?

MR. WOLCOTT: By levels, you mean elevations?

DR. BANERJEE: Yes, right. I mean you have a sketch there, but there are no quantitative numbers, right? So -- just an idea.

MR. WOLCOTT: Yes, to give an idea of magnitude-wise --

DR. BANERJEE: Start with the water level and the torus.

MR. EBERLEY: The suppression pool level would be used in the suppression pool level elevated at 536 feet.

DR. BANERJEE: Right, and the pump.

MR. EBERLEY: The piping system is 527 feet.

The center line of the ring header is 525 feet 4 inches.

The center line of the suction core spray pump is 525 feet 4 inches. The center line of the RHR suction horizontal lines are at 521 feet, 7 inches.

DR. BANERJEE: Okay, thanks.

MR. CROUCH: Okay.

MR. WOLCOTT: Everybody good with that?

DR. BANERJEE: So you are again getting about 15 feet or so just by elevation.

CHAIR BONACA: Yes, so you need apsi for the core spray and you are given no credit for the RHR because it's below atmospheric?

MR. WOLCOTT: Right, just continuing with interpreting this curve, the dashed line that goes across the middle represents atmospheric pressure at Browns Ferry and what we are calling containment overpressure is the difference between the pressure required, the reddish line and atmospheric pressure. So every time that one of these required lines is above the dashed line, that defines the need for containment overpressure.

So as you can see in this one, core spray pump needs, begins to require containment overpressure and then we've shortly, around 24 hours into the event, the temperature has dropped down enough that it ceases to need containment overpressure, that is 14.4 pounds absolute plugged into the NPSH equation will match the vendor's required at that point.

DR. BANERJEE: Is it really hard to get pumps that function with 15 feet instead of 30 feet? Is that the reason why you've sort of gone through all these hoops?

MR. WOLCOTT: Yes.

DR. BANERJEE: Because you can't buy such pumps? Is that the problem?

MR. WOLCOTT: Yes, with a pump with other performance characteristics we'd need, there is no magic pump that would do this. You could certainly do it with different elevations.

DR. BANERJEE: The elevations were pretty fixed.

MR. WOLCOTT: Yes, they are very fixed.

DR. BANERJEE: And you've changed so many things out. I mean why not pick a pump where you didn't have to go through this hassle.

MR. SIEBER: Generally, the way you do that is a lot of these pumps are vertical pumps. You just dig a hole deeper. That's why you had NPSH.

On the other hand, the longer the shaft of the pump, the harder it is to balance and the more likely it is to rip itself apart.

MR. CROUCH: These pumps sit on the base mat of the reactor building, so --

MR. SIEBER: Once you build the plant, putting a new pump in, at a different depth is a mighty expensive deal, meaning you start moving concrete and drilling holes in the ground.

DR. BANERJEE: But it is not easy to get a pump you're saying that has these operating characteristics, 15 feet, rather than 30 feet.

MR. SIEBER: Well, the other thing you

could do is raise containment six or eight feet.

(Laughter.)

That's the other solution. You guys can do it.

DR. BANERJEE: You changed these pumps already or did you keep these for the original pumps?

MR. WOLCOTT: These are the original pumps, they're original design. They have new impellers over the years. These are the originals.

DR. CORRADINI: So I'm looking at this curve. I'm still trying to interpret, so the purple line requires a credit of a little bit less than 2 psia over atmosphere.

MR. WOLCOTT: It's about 3.

DR. CORRADINI: At your discontinuity. Okay, and you're claiming that the lowest containment pressure you can force the calculation to give you with reality is at that same location.

MR. EBERLEY: 3.1 psi higher.

DR. CORRADINI: So that's the margin?

MR. EBERLEY: Correct.

MR. WOLCOTT: We have about twice as much as we need at that closest point there.

MR. EBERLEY: And that point, as I explained earlier, is certainly high because of my choice of the NPSH requirement of 29 feet which is corresponding to that peak. The requirement actually is 24.5 feet at eight hours. It has more to do with margin.

DR. CORRADINI: And nothing you do in the modeling to drive the red line down gets you lower than the line we see?

MR. EBERLEY: That's correct.

MR. WOLCOTT: We have some realistic analyses that can get that line down. They don't follow the licensing basis rules, so staying with the licensing basis rules, we can't get this line down below the dotted line.

DR. CORRADINI: You said something that I'm going to ask you about, unless you rephrase that.

Say that one more time. I thought you told me that the red line is the lowest you can get it within --

MR. EBERLEY: With the available pressure, the standard pressure is the lowest you can get.

DR. BANERJEE: With the licensing basis rules?

MR. WOLCOTT: I'm sorry. I was answering a question about the wrong line. What I said made no sense at all, if you were asking about the top line.

DR. CORRADINI: Yes, I'm asking about the red line.

DR. BANERJEE: That's the lowest realistic line, right, the red line?

MR. EBERLEY: I wouldn't call it realistic because we've gone out of our way to minimize it in a non-mechanistic form.

DR. CORRADINI: What is the thing that most controls -- so that's the next question since we're now talking about the margin. What is the physical parameter that most controls that red line's position quantitatively?

MR. WOLCOTT: The most, I would say it's the -- it's driven the most by the temperature of the water in the torus would be the -- the temperature of the suppression pool water is probably what drives it the most. I mean most determines its value.

DR. CORRADINI: Is that the one you had the highest -- okay.

MR. RAO: Is the question about the containment pressure?

DR. CORRADINI: Yes.

MR. RAO: What we've done to get the most conservative containment pressure is we've minimized the initial pressure in the dry well and wet well. We maximized the relative humidity in the dry well and wet well at times zero. And that helps us to essentially come with the highest critical mass and therefore it gives us the lowest effect, lowest pressure. That, we say is not realistic because I think in reality the humidity is at less than 100 percent, at least in the dry well for sure.

CHAIR BONACA: We are still anxiously waiting for the later part of the representation when you will tell us what it's worth.

At some point I think we'll hear about that.

DR. ABDEL-KHALIK: How about the condensation model that you use in the analysis?

MR. WOLCOTT: Condensation model, are you talking about heat sink?

DR. ABDEL-KHALIK: Condensation model that you use in the containment analysis.

MR. RAO: We do take credit for heat sinks and we do have -- achieved a condensing model, but in the first ten minutes, I believe it's essentially you have about -- it's initially saturated and that is going to heat up because the heat must transfer from the suppression pool as the suppression pool heats up.

DR. ABDEL-KHALIK: But if you have better heat transfer, then whatever you are assuming here, then the red line will go down.

DR. BANERJEE: We are talking about long term here, right?

DR. ABDEL-KHALIK: Correct.

DR. CORRADINI: He answered short term, but we're talking long term.

MR. RAO: After ten minutes, we have assumed that the containment sprays would be on. Essentially, you would be -- have the effects of almost any other phenomenon at that time.

DR. CORRADINI: Okay.

DR. BANERJEE: Would the spray, if you had better condensation or heat transfer to the sprays, would that drag the line down?

MR. RAO: We have assumed 100 percent mixing of the sprays with the atmosphere, both in the dry well and wet well.

DR. BANERJEE: And they're equally -- the slight one equilibrium state?

MR. RAO: That is correct. It assumes an instantaneous equilibrium for the spray with the air.

DR. CORRADINI: Thank you. That answers that. So what about -- so we kind of have red, purple and green margin lines here for the long term. Is that more limiting than the short term ten minutes that you were speaking about?

MR. WOLCOTT: In terms of which of our lines?

DR. CORRADINI: Yes, I'm trying to envisage what this looks like in the first ten minutes now. So we've got this one for LOCA analysis over the long term. Now there's a corresponding set of red, purple and greens -- excuse me. Red and green for the short term which is the RHR is limiting.

MR. WOLCOTT: The staff is going to cover that one in detail, so we were going to not duplicate that.

DR. CORRADINI: Okay.

CHAIR BONACA: That's also in the same mode, about 3 psi?

MR. WOLCOTT: Yes, same order. So the final item I haven't talked about here is the green line which is the RHR pumps. In the long term, they do not require containment overpressure because they don't cross the dotted line.

The other event that we chose to present here is the Appendix R fire event and that particular event, the Appendix R rules as far as how to apply fire damage and loss of off-site power. For one, RHR pump, for the worse case analysis and it is in a mode where it's injecting to the reactor vessel and returning to the suppression pool through the relief valves which we call alternate shutdown cooling mode. There is no strainer debris involved in this event because there's no pipe break inside the dry well that would generate the debris and transport it. And it is the RHR pump that requires containment over pressure in this case.

CHAIR BONACA: Well, you have one RHR pump.

MR. WOLCOTT: That's correct, one and only.

CHAIR BONACA: The single failure is the other pump?

MR. WOLCOTT: Appendix R does not have a single failure in the classic sense. What we do is when we apply the Appendix R rules to the areas of fire damage, we are in some fire areas left with one RHR pump if we applied all the rules. It's not quite a single failure.

Slide 10 is the event very similar to the one we just looked at. The suppression pool temperature is higher in this particular event because we only have one RHR pump operating, rather than two and so we only have half of the heat removal that we would have in the other event approximately.

The containment pressure is the red line there and again it's computed using all of the assumptions that would drive the containment pressure to a minimum value.

DR. CORRADINI: Why is the green line -- maybe I misunderstood. Oh no, this is containment pressure. This is not the actual NPSH. This is the required containment pressure to meet NPSH.

MR. WOLCOTT: That's correct.

DR. CORRADINI: Why is there no bump on this one?

MR. EBERLEY: We refined the analysis on this one in particular because we didn't pass initially when we did the analysis. We were looking at some new ways of doing Appendix R analysis. NPSH hadn't been done before. Taking penalty for dry well coolers being in service and removing heat from the containment. We're in normal containment analysis. We will take credit for, in this case, penalty for the dry well cooler heat removal.

So initial analysis, the lines got close together and we went back and refined the analysis and interpreting the required NPSH curve from the vendor, we interpreted it as a function of lower time, the whole time period. We varied it according to their curve rather than step changes.

DR. CORRADINI: I interpret what you just told me was the green and the red getting damn close.

MR. EBERLEY: They were getting close early on, right there around two hours which is when we now isolate the dry well coolers. And it was a lesson we learned in this analysis that that operation of the dry well coolers can't hurt you, but along the lines of minimizing the overpressure and maximizing the pool temperature.

DR. BANERJEE: The margin here is much less.

MR. WOLCOTT: Much less, very short time frame there. The margin overall is less.

CHAIR BONACA: You are presenting a result of an analysis here. You need to show that you require a pressure credit. In the SER, there is a discussion, the licensee has committed to terminate dry well cooling within two hours of entry into the safe shutdown procedure which would be used for a shutdown to fire. The analysis shows that this results in an acceptable available NPSH for the RHR pump.

So are you asking for credit? Or are you committed to do this modification to a procedure and so you don't ask for a credit?

MR. WOLCOTT: The curve that you're looking at here assumes that the dry well blower is stopped at two hours as it's in there. So that operator action is factored into the curve that you see here.

CHAIR BONACA: So you still need credit?

MR. WOLCOTT: Yes, absolutely.

CHAIR BONACA: This analysis shows that these results in acceptable available NPSH for the RHR pump, whatever that means. We'll talk about it later. It's not clear to me.

MR. WOLCOTT: So what the green line on this curve shows is again the containment pressure that's required to go into the NPSH equation so as to just equal the required NPSH for that particular time frame that's supplied by the vendor

As you can see, and again, the dotted line as atmospheric pressure at Browns Ferry, so time and area of which it's above the dotted line is the time and the magnitude that the containment overpressure is required as we define containment overpressure.

The main thing that drives the magnitude of this event is doing it with one RHR pump. That is the main difference between this event and previous events. And we also do not use core spray pumps in Appendix R, whereas the LOCA then had two pump curves on it, this only has one.

DR. ABDEL-KHALIK: So as a result of this analysis you have actually modified your emergency operating procedures so that you can terminate containment cooling within two hours of initiating event?

MR. WOLCOTT: That's correct. It wouldn't be the emergency operating procedures. It would be the emergency procedures that are specific to a fire.

MR. CROUCH: Tony, you want to talk about this and how we trained on it?

MR. ELMS: That's a two hour -- I'm Tony Elms, Operations Manager. That's a two-hour action limit. We validated these procedures. We already have persons in the areas and there's three ways that we can terminate this cooling. One is stop the RVCCW pumps from the control room, if control room abandonment is not required due to the fire. The next way is to go locally to the shutdown boards that they're fed from and trip the breakers. And the third way is to close the valve that puts the cooling water into the dry well from the control room. So depending on where the fire is at, there's three different ways that we can terminate this dry well cooling.

Our validation time has been within an hour for any of these three actions. Any way we try to isolate it, we can do it within an hour and it's a two-hour time limit.

DR. CORRADINI: May I ask then just so I'm clear, if you didn't do what you just said, the green would intercept and go above the red?

DR. ABDEL-KHALIK: According to this calculation.

DR. CORRADINI: Yes, I understand. I understand. I understand. Where the red is a lower limit. I understand. But am I understanding this correctly?

MR. WOLCOTT: The red would go into the green. It would terminate in the blowers, affects the red line. So it would cause the red to --

DR. CORRADINI: I'm sorry, excuse me. I said it backwards. I apologize. I apologize.

And I still want to understand the pump. You changed on how you apply the pump curve required in NPSH. You said it, but I didn't get it.

MR. WOLCOTT: Let me say what he said

simpler. In the previous LOCA analysis, we applied the vendor changes in time as step changes. And we just chose to do it at -- there's one step change in ten minutes, and one step change in eight hours. In this particular analysis, we did it as a continuum, basically, a very large number, very small changes. The vendor's thing is a curve is a function of time, so you can either do it in very coarse time steps which makes big changes, or you can do it in real small time steps.

This is a more refined analysis that was done in little tiny time steps.

DR. CORRADINI: Thank you. I understand that.

CHAIR BONACA: So anyway, this curve, the green curve includes the two-hour action of the operator.

MR. WOLCOTT: The red curve. The red curve is influenced by that action.

CHAIR BONACA: Okay.

DR. ABDEL-KHALIK: I'm sort of concerned about that. In a sense that this red curve is not reality. And what the operator will see in the control room may be quite different than what these results indicate. And yet, you're telling the operator according to this sort of calculation that we're doing with so many assumptions go ahead and terminate containment cooling, regardless of whether or not there's any indication of any possible problems with NPSH.

MR. WOLCOTT: That's correct. The Appendix R procedure is not symptomatic. It's a very prescribed situation, procedure to take care of a very degraded situation where a lot of equipment is assumed not be available. And so we take the minimum equipment we know we have protected and we just -- instruction just has us go out there and establish an alignment that we have pre-analyzed and know will work. And so these dry well blowers are just part of that.

We've also looked at the flip side to make sure that there isn't any problem terminating the dry well blowers, given that we're in this situation. There's injury conditions that we have to meet to even get into this thing and they kind of define the level of degradation you have to have already before you proceed down this procedural route.

DR. BANERJEE: What a scary thing to do though, I mean to terminate cooling when you've got a fire. I mean it's sort of counter-intuitive.

MR. SIEBER: Like flying an airplane with just a compass.

MR. WOLCOTT: The containment cooling is still progressing per the safety systems. None of our safety analyses take any credit for containment cooling -- dry well cooling I'm sorry, I used the wrong word there. So all of our safety analyses assume that dry well cooling is lost. We would not normally have any kind of a procedure we would intentionally terminate that. So this is kind of new to us and it is counter-intuitive. We thought about it a lot before we --

CHAIR BONACA: So it seems to me that this is a scenario for which you need the longest credit?

MR. WOLCOTT: Yes.

CHAIR BONACA: About 60 hours?

MR. WOLCOTT: Yes.

CHAIR BONACA: And for the LOCA, long term with sprays was 22.5 hours. I'm referring to Table 621 of your calculations for EPSS, the one you're representing here, right?

MR. WOLCOTT: Correct.

CHAIR BONACA: So you really need what, three psi credit for 60 hours.

MR. EBERLEY: This is 9.6 psi.

CHAIR BONACA: 9.6 psi. That's right.

MR. WOLCOTT: Any other questions on this?

DR. BANERJEE: There's no -- that green curve is simply given because you've got one RHR pump, is that it? There's no way to get it down?

MR. WOLCOTT: We can do -- we can take more realistic assumptions and get it down some, but Appendix R is normally done with mostly realistic assumptions, not all of the licensing basis conservatism, so we have to put in what we call design basis.

We didn't feel comfortable that we could change the analysis in a way that we get that down significantly and still do it in accordance with the rules that are attendant to Appendix R events.

Go to slide 11.

From here out, I'll stop talking about licensing basis analysis and start talking about realistic analysis. We did do some realistic analysis and some risk analysis on containment overpressure.

One of the things we did was compare credit for containment overpressure to the five principles that are given in Reg. Guide 1.174. Largely a comparison we were making here was the comparison between needing credit for overpressure and not needing credit for overpressure, not necessarily the difference in it, the amount of overpressure we need for uprate as opposed to 105 percent.

We found that containment overpressure meets current regulations. We reviewed all of this against Revision 3 which is the latest revision of Reg. Guide 1.82 which we take defines all the staff's current expectations about how to do this type of analysis. There is no regulation that says you can't do this, but it's consistent with defense-in-depth philosophy. What we would be worried about here is creating an inter-dependency between barriers. That's not appropriate. The barriers being a containment barrier and the fuel barrier.

There already is as inter-relationship between the integrity of the containment and the operability of the ECCS system pumps and as a consequence the cladding, the environmental qualification of the ECCS system depends upon the existence of the containment, its integrity. The water that they are pumping comes from the containment and we already require containment overpressure. This is just a greater magnitude. So we're really not introducing you to inter-dependency.

Maintenance of sufficient safety margins

-- the two graphs I showed you there kind of illustrate the amount of margin that we have in this analysis and I've discussed when we're talking about the graph that the amount of conservatism that's even buried within those curves that give us a high degree of confidence that things will work out at least as well as show in those graphs.

Very small risk increase. I have a slide in a minute that show the PSA results we got at looking at containment overpressure and the impact is monitored. In the way of monitoring we do a lot of things to monitor containment integrity. That would be the main thing we would monitor here because we're depending on local replace testing, each refueling cycle and at Browns Ferry we have a surveillance where we continuously monitor nitrogen usage in the dry well and have to address anything that's -- any leakage that's over 542 standard cubic feet an hour which lines up with our accident leakage, what we call L sub-A.

MR. SIEBER: You think a change in nitrogen usage will indicate much of a leak?

MR. WOLCOTT: Yes. Our criteria is meant to -- at normal containment pressures represent L sub-A which is the leak rate test. That's not very large.

MR. SIEBER: Yes. I could see that in a sub-atmospheric containment that in a regular pressure containment, you know, atmospheric containment, there's not going to be any leakage that you're going to be able to see.

MR. WOLCOTT: Well, the bulk of the containments say 1.1 psig on the outside and we tracked the nitrogen leakage close enough that leakage in the dry well part of the containment, that will show up.

In the torus part of the containment which is not above atmospheric necessarily, it would take longer to find. We will probably find it more from finding oxygen concentrations increasing than we would --

MR. WOLCOTT: What's the volume of the dry well? Do you know?

MR. CROUCH: Two hundred seventy-nine thousand cubic feet.

DR. BANERJEE: I guess the issue is really how well can you monitor leakage, that's really --

MR. WOLCOTT: It's the dry well part of the containment which is the more complex part of the containment as far as having penetrations in it. If we've got a leak that's in the neighborhood of L sub

A which is the same leakage that we assume when we do this analysis for NPSH, we'll find it within 24 hours.

We'll know that we have -- I shouldn't say that we'll find it, we'll know that we have it. We might have to physically find it -- it might take a little bit longer there. We'll know that we have a problem.

DR. BANERJEE: Just remind me, if you will, did we need such an extended period of containment overpressure for Appendix R in Vermont Yankee or not?

MR. WOLCOTT: Vermont Yankee --

DR. BANERJEE: Didn't need an Appendix R?

DR. CORRADINI: Does not require what?

MR. WOLCOTT: Doesn't require COP for an Appendix R event. They have two RHR pumps available or two RHR heat exchangers available.

CHAIR BONACA: Why do they have two of them? We have four heat exchangers and four RHR pumps, and you're assuming only one. Is it because of your licensee basis, the way it is now or what?

Why does Vermont Yankee only have two?

MR. WOLCOTT: I don't know the specific differences, but it would have to do with how things are laid out and how they've applied their fibers. I don't know the difference.

CHAIR BONACA: But these are limiting situations that you have. You're asking for the most credit for the longest time and you have to believe that the operator will, in fact, maximize pressure in containment which is somewhat counter-intuitive.

MR. WOLCOTT: Our durations and magnitudes are -- if you just take all the events together, our durations and magnitudes are not out of line with the rest of the industry.

CHAIR BONACA: What do you mean by that?

MR. WOLCOTT: I believe Vermont Yankee, for instance, in a LOCA is six hours and seven and a half psi.

DR. CORRADINI: Six according to the letter I have in front of me.

MR. WOLCOTT: This is not significantly different in magnitudes in duration, not out of line. This event, however, they just don't have or need it for an Appendix R event and we do. But if you take the events as a whole, just considering the differences in the plants and their -- this isn't out of line.

CHAIR BONACA: Okay. Sanjoy, do you have a question?

DR. BANERJEE: No, I was still pursuing your question. Why only RHR pump available out of four, RHR system? I really don't understand that.

DR. CORRADINI: Are the assumptions you have to make relative to the fire?

MR. WOLCOTT: Dave Burrell can probably address that best.

MR. BURRELL: In our Appendix R analysis we have basically 39 fire area fire zones within the three-unit plant and we assume for a fire in any one of those 39 areas, the whole area is instantaneously consumed by fire at T_{0+}.

And for the way our electrical distribution system is laid out internal to the plant, what equipment is fed from which boards, we have ensured that we had one set of equipment, one RHR pump available for all of the 39 fire areas and the analysis and the modifications that would be required to make two pumps available would be quite substantial and involving significant cable reroutes as well as reorienting the geometry of the layout of the electrical distribution system itself.

MR. WOLCOTT: We'll talk a little bit more about the realistic aspects of this in the next slide or two.

Slide 12.

We made a PSA model that looked at LOCA, ATWS and SBO events for the purposes of containment overpressure. And to do that model, we developed probability distributions for the various parameters that influence net positive suction head and the need for containment overpressure. That would be river temperature, initial suppression pool temperature, suppression pool water level or the volume inventory of water in the vessel in the suppression pool, and initial power level.

CHAIR BONACA: Why initial power level?

MR. WOLCOTT: All of our licensing bases or analyses are done at 102 percent of the licensed power level to account for the fact that there might be errors in calibration of instruments and stuff, so there's a probability distribution associated with --

CHAIR BONACA: 102 percent.

MR. WOLCOTT: Yes. And then on top of those things I named which govern the pool temperature and whether it's high enough to meet containment overpressure, then we also then added in the probability of containment isolation failure and the probability of having a pre-existing containment leak which would then affect the wet well pressure available curve and could make those two curves on the graphs I've shown come together. That's basically what we're looking at.

DR. CORRADINI: Could you repeat that again?

MR. WOLCOTT: Yes, we modeled the probability of containment isolation failure and the probability of having some pre-existing containment leak that would be large enough that it would take away the containment pressure that we are depending on.

DR. CORRADINI: And then there was a -- just so I clean it all up, there was a comment by the General Electric folks that humidity was important.

MR. WOLCOTT: Yes, it is.

DR. CORRADINI: So why don't I see it there as a variable that can affect this?

MR. WOLCOTT: We didn't do that one because --

DR. CORRADINI: Or is it linked?

MR. WOLCOTT: It's not a periodic variable. That's why, in other words --

DR. CORRADINI: It's linked to suppression pool temperature in some mechanistic way in your modeling?

MR. WOLCOTT: No. It's really linked to the thermodynamics of the dry well part of the containment and I would say that there's really two reasons we don't manipulate it. One of them we were manipulating physical parameters focused on determining what affects the water temperature. That's one of the reasons. The other reason is is that doesn't really periodically vary. We are taking assumptions that we know to be conservative. We don't actually measure dry well humidity on a day-to-day basis.

DR. CORRADINI: Okay, thank you.

MR. WOLCOTT: So what we were doing, the comparison we were making with this model here was to compare the dependence that we realistically have on containment overpressure versus a situation where there is no dependence, that RHR pumps and core spray pumps will always work irrespective of containment pressure, irrespective of containment temperature. In other words, it's a model that ignores the phenomena compared to a model that models the phenomena. If you test the risk, it's associated with taking credit for this to begin with.

DR. KRESS: This is a separate event, CDF event tree and I take it you go up or down on it according to some probability. If you go down on it, if these various things above take you into a net positive suction head below what's required at any time during the 24-hour period, is that --

MR. WOLCOTT: Mechanistically, the way it would work if the parameters such as river temperature and stuff are such that the curve, like I showed you, crosses the --

DR. KRESS: Crosses anywhere.

MR. WOLCOTT: Then we test to see if we have containment integrity. And if we don't, then the ECCS pumps would be assumed to fail in the model.

DR. KRESS: Yes.

MR. WOLCOTT: That's how it works.

DR. KRESS: Okay.

MR. WOLCOTT: So if the --

DR. KRESS: It's at that point in time?

MR. WOLCOTT: Dave is going to have to answer that question.

MR. MIMS: This is Bill Mims, TVA. We added two additional top events to our PRA model and that did exactly what J.D. We do not have containment isolation. At the beginning of the sequence you don't have low pressure ECCS.

DR. KRESS: Great.

CHAIR BONACA: Didn't you perform a sensitivity on the relative humidity in the dry well?

MR. WOLCOTT: Yes, we performed on the short term LOCA event, we performed the sensitivity analysis where we dropped the initial relative humidity from 100 percent which is our standard assumption in a LOCA to 50 percent which would not be our standard assumption. And that date -- we've used that to show if we just changed that assumption, that would give us enough containment pressure to cover or envelope the required NPSH by the vendor.

CHAIR BONACA: You left out the other conservatism and you modified that one.

MR. WOLCOTT: Yes. The staff will cover that in a little bit more detail. I didn't concentrate on that too much.

CHAIR BONACA: You said something before about you did not model humidity right before the long term. The short term you have, so --

MR. WOLCOTT: In the PSAs, we didn't vary the humidity as a probability distribution. It's certainly considered in these analyses. It's just not -- it wasn't assigned the probability distribution.

DR. CORRADINI: You didn't allow it to vary independently of the physical calculations.

MR. WOLCOTT: That's correct. So the result we got from that particular analysis for LOCA, ATWS and station blackout, delta CDF, delta LERF was 2.4 times 10^{-8} per year. That would be an effect of depending on containment overpressure for those events as opposed to having some other way to take care of it that did not require containment.

DR. CORRADINI: The reason -- maybe you said it and I missed it. The reason they're the same surprises me and the reason is because they're exactly the same because?

MR. WOLCOTT: It's because in this particular analysis any success path -- I may not be saying this right, but the success path always has containment in it and to fail you have to -- to fail this particular analysis, you've got to fail the containment because that's what's making the ECCS work and so that's the reason why in this particular analysis they are the same. Somebody else might be able to say that better.

DR. CORRADINI: Can I just say it back to you? Is that they're one and the same, what you just said is if I fail, if I go into some kind of core degraded core state I have a failed containment simultaneously.

MR. WOLCOTT: Yes.

DR. CORRADINI: The failed containment is causing that in this analysis?

MR. WOLCOTT: Yes.

MR. MIMS: This is Bill Mims. That's correct. If you -- in order to not have containment overpressure, you would have to have some failure containment which means there's a hole. So in the delta, in the CDF is mapped or assigned directly to LERF.

DR. CORRADINI: Thank you.

MR. WOLCOTT: Slide 13. The final slide I wanted to discuss a little bit, what realistic analyses and what realistic differences figure into these four events. And what I would conclude from this is it takes a combination of unrealistic assumptions, in one way or another, to get us to a position where we need containment overpressure in these events.

For example, for the LOCA analysis, we have to have specific single failures that affect the RHR system before we need containment overpressure. If I have four RHR pumps or both trains, I do not need containment overpressure. So I'm calling that -- that's being driven by assumption of a particular set of single failures that happen to get have other train.

CHAIR BONACA: That's also long term?

MR. WOLCOTT: It's long term.

DR. BANERJEE: Because you won't have enough RHR. You will need the core spray.

Because you get a lower suppression pool temperature.

MR. WOLCOTT: That's correct. That lowers the suppression pool temperature.

For an ATWS event, if we analyze the power generation phase of that event with a best estimate code, we do not need containment overpressure. There isn't as much power generated and put into the containment and we would not need containment overpressure --

DR. BANERJEE: This is the Odin.

MR. WOLCOTT: The licensing basis code would be Odin.

The best estimate code that we looked at was TRACK. DR. BANERJEE: The best estimate code is TRAKG.

MR. WOLCOTT: That's correct. So Odin is --

DR. BANERJEE: Odin is the licensing code.

MR. WOLCOTT: It's known not to be very realistic when it's modeling this type of event.

DR. BANERJEE: What happens if you used Odin?

MR. WOLCOTT: The curves that we use as our licensing basis do use Odin and they do show that we require containment overpressure.

DR. BANERJEE: For how long?

MR. WOLCOTT: What's the duration?

DR. BANERJEE: Is it in here?

MR. WOLCOTT: I don't have a slide on it.

DR. BANERJEE: Just a verbal.

MR. WOLCOTT: About an hour and a half.

DR. BANERJEE: And it's after two or three psi.

MR. WOLCOTT: 1.9 psi for about an hour. Moving on to the next event, talked about this a little bit.

DR. BANERJEE: TRAKG used to have problems with ATWS. Did you get rid of these problems now? Who did this magic?

(Laughter.)

MR. JACOBS: Randy Jacobs, GE. What problems --

DR. BANERJEE: All sorts of problems.

MR. JACOBS: We do have an updated version of TRAK that we've been executing TRAKG-04 and it's been much more robust in handling.

DR. BANERJEE: What did you do, put more damping? Anyway, okay.

MR. JACOBS: We've got another TRAKG expert here to maybe answer some of that.

DR. BANERJEE: It creates a diversion.

(Laughter.)

MR. ANDERSEN: This is Jens Andersen from Global Nuclear Fuel. I'm not sure what the specific problem that you're referring to is, but clearly the conversion that we have with TRAK that's consistent with the Panic 11 kinetics model is performing quite reliable for ATWS calculations.

DR. BANERJEE: Okay, thanks.

MR. WOLCOTT: For the Appendix R event, as I said earlier, that's driven largely by being down to one pump of heat exchanger. If we had two pumps of heat exchanger we would not need containment overpressure.

In addition to that, loss of the normal heat sink is a major driver in this. The fires that we have that would affect the RHR pumps would not affect the balance of plant. However, the Appendix R rule has us assuming a loss of off-site power that's unrelated.

If we had a normal heat sink, we wouldn't be having this conversation because we wouldn't be heating up the pool. So there's a lot of things inherent in the Appendix R analysis that define the event to start with, that kind of pull us here that are not really a very realistic --

DR. ABDEL-KHALIK: And you feel like you can give the operator firm instructions to terminate containment cooling after two hours.

MR. WOLCOTT: There are firm instructions. Once we realize that -- once we meet the entry criteria for having this level of degradation in the plant, if we don't meet that entry criteria that is if we still have the balance of plant and we're still cooling down to that, you would never enter that procedure, you would never be told to do anything like that. You just cool down the normal way and we wouldn't need this.

So yes, once we --

DR. ABDEL-KHALIK: What are the other conditions that have to be present in order for the operator to take that action?

MR. WOLCOTT: Tony, can you do that one?

What are the entry conditions?

(Pause.)

If you want to give him a minute to look at that, we can just talk about the next one while we're doing it.

I'll just move on to the -- to how that fits into the station blackout. We didn't put the graph up there, but the station blackout, the need for overpressure there is driven strictly by the fact that the way we apply the event analysis, you have no AC power and no heat removal at all for four hours. And if you don't remove any heat, something has got to give.

So if it's not very realistic, given that we have eight diesel generators that there's no connectable between units, that we would really be caught for a full four hours without any AC power. If we were able to get some AC power back and RHR pumped back at three hours, we would not need containment overpressure.

So again, that event is defined in a very severe way and that's what's driving us to do this.

MR. ELMS: I am Tony Elms, Operations Manager. Entry conditions for our site shutdown instructions, first is Unit 2 and Unit 3 is greater than atmospheric pressure and the magnitude of the fire has the potential to affect the safe shutdown capacity as identified by one multiple failures, spurious actuations of systems and components have occurred or erratic or questionable indications on numerous main control room instruments have occurred or multiple trains or channels of safety-related equipment are threatened by the fire.

So those are the things that would cause us to enter into the AOIs, I mean SSIs, excuse me.

DR. BANERJEE: Thank you.

MR. WOLCOTT: That concludes our presentation.

CHAIR BONACA: Well, three versus four hours, what is your basis for Browns Ferry, four hours?

MR. WOLCOTT: It's four hours. The unit has to cope for four hours with no AC power.

CHAIR BONACA: I think we need a break.

MR. WOLCOTT: Yes.

CHAIR BONACA: Thank you for your presentation and we'll go to break until 4 and then we have NRR presentation.

(Off the record.)

CHAIR BONACA: Okay, let's go back into

session. We now have a presentation from the staff regarding containment considerations.

MR. LOBEL: Good afternoon. My name is Richard Lobel. I'm a Senior Reactor Systems Engineer in the Containment Ventilation Branch in NRR. And I'm here today to present the results of the NRC Staff Review of the Browns Ferry Containment Safety Analyses of Power Uprate Conditions.

I'll give a brief overview of the results of our review and all the containment review areas and then I'll provide more detailed discussion of the issue of crediting containment accident pressure for NPSH for the Browns Ferry pumps.

Let me just make two comments before I start I was asked to make. The first was about the comments on the TRAKG code. I just wanted to make it clear that the comments that the licensee made and I thought the licensee made it clear, was that these were just sensitivity studies and they didn't play any role in -- they aren't part of a licensing basis and they didn't play any role in the staff approval of the Browns Ferry power uprate for five percent.

The other comment was I wasn't going to address this specifically unless there was a question, but I thought it might be useful since this initiative has been discussed with ACRS at every meeting we've had on the subject is that we are looking at -- we and the industry are looking at ways of making this analysis more realistic and quantifying the uncertainty in the analysis.

We had a meeting in October with the BWR owners group where we discussed a little bit about what would be done. That meeting was mostly a scheduler meeting and a meeting to talk about regulatory business type affairs, not the technical meeting. But it's my understanding that BWR owners group is currently working on this method and the staff, now that you're done with the Browns Ferry review and some other work is going to start the next revision of Reg. Guide 1.82 which will incorporate, which will make the Reg. Guide risk-informed on the subject of containment accident pressure.

And hopefully, we'll be able to get some input from the BWR owners group and do some work on our own on the subject of more realistic analysis where we quantify the uncertainties in the significant parameters.

We were talking with BWR's owners group about a possible submittal of the first stage of the review around September 2007. That's a very tentative date, but just to give you an idea of the time frame and speaking for them, although I shouldn't be, they might be persuaded to give a little presentation on their progress at some point before then if the Committee is interested.

CHAIR BONACA: This is the approach we discussed for Vermont Yankee which was encouraged by --

MR. LOBEL: It was encouraged at Vermont Yankee and it was also encouraged when we talked to the Committee about Reg. Guide 1.82.

This slide lists the review areas specified in the NRR review standard for power uprates. Under containment functional design, the staff reviews the peak pressure and temperature analyses for the primary containment and for BWRs, the response to hydrodynamic loads.

These result from a blowdown of the reactor coolant system into the suppression pool following a design basis LOCA or the discharge of reactor steam into the suppression pool from the main steam relief valves through the quenchers and the suppression.

The analyses were performed by the licensee using computer methods previously approved by the NRC. These include the LAM code for vessel blowdown, the M3CPT code for the peak containment pressure and temperature as a result of the LOCA and the Super Hex code for long-term suppression pool temperature and containment dry well and wet well temperature.

The peak calculated dry well pressure was 48.5 psig and the dry well design limit is 56 psig. So there's margin between the conservative calculated peak and the design limit.

The suppression pool temperature is 187 degrees Fahrenheit and the design limit is 281 degrees Fahrenheit. The hydrodynamic loads were all within establish limits.

The subcompartment analysis for Browns Ferry consists of calculating the pressure difference between the pressures in the space between the vessel and the biological shield and the pressure in the rest of the dry well and this ensures that the peak pressure difference doesn't exceed structural design requirements.

For Browns Ferry, the allowable pressure difference was 19 psid. The calculated peak pressure difference is 2.6 psid. So there's ample margin for that calculation.

The mass and energy release into the dry well is calculated using acceptable methods that I just mentioned and --

CHAIR BONACA: I think this slide -- okay. Appreciate it.

MR. LOBEL: The mass and energy release into the dry well is calculated using acceptable methods that I just mentioned and results of this calculation of the mass and energy are used for the pressure temperature and hydrodynamic loads valuations.

Combustible gas control deals with generation of hydrogen and the steps taken to ensure that the concentration of hydrogen remains below the combustible concentration. This is done by inerting the containment with hydrogen gas and the operation of the containment atmosphere dilution system, CADS. There were no review issues in this area for the five percent power uprate.

Containment heat removal for BWR deals primarily with cooling the suppression pool and it also, because of the way the standard review plan is structured, deals with the issues of net positive suction, that's for ECCS pumps and I'll discuss that in the remainder of my presentation.

There were no issues raised in the review of the secondary containment.

Next slide.

We've covered a lot of this already, so I'll try to spent more time on the points that weren't discussed. The treatment of net positive suction head for the Browns Ferry ECCS pumps was a big part of the staff review, particularly for the RHR for spray pumps. TVA meets the pressure both for LOCA and the non-LOCA events that were already discussed at this station blackout in Appendix R.

The licensee applied pump vendor curves for reduced required NPSH and these curves provide additional NPSH margin over the typical values of required NPSH.

Can we go to the backup slide?

(Pause.)

This didn't turn out very well, but this slide comes from the Salzer report and it's not necessary to read any numbers, but just to give you an idea of what the curve looks like, it's NPSH which is really required NPSH on the Y axis and operating hours on the X hours and a logarhythmic scale. And this is the pump vendor's judgment of the required NPSH that would be acceptable for these operating times and it's parametric with pump flow rate.

So these are the curves that the licensee incorporated into the NPSH analyses and the top horizontal line is what was referred to before as the 8000 hour operating time. So the pumps would be assumed to be at a required NPSH below the maximum value for a limited amount of time.

And like I said before, that's really based on the pump vendor's experience and judgment from testing, not just at Browns Ferry pumps, but his whole body of experience with centrifugal pumps.

So there's one case where the containment atmosphere does not supply enough pressure for the NPSH to be satisfied.

MR. LOBEL: Well, let me be clear.

MR. SIEBER: That would be yes, right?

MR. LOBEL: I'll get to it later. This curve was included in all the NPSH calculations. Even including this curve and credit for accident pressure for the short-term LOCA that wasn't enough.

MR. SIEBER: Right.

MR. LOBEL: And there was a prediction that the pump would cavitate or at least would --

MR. SIEBER: Well, the question is will the pump fail?

MR. LOBEL: Right, and I'm going to talk about that.

DR. BANERJEE: Am I right in reading this curve that -- these curves that at higher flows you have less of a problem than at lower flows?

MR. LOBEL: No, at higher flows, you need more -- the NPSH -- the required NPSH is higher. So that would reduce the margin between the available and the required.

Next slide.

DR. BANERJEE: What do the pump characteristics basically on these flows look like? do you have an idea? Like is the solid line at the fire end of the characteristic or the head developed is fairly low?

You have the head versus Q curves for this?

MR. LOBEL: I don't have them with me.

DR. BANERJEE: I don't remember seeing them in the report.

MR. LOBEL: I think they're in the Salzer report.

DR. BANERJEE: Are they?

MR. LOBEL: Yes. And there are curves in the FSAR too, I think. I don't know if they're the same curves.

And the curves would probably be curves from the pump vendor, so they may not be the latest Browns Ferry values, but they should be curves.

DR. BANERJEE: What is the curve that is being required, for example.

MR. LOBEL: This is for the RHR for the long term. I'm sorry, for the short term. The pumps that are pumping into the broken recirculation route are at 11,500 GPM. The pumps pumping into the intact loop are 10,500 GPM. And after the long-term, after the operator thrives it's the 6500 GPM.

DR. BANERJEE: They require about 21 feet NPSH? Sorry, no, about 27 feet or something, 26?

Between 26 and 30 or something like that, right?

MR. LOBEL: Whatever, the numbers are.

DR. BANERJEE: That's how they establish that 31 feet or something.

MR. LOBEL: Okay, Browns Ferry Units 2 and 3 currently credit accident pressure, I think we already talked about that.

The RHR pumps have several safety functions. Let me just list them again. They're the low-pressure coolant injection pumps. They cool the suppression pool and they also provide the wet well and dry well spray flow, so that's one of the reasons that there's this short-term and long-term split because originally the RHR pumps inject into the vessel and after the ten minutes, then by then the vessel, the core should be covered. There still is core spray flow into the vessel so if all the conditions are met, the operator can defer the RHR pumps to the suppression pool cooling mode.

I think we went through short-term and long-term enough. I mentioned the three events.

I included this, this is a summary of a table in one of the licensee's calculations just because the question always comes up about what the margin was and how long containment pressure was needed and the amount. So CS is core spray. RHRIL refers to the intact loop. This is for the short term where one train is injecting into the intact loop of the recirculation lines and the other two RHR pumps in the other train are injecting into the broken loop.

We've already covered ATWS, Appendix R and station blackout. The dry well coolers are terminated after two hours. Appendix R event has the maximum amount of pressure required and the longest duration time because of the assumption that there's only one

RHR pump available and one heat exchanger.

DR. POWERS: Have you thought or looked quantitatively at the probability of maintaining the containment intact in nine hours?

MR. LOBEL: We can talk about that a little later, but -- well, not during the accident. I wasn't going to talk about that, but could we hold that off? I'm going to talk about containment integrity. Can we hold it off until then? Or we can talk about it now.

(Laughter.)

DR. POWERS: If it's forthcoming, I can wait.

MR. LOBEL: The usual design basis analysis always assumes containment --

DR. POWERS: I'm not interested in what you assume.

MR. LOBEL: The Appendix R and station blackout and ATWS events have criteria that have to be met, one of which is containment isolation is maintained and containment integrity is maintained. And that's done in terms of limits on containment pressure and for station blackout, a demonstration that losing all AC power isn't going to open up the containment in some way.

The containment is leak tested, and ILRT is done. Every so often, according to Appendix J, the --

DR. POWERS: None of which are done at temperature.

MR. LOBEL: I'm sorry?

DR. POWERS: None of which are done at temperature?

MR. LOBEL: Right. And in Appendix J there's also a requirement in 10 CRF 50.55A that visual inspections and other inspections are done of the structure for degradation.

DR. POWERS: You're not helping me.

MR. LOBEL: I'm sorry?

DR. POWERS: Not helping me.

MR. LOBEL: Other than, well, let me mention one other thing I've mentioned before. I did mention the peak containment pressure is much less than the design pressure.

DR. POWERS: Yes, but that's not where it is going to fail, is it?

MR. LOBEL: Well.

DR. POWERS: It's not going to fail from overpressure. It's going to fail from leak failure, seal failure, or something like that.

MR. LOBEL: The seals are supposed to be environmentally qualified. They are supposed to withstand environmental qualification temperature that's --

DR. POWERS: The road to hell is lined by things that are supposed to not fail, isn't it?

MR. LOBEL: I'm sorry?

DR. POWERS: The road to hell is lined by things that were not supposed to fail.

MR. LOBEL: I can't give a -- if you're looking for a guarantee that nothing bad will happen --

DR. POWERS: What I'm looking for is somebody looked at the probabilistics on this. Everything you said is true and for a design basis, accident, yes, those assumptions are made and we go to elaborate lengths to assure through Appendix J and a variety of other things that those assumptions are valid. But the truth is there is still some probability of failure. And what I'm looking for is what is that probability?

MR. LOBEL: Well, there is a fragility curve in the PSAs, and I don't know off-hand whether that it is a temperature or not. It's not.

DR. POWERS: Yes, I mean it's an overpressure failure. That's not where those things are going to fail. They're going to fail in two ways. Well, one is there was a mistake made. You can argue that that's hard to have happen because of the inerting requirement. You've got some positive feedback here.

MR. LOBEL: Well, there are a lot of checks that are done, too.

DR. POWERS: The other way it is going to fail is that because of the thermal and radiation environment you have that material degraded through a stochastic event. The question is what is that probability?

MR. LOBEL: Well, also most of the containment isolation valves, if not all, and the airlock doors are double-sealed, redundant valves, redundant seals, so even if the first seal fails, it would see the high temperature. The second seal may not see that high temperature or as high a temperature. And it is redundant, so that is another level of safety. I can't sit here and tell you that you know there is 100 percent chance that nothing will ever happen. I think that we have considered the possibilities within the regulations and looking at it from a probabilistic safety point of view, too, looking at different events and assessing the risk. I don't know what more I can say.

MR. SIEBER: Well, maybe Marty can tell us what the overall risk of all of these cases where containment overpressure is required.

MR. STUTZKE: It's Marty Stutzke from the staff. To be specific, the loss of containment integrity that was examined by the risk assessment was for existing leaks that were not detected. The actual failure to achieve containment isolation, it's to my knowledge that there is no time sensitive failure modes in there like the reliability of the seals or things to be considered.

As Rick pointed out, I mean, we don't normally model MPRA past the failure modes like motor operative valves spuriously open and things like this. You would have to get several of them open to be in a problem. With respect to seal failures, as Rich points out they are environmentally qualified. I would offer the radiation environment is small at this point in time. It's prior to the core damage.

MR. SIEBER: On the other hand, the risk from all accidents that require containment over pressure, the function is what, ten percent of the total risk?

MR. STUTZKE: Yes, that's correct, roughly. I have some slides that I will present after Rich, but the contribution to the total CDF from containment accident pressure credit is about ten percent, using some pretty bounding assumptions.

CHAIR BONACA: What about the issue of just one RHR pump out of four? This is not characterized as a single failure. It is a failure assumed, I mean, some implications. I'm trying to understand the combination, the conservatism associated with the combination of assuming one RHR and loss of containment.

MR. LOBEL: The way in general Appendix R analyses is done, is you divide the plant into fire zones, and you assume a fire in each zone wipes out all the equipment in that zone. Then whatever you are left with, is what you have to bring the plant to a safe condition. In the case of Browns Ferry, for their worse case, they end up with one RHR pump and one heat exchanger and one RHR service water pump. The RHR pump is, the flow goes through the heat exchanger and the RHR pump is injecting into the vessel. It's cooling the vessel and cooling this suppression pool with one heat exchanger. That is what gives the high temperature.

DR. POWERS: The challenge you have with fire analyses and why the assumption that a fire zone, all the equipment in that zone fails, may not be conservative. Fire is a very peculiar beast. It can cause equipment to fail or it just doesn't operate and it can also leave equipment that operates, but operates badly. That can be a worse situation, equipment that just doesn't operate.

MR. LOBEL: Well, I don't know that much about Appendix R, but it is my assumption that that is looked too, so that's part of the analysis --

DR. POWERS: You characterize the Appendix R analyses correctly.

MR. LOBEL: But I mean the business of shorts and associated circuits and all of that.

DR. POWERS: That's another aspect of it. That is to assure that you have one way of cooling down the plant. Here we're asking can you keep the containment at this pressure that we need, which is not very much pressure, but we need it for a long time. That's a different analysis. That isn't done in Appendix R.

MR. LOBEL: Well, you also have to consider too that there is another consideration, and that is the operator. The operator would be monitoring the NPSH. I'm getting all the way through my presentation, but the operator is going to be monitoring the behavior of this pump. If he sees that there is a problem, he can throttle the flow more than what is assumed in this analysis. That might still be enough to accomplish what the RHR pump needs to do, but he wouldn't be cavitating any more.

Or there's ways of putting water into the containment, especially at Browns Ferry with connections to the other units. There is ways of putting the water into the containment or into the suppression pool or not cooling the suppression pool with the pumps from another unit, because that wouldn't work. But there may be ways of adding water to the vessel, so maybe the RHR pump wouldn't have to --

DR. POWERS: The problem with those kinds of arguments is they invite the comment that if the operator can make things better, there's also some chance that he will make things worse.

MR. SIEBER: Before you leave that chart, the third one down, I presume, is the one you are talking about. In LOCA short term with negative minimum and NPSH margin, which means it is cavitating pretty big time. If nobody does anything, what happens?

MR. LOBEL: If nobody does -- well, the way the analysis works is the short-term analysis is for ten minutes and then that's the end of the analysis.

To answer your question --

MR. SIEBER: What if the pump fails?

MR. LOBEL: Well, we're saying the pump won't fail for four minutes that it's cavitating and then that would be ten minutes. And if the operator hasn't throttled the pump before then, the operator can throttle the pump for ten minutes. And when he throttles the pump, the pump won't be cavitating any more.

MR. SIEBER: And if he doesn't, does that mean that the pump continues to cavitate and if so, for how long?

MS. BROWN: Bill, would you guys like to discuss that a little better, since you guys have --

MR. WOLCOTT: J.D. Wolcott, TVA. The answer to that question would be the particular pumps that have the negative NPSHR are having no function whatsoever in that alignment. And so if no one ever did anything with them, they would possibly fail after a while, but if no one realigns them into a useful mode, then it wouldn't matter.

MR. LOBEL: I was going to say if the pumps that are -- the reason this is important is that the pumps that are cavitating -- there are two pumps that are cavitating and two pumps that aren't cavitating. For the short term, it doesn't matter because the pumps that aren't cavitating are supplying flow to the vessel.

Like J.D. said, the pumps that are cavitating aren't doing anything and you don't care. But then when you go to the long-term analysis, if you take a single failure of the pumps that were not cavitating --

MR. SIEBER: One fails.

MR. LOBEL: One failure. Then you're -- well, it takes out both pumps and the train. You fail one train for whatever reason.

Now you depend on the pumps that were cavitating that were in the suppression pool. So it's important that those pumps --

MR. SIEBER: Be operable.

MR. LOBEL: Be operable, survive the four minutes of cavitation.

MR. SIEBER: So in that case, you're actually relying on the operator to see the amps swinging and the floats swinging which gives them a clue that there's cavitation going on.

MR. LOBEL: Right. Plus the high flow rate to begin with.

MR. SIEBER: Good luck.

MR. LOBEL: Well --

MR. SIEBER: There's a lot of instruments on those boards.

MR. LOBEL: Yes, but this is one of the more important ones, the operation of the ACCS pumps. And I've been told by operators in the past that ten minutes is really more time than is needed to throttle back the pumps. The containment assumption is really very conservative.

MS. BROWN: Bill, did you have anything else to add?

MR. CROUCH: Yes, the action to throttle the pumps at ten minutes and realign them, that's procedurally driven to do that. They're not assuming that the realignment happens because the operators detect the cavitation. They're being procedurally driven to realign the containment cooling mode.

So it will happen even if the pumps were not cavitating.

MR. SIEBER: Okay.

MR. LOBEL: Next slide. This is what we just talked about.

CHAIR BONACA: Because actually, the case we're making is that probably they would not be cavitating.

MR. LOBEL: Well, I'm getting to that.

(Laughter.)

CHAIR BONACA: Well, I'm saying that again --

MR. LOBEL: Let me -- let's go to the next slide.

This is the picture of what's going on in the short term and the top there is the wet well pressure, that's the pressure that's calculated, conservatively calculated to be available. The suppression pool temperature is the increase in curve, a solid line increase in curve. The RHR intact loop in the core spray need containment pressure, but you can see that they're below the containment pressure that's available and so although they're crediting containment pressure, they're also crediting this required NPSH pump vendor curve. They won't cavitate. They're not predicted to cavitate. The RHR broken loop is predicted to cavitate. This is the picture of what was on the --

MR. SIEBER: That ends in 600 seconds, but that's when you ended the calculation.

MR. LOBEL: That's when the calculation ends, but like J.D. said --

MR. SIEBER: That could be going on forever.

MR. LOBEL: No, well, what J.D. was just saying, the operator would at that time switch over to suppression pool cooling any way. So the flow rate would go from the flow rates in here which are 10,500 and 11,500 down to 6500 GPM.

CHAIR BONACA: Those are pressures, RHR and broken loop.

MR. LOBEL: Yes, that's --

MR. SIEBER: You have to talk into mic.

DR. BANERJEE: There's a pointer next to you.

Is the wet well pressure the lowest possible pressure, the lower bound?

MR. LOBEL: Yes. It's conservatively lower bound pressure.

DR. BANERJEE: So what are the conservatisms in there?

MR. LOBEL: You assume that the suppression pool temperature is at its tech spec maximum to start with. You assume that the decay heat is decay heat value plus two sigma uncertainty. You assume that the reactor power is at 100 percent plus 2 percent for instrument uncertainty, so the reactor power is 2 percent above the licensed thermal power.

DR. ABDEL-KHALIK: I'm sorry, that's the opposite direction. All of these uncertainties give you a higher pressure.

MR. LOBEL: I'm sorry, I'm talking about raising the suppression pool temperature. Okay, for --

DR. BANERJEE: But that's for suppression pool temperature.

MR. LOBEL: So the suppression pool temperature is high. For the pressure, you assume the containment volume is conservatively large. You assume that the humidity, relative humidity is 100 percent because that minimizes the amount of air in the containment and minimizing the amount of air in containment minimizes the pressure.

Let's see, there isn't any cooling yet for the short term, and there's --

DR. BANERJEE: But it all depends a lot on the discharge rate, what's coming out of the --

MR. LOBEL: Yes, sure.

DR. BANERJEE: How do you make that --

MR. LOBEL: You do a calculation that would be -- well, I'm not sure. I'm not sure for BWRs. I'm not sure how -- maybe GE or somebody can answer that. I can answer for PWRs, but not BWRs.

DR. BANERJEE: How do you make the energy input into the containment conservative?

Conservative from the point of view of the pressure?

MR. RAO: Would you repeat the question, please?

DR. BANERJEE: How do you make the energy input into the containment for the purposes of calculation of the pressure conservative?

MR. RAO: There is no specific input for to make the pressure conservative. The pressure conservatism comes from the initial conditions that are assumed for the dry well and wet well by way of dry well and wet well pressures being minimized and the relative humidity being maximized.

DR. BANERJEE: The same input that raises the -- if you go to that curve. The reason that pressure is high is because of the energy input, right?

MR. RAO: Yes, this is as a result of the blow down and the energy from the fuel. This is correct.

DR. BANERJEE: Well, how do you make that conservative? You want to minimize -- you're trying to establish a lower bound. You're not helping me right now.

MR. LOBEL: I'm not sure you do.

DR. BANERJEE: I thought you were trying to establish a lower bound.

MR. LOBEL: You're establishing a lower bound for the pressure and an upper bound for the suppression pool temperature, but the suppression pool temperature has a much larger effect on the NPSH and so --

DR. BANERJEE: I'm just trying to establish that line there.

MR. LOBEL: Well --

DR. BANERJEE: Is that line likely to be 20 percent lower or not?

MR. LOBEL: You could do the calculation, I'm sure, in a way to make it 20 percent lower.

DR. BANERJEE: Well, if it was 20 percent lower, and it was 100 or 110, what would happen?

MR. LOBEL: Why would you need to do that calculation?

DR. BANERJEE: Let's say the pressure is down by 20 percent.

MR. LOBEL: But why?

DR. BANERJEE: Because you've done something wrong with your calculation. Let's assume that I can find a way to calculate this which is lower. I'm asking you about the energy input and I'm not getting a straight answer.

MR. DeLONG: Rich, where do we get the mass and energy inputs from?

DR. BANERJEE: Where do you get it from?

MR. DeLONG: Which code are they coming from for the break?

MR. LOBEL: I'll let GE answer.

DR. BANERJEE: GE doesn't answer that. We've asked them once.

MR. LOBEL: The mass and energy for the short-term calculation comes from LAM, isn't that right?

MR. RAO: No, it's from Super Hex.

DR. BANERJEE: It was ten seconds they told us before.

MR. LOBEL: We're mixing a whole bunch of stuff together.

DR. BANERJEE: Can you just --

MR. LOBEL: One thing at a time. The ten seconds was for a peak pressure calculation. That's to determine whether the peak pressure in the containment is less than the design pressure. We were talking about that now.

DR. BANERJEE: Yes, that was with LAM.

MR. LOBEL: Super Hex is used to calculate the mass and energy release for the NPSH calculations. It's not necessary, there's no requirement that every variable be made conservative and in fact, like I said, the suppression pool temperature is a much more important variable than the pressure because the suppression pool temperature affects the vapor pressure which is very nonlinear. So the suppression pool temperature has a much bigger effect. So you're not trying to minimize suppression. In that case, you're trying to maximize the energy that's going into the dry well and into the suppression pool.

DR. BANERJEE: Now, let me ask you the question. Imagine that the temperature curve is fixed. You've established the highest temperature curve, okay? We accept that.

Now I'm asking you how do you establish that the pressure is the lower bound? This is a question that came out before. We kept asking you about this before. Now imagine that was 20 percent, then you'd a much more extended period of cavitation.

MR. DeLONG: Is there biasing in Super Hex?

MR. LOBEL: The pressure is minimized by using a larger than nominal volume, what did I say before, the suppression pool level is a minimal level so that there's more space for the steam and the nitrogen. I'm sure there's others I'm not thinking of right now -- the humidity, the relative humidity is 100 percent.

DR. BANERJEE: But the main thing that determines the pressure is the energy input.

MR. LOBEL: It's more important to maximize, or at least use a nominal energy input to maximize the suppression pool temperature than it is to maximize the pressure.

DR. BANERJEE: Right.

MR. DeLONG: So we bias the containment variables. Do we do anything to bias the input that we get or is that a nominal calculation?

MR. LOBEL: The input?

MR. DeLONG: The mass and energy.

MR. LOBEL: The power is 102 percent.

MR. DeLONG: Okay.

MR. LOBEL: The decay heat is two percent above the nominal value. For the short term, there isn't a whole lot more, at least that I'm thinking of right now. The initial temperatures of the water and the air are maximized. So things are put in the direction that gives them the most conservative calculation.

DR. BANERJEE: So let me paraphrase what you're saying.

MR. LOBEL: Yes.

DR. BANERJEE: As far as your calculation inputs are concerned, you're trying to get the highest suppression pool temperature.

MR. LOBEL: Right.

DR. BANERJEE: But you're not necessarily getting the lowest wet well pressure.

MR. LOBEL: Well, when you put it that way, I'm not getting the highest suppression pool temperature either. I mean I always make it higher. I could take decay heat plus three sigma and that would give me a higher temperature than decay heat plus two sigma.

DR. BANERJEE: So why did they choose two sigma?

MR. LOBEL: Because two sigma is a usual

uncertainty and 95 percent uncertainty for regulatory requirements, regulatory analysis.

DR. BANERJEE: So what about taking two sigma on something else?

MR. LOBEL: Well --

MR. DeLONG: I think that's what we're going to get into when we work with GE on specifying the uncertainties and assigning distributions and -- that's the goal of moving away from what appears at times to be an arbitrary pushing of variables in one direction or the other. We do this two ways. We either put all the energy into the containment or we put all the energy in the water which is very confusing to people.

So I think the real answer to your question is going to come when we can establish a more systematic way of doing things as part of the 1.82 Reg. Guide revision. This is the best we can do for now.

DR. BANERJEE: I guess I was under the wrong impression and maybe the rest of the Committee was as well, which was that you made a set of assumptions which would give you the two sigma or whatever, the highest suppression pool temperature and that you then made a separate set of presumptions which would give you the lowest, lower bound on the wet well pressure. This was the impression I had.

Let me ask the rest of the Committee if that was the impression they had. Definitely, this is what I came away with and that's not what you've done. If you had a wrong impression thank you for correcting it.

MR. LOBEL: There is only one calculation, so you try to do -- you try to minimize the pressure and maximize the temperature, but you're only doing one calculation. You could, I suppose, do a separate calculation and calculate the very minimum pressure --

DR. BANERJEE: That was the impression we had, at least I had.

MR. LOBEL: Okay, well, I'm sorry.

DR. BANERJEE: What you've done is one calculation in which you have chosen to maximize the suppression pool temperature and you've taken whatever pressure it is with some initial conditions which were a little bit conservative, 100 percent humidity, whatever.

MS. BROWN: I'm sorry. I think it's TVA who made the assumptions regarding those values.

DR. BANERJEE: All right, TVA did.

MS. BROWN: Maybe the question may be

better put to TVA as they made those assumptions.

MR. CROUCH: Hey, Eva. Let's J.D. talk about what for a second.

MR. WOLCOTT: It still remains true that there are essentially two separate things calculated, trying to force the pool temperature higher with assumptions and just force the containment pressure lower with assumptions. The things that drive that that are variables that we fool with are relative humidity. Rich said what some of them were. Initial temperature in the dry well, all of which govern how much noncondensibles are in there to start with for the containment pressure.

Now we do though -- what we don't do and I think this might be what you're getting at, we don't look at things like power level. We're doing these -- we're doing the suppression pool assuming the initial power is 100 percent and the containment pressure assuming 100 percent power and not at some derated power level, for instance, because as we start to reduce some of those things like what the operating state of the plant is, of course, the torus temperature, the pool temperature will go down along with the containment pressure.

So some of the things we had to pick

initial starting states and I think that might be the nature of what your question is.

DR. BANERJEE: I can imagine a scenario where you discharged more hot water than steam into the containment to start with. If you did that, you would discharge less energy, obviously, because steam is what contains the energy.

So in that case your pressure might be lower and you might get a lot of hot water because of the specific heat. I don't know. I haven't actually sat down and done these calculations, but I can imagine scenarios where the suppression pool temperature will be high and the pressure could be lower. What I'd thought you'd done is you've given us the upper bound of the suppression pool temperature and the lower bound of the pressure so that these two calculations have been disconnected. That was how I understood it.

MR. CROUCH: And that's correct with respect to how we make assumptions. I think what you're talking about, the differences there I would more character defining the event to start with like whether we get more water out or steam has to do with what our design basis break is, whether it would be a steam line break or a recirc line break.

Now we are choosing what we believe to be the bounding worse case event to start with, so we wouldn't, for instance, heat the pool up with a steam line break, but produce the containment pressure with a break in another location or something like that.

But as far as assumptions that you make that are plant-variable assumptions like what's the initial temperature, what's the initial pressure, those things are the ones that we manipulate to force the pressure down and the pool temperature up. But we don't change events.

DR. ABDEL-KHALIK: Let me just ask the question a little more directly. Are these results -- do these results come out of one calculation or two calculations? The temperature history and the pressure history.

MR. WOLCOTT: GE would have to answer the specifics of how they do that. They're asking how do you get the different assumptions to figure into the pool temperature.

MR. RAO: To maximize the pool temperature, what we've done, of course, is to use the initial conditions that are going to maximize the temperature. We start with the highest initial pool temperature and what we also have is a mixing model which artificially in a way assumes that the blowdown from the broken loop does not get held up in the dry well, at least most of it is directed to the suppression pool without mixing with the dry well atmosphere. What that does is it does tend to lower the dry well pressure and then by inference also the wet well pressure.

It also has the effect of directing the blow down into the suppression pool which tends to raise its temperature considerably higher. So to that extent we have been able to get some reduction in the dry well pressure and also simultaneously get the energy into the pool and raise its temperature.

MR. LOBEL: Let me try to ask the Committee's question in a different way and maybe this will help. Is the wet well pressure curve and the suppression pool temperature curve calculated with the same calculation at the same time?

MR. RAO: The wet well pressure and the suppression pool temperature, they are calculated from the same run, that's correct.

MR. LOBEL: Okay.

DR. KRESS: Sanjoy, I think what you would like to see, as well as us, we discussed this as part of the Vermont Yankee is the uncertainty analysis on both of these which gives you the two sigma, realistic two sigma on each of these functions. And we've never been able to see that.

DR. BANERJEE: Right, and that was --

DR. KRESS: You'd have to do a Monte Carlo or some other kind of nonparametric concerning the analysis.

MR. LOBEL: And the BWR owner's group are working on that.

DR. KRESS: Are working on that.

DR. BANERJEE: In the absence of that, I thought what was being presented here was two separate bounding calculations, one for the suppression pool temperature and one for the pressure.

DR. KRESS: I was under the same impression.

DR. BANERJEE: Up to now we've been living with that impression, so it's good that our impression has been corrected.

MR. LOBEL: I'm sorry, I didn't' realize there was the misunderstanding.

DR. BANERJEE: It's been going on since this morning.

MR. LOBEL: Okay. I think we -- I guess the only thing -- I think everything else has pretty much been covered, but I wanted to go through the cavitation part.

Next slide.

Okay, I think I already explained why it's important. You have two trains of RHR in the short term. One train is cavitating, the other train is injecting into the vessel. At the end of the short-term calculation, I do the long-term calculation and now I take a single measure of the train that was not cavitating. Now I'm depending on the pumps that were cavitating to cool the suppression pool.

That's why it's important. And why is it acceptable? As part of the review and when we got into talking about this, we asked the license to obtain the opinion of the pump vendor on the operation of the RHR pump and cavitation for the short-term LOCA and the pump vendor came back with these two statements that essentially say that there may be some damage, the damage won't be catastrophic. At the end of ten minutes, if the operational life graph is followed, which is that required NPSH curve that I was showing before. The pumps will continue to function.

MR. SIEBER: Are these vertical pumps or horizontal pumps?

MR. LOBEL: Vertical.

MR. SIEBER: So their cavitation performance, that differs significantly from horizontal shaft pumps. They have a tendency to surge more.

MR. LOBEL: Well, the pump vendor included surging in his analysis. Okay. So that was one basis for our acceptance. The other basis was cavitation tests that the TVA performed in 1976 on a Unit 3 RHR pump in situ in the plant. The purpose of the test was essentially the same scenario that we're discussing now. The test was run by taking suction from the Unit 3 suppression pool, and returning the water to the suppression pool.

The suction conditions were controlled by adjusting a valve upstream of a pump. The licensee operated the pump at several levels of cavitation. The pump motor vibration was measured during these tests, and the degree of cavitation was judged qualitatively by the suction pressure, the level of vibration, and by sound or the noise the pump was making.

The test report for these tests stated that in all cases, the pump motor vibration, displacements, and accelerations did not exceed the GE recommended criteria for pump motor vibration acceleration. This vibration was within the criteria for the pump. The pump was operated at several levels of cavitation, for a total of ten minutes, which is longer than what is being requested now for these RHR pumps. The margin between the three percent head drop value of required NPSH, the typical value and the lowest value of cavitation in these tests was nine feet.

We independently assessed the TVA test reports and found that they were acceptable based on the fact that the test appeared to be carefully run, data was recorded, the results of the tests appear reasonable and consistent with other information on these types of pumps and cavitation.

In addition to the pump testing, in addition to the vender's opinion, the pump testing that was done, there was a third aspect. We also asked TVA to address whether the 3A pump, the tested pump, had experienced any abnormal operation since the testing. The TVA went back and looked at the records and found no anomalies in surveillance testing or maintenance for the two years following the test of the pump.

In addition, in 1994, the 3A RHR pump

impeller was replaced to address a wearing, cracking concern that was a general concern, wasn't specific to Browns Ferry, and the documentation that was reviewed didn't show any indication of abnormal impeller wear.

So based on those three things, we found it acceptable -- oh, and one more thing. I'm sorry. The other thing is the licensee did a calculation, not a licensing basis calculation, but they did a sensitivity calculation where two of the conservative assumptions were relaxed. The relative humidity assumption was relaxed, and the pump flow was relaxed. The licensee assumed 11,500 GPM for the NPSH analyses, and system analyses showed that the pump flow would be 11,000. So with the relaxation of those two things, cavitation wasn't predicted. They still needed containment accident pressure.

CHAIR BONACA: Not cavitation, but you would still need it.

MR. LOBEL: The containment pressure was sufficient with the required NPSH curves. I won't say anything about special effects or the long term. I think they were covered pretty well unless you have any questions on those. They were all done with single analyses also. Like J.D. was saying, these special events calculations were done with realistic holistic assumptions, but a lot of the conservatism was in the initial assumptions. Station blackout for four hours when we have eight diesel generators. It's possible, but more unlikely than a plant with two diesel generators.

The more realistic calculation for ATWS showed that containment accident pressure wouldn't be necessary. The Appendix R assumption has a lot of conservatism built into the scenario.

Containment integrity. We talked about before. There's Appendix J for the leak testing, 10 CFR 50.55a for visual examinations. The nitrogen monitoring to make sure that as an indication that there's no leak, there's oxygen detectors in containment as another indication of no leakage. There's the difference in level between -- there's the different in pressure between the dry well and the wet well which determines the level of water in the downcomers which is a tech spec requirement that's monitored.

There's detailed procedures for ensuring that the containment isolation valves are in their proper position. All those things go into an assurance of integrity.

Operator actions, we already talked about the operator has curves in the emergency operating procedures that he can use to tell whether he has adequate NPSH. The curves are parametric and so they weren't changed for the power uprate. Those part of the procedures weren't changed.

In the analysis of the LOCA and other events, other special events where the sprays would be actuated, spray operation is assumed for the length of the accident, so the concern that the operator would turn off the sprays is covered by the fact that the sprays are assumed to operate for the whole accident time.

That's all I have.

CHAIR BONACA: Now this is need for 120 percent power. Now for 105 you wouldn't need as much.

MR. LOBEL: Right. And there are analyses that were done for -- well, I was going to say analyses were done for the power uprate at 105, but they weren't really. The licensee changed some assumptions so that the suppression pool temperature would be the same as before the five percent power uprate. So I don't have numbers offhand that I can give you for five percent. But it is true that 120 percent would be bounded. You'd be adding much more energy at 120 percent to the suppression pool than you would at 105.

CHAIR BONACA: Assume now we use the analysis, assume we say yes, it's acceptable and then they stay at 105 percent and never go to 120, so now we're giving them more than they needed. I mean one principle has always been that consideration for a relaxation of the requirements would be based on absolute need.

MR. LOBEL: Well, they're not getting more than the five percent because I probably should be addressing this because of the license is going to limit them to the five percent power uprate. There's no way they can go to 120 percent until the staff is ready to give them that. So even though they've done the analyses at a higher power level, they'll be limited by their license to the lower power and that's not that unusual a condition for the NRC to do that kind of thing. There are systems in plants that are designed using the higher power level, but the power of the power plant is limited by the license.

CHAIR BONACA: One question we have not asked is you know there is credit being asked of scenarios and did TVA look at the possibility of improving the RHR pumps or whatever so that the need for NPSH will not be there, or not as much? Did they look at that?

MS. BROWN: Bill? J.D.?

MR. WOLCOTT: J.D. Wolcott, TVA. Yes, we did. The only two ways, the only two options that we would have to eliminate the need for container overpressure would either be to create some more elevation head, which is fixed by the basic geometry of the plant, or to, for the long-term events, to increase our cooling capacity in some way by more RHR heat exchangers or more fundamental redundancy in the plant, both of which would have been expensive and fundamental changes to make. We didn't feel like there was a magic pump that could do, that could pump water at some of the temperatures we're talking about here without some assistance from elevation head.

MR. LOBEL: Let me make one more comment in general. This doesn't help Browns Ferry, but I think you have to realize where this stands in relation to all power plants. Most PWRs don't take credit for containment accident pressure. The BWRs that we've allowed credit for accident pressure are all the older Mark 1 designs. Even some of the newer Mark 1s don't need credit for containment accident pressure. Hope Creek is in for a power uprate now and they don't, they haven't requested credit for containment accident pressure.

The way the Reg. Guide 1.82 is written now, new plants would have to be designed so that they wouldn't have to depend on containment accident pressure.

So, we're really talking about early designs. People have since then paid more attention to this issue. Maybe, I'm not sure how to characterize it and so the newer plants don't have this problem.

CHAIR BONACA: Yes. Well, I'm not critiquing the existing plants. I'm critiquing the 20-percent power upgrade --

MR. LOBEL: Well, I understand --

CHAIR BONACA: -- it's a willful decision is being made --

MR. LOBEL: -- but we've had these generic discussions too and I just wanted to put it in a little perspective.

CHAIR BONACA: I'm just thinking about, you know, every single review that we have we present new specs. And here, there are more scenarios that we've had to give credit for and there is the issue of the short-term lack of sufficient NPSH and cavitation even if you take credit for back pressure. So, you know, this opens the question every time about what is appropriate. And, I don't think the conservatism discussion that you've made would seem to be as strong as the one I've seen before for the Vermont Yankee.

MR. LOBEL: No, it's not.

DR. BANERJEE: Do you have capability in-house to do some confirmatory analysis and maybe sensitivity analysis of some of these things?

MR. LOBEL: We, we, for Vermont Yankee, the reason we didn't do any for Browns Ferry was for Vermont Yankee, we did both the mass and energy release calculation and a containment calculation. The mass and energy release calculation was done with RELAP and the, and the containment calculation was done with CONTAIN2 the NRC code. And we got pretty good agreement in both, for both analyses, the mass and energy and the, and the containment analysis.

The mass and energy was actually the more independent analysis because the containment analysis, you know, you pretty much depend on the licensee's geometric description of the plant and the flows and that kind of thing. So there's a lot more input that comes from the licensee for the containment calculation than for the mass and energy calculation. But the mass and energy calculation, I believe, we showed that GE was conservative to RELAP.

DR. BANERJEE: The concern as you can see is that if you put more of the energy into the water, it heats it up more.

MR. LOBEL: Right.

DR. BANERJEE: And conversely, because more of the energy goes into the water the containment pressure goes further down. It doesn't go up as much. So, just by changing that partitioning, which was what I was saying, you can change the amount the water heats up and the amount containment pressurizes, now within a certain reasonable extent, of course. Within the --

MR. LOBEL: Yes.

DR. BANERJEE: -- uncertainties.

MR. LOBEL: GE, GE has done sensitivity calculations in the past for these types of calculations, where they, they looked at the NPSH for, in the same calculation they would look at the case where the suppression pool temperature was the highest and the case where the pressure was the lowest. And, and the conclusion was that the suppression pool, the case, the situation where the suppression pool temperature was higher was more limiting. So they have done a sensitivity calculation. I'm sure it wasn't done specifically for Browns Ferry. I'm thinking back to past things I've read. But that kind of sensitivity has been done.

DR. BANERJEE: Yes, it's a question of what is reasonable in doing this partitioning.

MR. LOBEL: And, and --

DR. BANERJEE: You know, it's not that easy to do without a confirmatory analysis.

MR. LOBEL: And this is an, well, like I say, we tried to do one for Vermont Yankee and, and this is a case where until power uprates, the old way of doing business, where you made everything conservative, was good enough. And what we found out, especially with Vermont Yankee and now with Browns Ferry is that making everything very conservative gets you into difficulties that you may not be in with a more realistic analysis. And that's why we think it's a good idea also to do this study of best estimate plus uncertainty.

DR. BANERJEE: Well, that's not going to help us with this.

MR. LOBEL: No.

DR. CORRADINI: May I ask a question? I was absent so you probably answered this and then I'll defer to a private thing.

Why did you stop at 600 seconds?

MR. LOBEL: By definition, that's the length of time for the short-term analysis. And that's based on the operator --

DR. CORRADINI: No operator action?

MR. LOBEL: -- operator action after ten minutes.

DR. CORRADINI: And then after that, all bets are off. What, that something then else can happen to --

MR. LOBEL: After that, you assume a single failure and you do a different analysis.

MR. LOBEL: The limiting situation for the short term is really the RHR pumps, the RHR flow rate out the broken loop. You're, you're close to run-out. You would be at run-out at Browns Ferry if they didn't have orifice plates to limit the flow. So, so in the short term, it's the flow rate that gives you the problem. In the long term, it's the suppression pool temperature. High suppression pool temperature.

DR. ABDEL-KHALIK: Can I ask a question about the calculations, which you present the results on, slide number nine? Who did these calculations?

MR. LOBEL: TVA did.

DR. ABDEL-KHALIK: So the NRC did not do any independent calculations in this regard?

MR. LOBEL: We didn't do any for -- we didn't do any for Browns Ferry. Like I said in the previous power uprate review, Vermont Yankee, mass and energy calculation and a containment calculation. Those results are in the Vermont Yankee SER. There are curves in the Vermont Yankee SER comparing the staff and the licensee's calculations.

DR. ABDEL-KHALIK: Thanks.

MS. BROWN: Okay, we are going to transition into Marty Stutzke's discussion on the risk considerations for containment accident pressure.

(Pause.)

MR. STUTZKE: All right, here I am. For my second presentation of the day, we will focus strictly on the risk evaluation containment accident pressure credit. Mr. Laur (5:18:01) is in the audience now, so hopefully he provide to me a little defense-in-depth.

(Laughter.)

Slide 2.

Just a quick recap for Units 2 and 3, there already is a pressure credit on a design basis LOCA, station blackout, ATWS and Appendix R as you know. I'll point out these are deterministic types of events. These are not the way that they would normally be modeled in a PRA.

DR. WALLIS: Marty, I wasn't here, as you know, but how much CAP credit is being asked for for the Appendix R scenario?

MR. STUTZKE: Bounce that to TVA.

DR. WALLIS: It's 9 psi for quite along time.

MR. STUTZKE: Up to 9, 68 hours.

DR. WALLIS: Isn't that unusual?

MR. STUTZKE: I believe it's the largest one we've seen.

So as part of the 120 percent EPU amendment they requested the credit for Unit 1 and an increase in the existing credits for 2 and 3.

TVA requested the credit for the 105 interim power uprate.

Switching to slide 3, the high level approach from making the risk evaluations based on this concept under certain configurations, plant conditions, loss of integrity of the containment implies if you lose the overpressure, the low head pumps go into cavitation and you lose their function. This is a little different than we did at Vermont Yankee. At Vermont Yankee we made the bounding assumption that whenever you lost the containment integrity, the pumps were in trouble. Here, we're restricting -- we tried to identify combinations, equipments and certain plant conditions.

I will give you on the next slide exactly what we mean by that. But basically, it's trying to look at the uncertainty and some of the input parameters such as the river water temperature and things like this, explicitly inside the risk assessment rather that bounded.

As far as failure modes of the containment, two are considered, the pre-existing leaks, the probability depends on the interval between integrated leak break test. As you know, Browns Ferry containment is inerted if a leak were to be develop, it could be detected by the nitrogen makeup of the containment. There's no credit for that in the estimate of the probability of pre-existing leaks.

The other way that's considered is the failure to achieve containment isolation. We had discussed a little bit earlier. We don't consider loss of integrity after the isolation has been achieved. So it's not time sensitive in the risk calculation. For example, we don't model spurious opening of motor-operated valves.

I did a little back-of-the-envelope

calculation over there. A typical failure rate for something like that is on the order of 10^{-7} per hour so times 24 hours gives you 2E-6. These two failure modes up here right now have a combined probability on the order of 10^{-3}.

Dr. Powers had asked questions about seal failures, what I'll call induced failures due to thermal transients or radiation. Those are not included in here. Probably another way to lose containment isolation would be some sort of human error. This would be, could be treated as an error of commission. As you know, and you've heard from the Office of Research, you would have to use their high-powered human reliability technique called ATHENA, just not officially out.

DR. POWERS: What if you used their low powered THERP methodology?

MR. STUTZKE: You can't treat the commission error. You don't know the estimate of the probability that the operator just decides to open the containment up.

DR. POWERS: I understand.

MR. STUTZKE: The problem with ATHENA is that it requires an expert panel and I think there's only three experts in the world.

(Laughter.)

The point I'm trying to make is bear in mind that the total loss of containment integrity that's used in the study is on the order of 10^{-3} and ask yourself could we be really off from that number and does it matter?

Slide 4. Unlike the design basis, deterministic calculations that Mr. Lobel was talking about, we tend to use or try to use realistic thermal-hydraulic calculations. To be honest, realistic is in the eye of the beholder. To me, it means we don't deliberately introduce conservatisms, so we're not using two sigma on the decay heat curve. It's unwieldy.

DR. KRESS: You also don't do a Monte Carlo and look for the uncertainties.

MR. STUTZKE: That's true. So we end up with this set of success criteria, but let explain this a little bit so you're clear. What it says is for the large LOCA, if you're running three or four pumps in suppression pool cooling, you don't meet containment integrity. There's no -- the pumps won't cavitage, even if you open the door to the containment.

If you're down to two pumps in suppression pool cooling, you may have a problem under certain plant conditions.

DR. WALLIS: I'm sorry, Marty, this is simply using an analysis with no consideration of uncertainties?

MR. STUTZKE: It depends on what you mean by uncertainties. The uncertainty that the licensee treated was in the second bullet here, with two pumps under certain conditions, so they're trying to treat the --

DR. WALLIS: Your first conclusion is based on what you call a realistic analysis?

MR. STUTZKE: Right.

DR. WALLIS: So it's sort of a mean of all possible analyses or something like that?

MR. STUTZKE: Not a formal mean, but the intent --

DR. WALLIS: It's somewhere in the middle of all possible analyses with all sorts of uncertainties, so it could well be that let's say a 20 percent chance that this won't work.

MR. STUTZKE: It's possible

DR. WALLIS: It's not unreasonable, right?

MR. STUTZKE: For the probability of having unfavorable plant conditions for the second case is on the order of 10^{-2}. So what that's saying is -- the idea is you have a large LOCA when it's hot in Alabama and you may be in trouble. That's the gist of what this --

DR. WALLIS: Same thing when it's hot in Vermont.

MR. STUTZKE: So they've made an effort to treat some of the uncertainties this way, the aleatory part, certainly not the epistemic part like this and it's treated very simplistically in the PRA. They define plant operating states or conditions that would be unfavorable to this. It's not a full-blown Monte Carlo treatment like that.

Then down at the bottom for --

DR. WALLIS: Excuse me, you put in the statistics for the river water temperature?

MR. STUTZKE: Yes, they do.

DR. WALLIS: They do, okay.

MR. STUTZKE: All these parameters.

DR. WALLIS: Okay.

MR. STUTZKE: Slide 5, the other initiators. This is perhaps more interesting. First of all, the presumption is containment integrity is always needed for the station blackout, ATWS and Appendix R scenarios. What's important to realize is that Appendix R scenario was generalized to look at a broader set of PRA sequences as this Committee had suggested a number of years ago like that.

And the reason is this, is when I started to look at the definition of the Appendix R scenario, they're talking about a loss of power conversion system and a failure of all the high head injection sources, so HPSI is gone, RKSI is gone, depressurization by opening multiple safety relief valves and then starting either for spray or LPSI pumps, RHR pumps operating in the LPSI mode like this.

And that created a demand for containment over pressure. Now in the deterministic world, people like to say this is an unlikely scenario. In the PRA world, this is always modeled in PRAs, this depressurization and getting on to the low head pumps. So Mr. Laur and I saw this and we set to work to try to estimate it.

So we considered all sorts of PRA initiating events where there's lots of maintenance or heat sink, less than two RHR trains, suppression pool cooling, that's a judgment call. It seemed reasonable. And either we had to ask for depressurization after a loss of all the other high pressure sources or we considered some stuck open multiple relief valves like this.

The licensee made calculations. We did confirmatory calculations using the SPAR models, the standardized plant analysis of risk models maintained by the Office of Research and the results are shown on Slide 6. These are the breakdowns.

DR. WALLIS: This is a change in CDF, yes.

MR. STUTZKE: You can interpret -- these are the change compared to as if no overpressure credit was required. Okay, so it's the true change in CDF for Unit 1. For Units 2 and 3 they already have an overpressure credit. So it's not really the change.

The way to look at this, this is roughly, the total is roughly 10 percent of the total core damage frequency of the units. About 10 percent.

And I'll call your attention, if you look at the contributors to large LOCAs, ATWS, aren't contributing very much, station blackout is a little bit higher, it was the other transients, the expansion of the Appendix R scenario that was driving this answer like this.

The only other thing I'll have to offer is the credit for containment accident pressure is not the largest risk contributor of the extended power uprate nor is the human reliability.

DR. CORRADINI: Are we allowed to ask what is?

MR. STUTZKE: I thought I would leave you in suspense until I come back tomorrow afternoon.

(Laughter.)

DR. WALLIS: We can guess tonight and see if we're right.

(Laughter.)

MR. STUTZKE: I can see Jack getting nervous.

(Laughter.)

MR. STUTZKE: I'll give you a hint, they changed the success criteria as a result of the power uprate.

DR. WALLIS: Was your conclusion that this sort of unusual containment pressure allowance should be granted?

MR. STUTZKE: The conclusion is we haven't identified special circumstances that would say put on the brakes and stop it within the limits of this type of calculation. For example, that 10^{-7} total, if it is interpreted as a delta and I plot it against the baseline risk of 10^{-6}, it's not even on the graph for Reg. Guide 1.74, it's such a small risk contribution.

You're either tired or I've answered your questions.

(Laughter.)

DR. CORRADINI: You can ignore her. She's just tired. So the other transients are all Appendix R related? That's what I thought you said.

MR. STUTZKE: It is a development or generalization of the Appendix R to all of the other internal events PRA initiators. Loss of offsite powers that don't go to station blackout, loss of feed water, loss of condenser heat sink, loss of service water. All of them are there.

DR. CORRADINI: So it is a judgment on how this sort of effect would affect everything else?

MR. STUTZKE: The problem, what I was trying to convey before was the description of the Appendix R scenario looks like sequences in the SPAR model. For all the initiating events. They're classic BWR risk sequences. So we modeled them.

DR. KRESS: That was good. In the PRA, how did you treat the pump cavitation. I mean, you can assume --

MR. STUTZKE: I mentioned that maybe too briefly before. The assumption is once containment integrity is lost, the pump is totally failed. We don't consider degraded flow out of the pump.

CHAIR BONACA: So you had scenarios where the pump is lost?

MR. STUTZKE: Totally lost. Not to come back.

CHAIR BONACA: Not just one pump?

MR. STUTZKE: Multiple pumps.

MS. BROWN: Thanks, Marty.

(Laughter.)

MS. BROWN: I think next we're going to have TVA to come up and discuss fuel methodology and fuels issues. I guess my only question is this portion of the meeting needing to be closed? You told us that there was no --

MR. CROUCH: We intend to keep this in open realm. If we start getting questions such that we have to delve off into proprietary information, at that time we will identify it.

MS. BROWN: Thank you.

DR. WALLIS: Since I have no idea what happened today, I'm now in charge. Go ahead. Enlighten me.

MR. CROUCH: We have with us here Greg Storey who is our BWR Fuels Manager with TVA. He is going to make the basic presentation. We also have with us with the GE Fuels people here. I'm going to turn it over to Greg. If we start getting into certain aspects of the fuels analysis, we may have to declare it to be proprietary information, and we have some other people here that we would like to step out of the room if that occurs. We'll let you know if it comes to that situation.

So Greg?

MR. STOREY: Okay. I'd like to start off just with an overview of the Unit 1 core design for the restart core. It is primarily fresh fuel in the core. It is composed of a mixture of GE13 and GE14 bundle designs. GE13 bundle design is a 9x9 matrix fuel design, whereas the GE14 is a 10x10 fuel design. There are 564 GE14 bundles in the interior of the core, and those are in our high power interior locations.

In addition, there are 108 GE13 bundles and these are in near edge low power locations. Thy are one row in off of the periphery of the core. The core periphery itself is not fresh fuel. It is made up of exposed reinsert fuel. These 92 bundles are also a mixture of GE13 and GE14 fuel, and this fuel comes from Unit 2 fuel that was discharged at the end of the prior cycle, which would have been the spring of 2005.

The GE13, GE14 designs, those are industry proven designs. They have been used extensively throughout the industry. They have also been used at both of the sister units at Browns Ferry. The core design was done with NRC-approved methods. TG006 Code, which is the lattice Physics Code, and the Panic 11 code is the 3D simulator code.

Next slide.

One of the design considerations was the cold shutdown margin design goal that we used on this core. The Browns Ferry 1 Restart Core is somewhat unique in the fact that it's the first core that contains all fresh 10x10 in the interior positions. So there is very limited information on which to pick the reactivity basis of this core. So rather than use the standard one percent design margin, we've decided to increase this to 1.5 percent. This is roughly a two sigma increase on the cold Eigen uncertainty. Just to point out the tech spec that we have to meet is .38 percent, so we have a substantial margin when we use 1.5 percent.

Contingency studies. What we're doing here is looking at what is a similar effect on the hot reactivity. What if our hot reactivity basis that we're developing the design with should be off by a half percent in both directions, both more reactive and less reactive. GNF was able to develop control rod patterns on those altered bases that achieved acceptable thermal limits and power shapes.

So our conclusion is that the core design is very robust and it is very tolerant to the effect of these design uncertainties on reactivity.

Next slide.

Moving into the reload analysis for the 105 percent power, of course we did an analysis last year to support the 120 percent power and that was submitted in mid-2006. For the 105 percent transient analysis, there is almost a complete redo of what we did for the 120 percent. We did consider the use of the maximum extended load line limit domain which is consistent with the Unit 2 and 3 licensing basis.

Also, all of the rated power transient analyses were rerun at 105 percent power and that is consistent with the GESTAR-II requirement that all rated power transients be done at the licensed power level.

In addition, we have off-rated thermal limits. These are power-dependent limits. They are primarily a multiplier on the rated thermal limit.

There are a few at very low power that are not a multiplier and I'll talk about that in a second.

These are cycle independent and they're not intended to be done each cycle. The approach we used here had the limits derived originally for 120 percent power. These have been scaled down, based on 105 percent power operation for those that are multipliers and there have been validation cases run to show that that scaling approach is reasonable for those intermediate powers.

At very low power, there is no multiplier in the limits. They are actually absolute limits and those were specifically reanalyzed based on the 105 percent being the license thermal power.

Next slide, please.

The next area we looked at on 105 percent power is the safety limit MCPR. Here, a complete reanalysis of the safety limit MCPR was performed based on 105 percent power operation. Operating at 105 percent power you're going to have different control rod patterns, and different power history that you build into it. So this was complete reanalysis at 105 percent and it considered both the low core flow of MELLA and the rated core flow. It has been shown that the low flow point can be the limiting point and indeed in this case that is what happens with Unit 1 restart core.

The conclusion of that analysis was that the safety limit calculated based on 105 percent is bounded by the 120 percent result that was submitted previously.

The area of stability analysis again, here's an area where operation at 105 percent power you're going to have a different power history, different control rod pattern that the analysis is starting from. Here we have another complete analysis being done to demonstrate that the stability set points that we're going to put in place will protect the MCPR safety limit.

DR. ABDEL-KHALIK: When will we see the details of these analyses?

MR. STOREY: These results will be in the supplemental reload licensing report for 105 percent. That's the document Bill alluded to earlier today that we owe at the end of January.

DR. ABDEL-KHALIK: So these analyses will be done at 105 percent power?

MR. STOREY: Right. There's stability analysis at 105.

DR. ABDEL-KHALIK: The plant uses Option

3?

MR. STOREY: Option 3.

DR. ABDEL-KHALIK: Right, now over the years, several Part 21s issued for Option 3 plants. Now while the plant was shut down, how did you handle all these Part 21s?

MR. STOREY: Well, the primary Part 21 was the DIVOM curve which relates to the delta C curve thermal limit to the oscillation magnitude and that has been incorporated through plant-specific DIVOM analysis for Units 2 and 3.

Similar thing was done for Unit 1 when the 120 percent licensing was done. There was a cycle-specific DIVON curve done.

DR. ABDEL-KHALIK: So you had a core design for the 120 percent power for which you generated this --

MR. STOREY: This DIVOM, yes.

DR. ABDEL-KHALIK: But now you're going to do this for 105?

MR. STOREY: For the 105 percent, there are validation cases that show that that DIVOM slope is applicable to the 105 percent condition. All other remainder of that 105 percent stability analysis is a standard stability analysis, using the normal GE process.

DR. ABDEL-KHALIK: Now there have been other Part 21s issued for stability analysis. Do they apply at all?

MR. STOREY: I'm going to look towards GE to field that question.

MR. BOLGER: This is Fran Bolger from GE. I'm not sure what other Part 21s you're referring to.

DR. ABDEL-KHALIK: I think there have been some issues related to Nine Mile Point.

MR. BOLGER: Yes, there has been. I believe -- I'm not an expert in this area, but the calculation of the OPRM was -- there was some revisions made to that process as a result of the Nine Mile Point Two and that been incorporated in this analysis.

MR. CROUCH: We'll check back with our staff and get back to you. We'll take that as an action and get back to you and let you know about the other Part 21s.

MR. STOREY: I'm ready to move on to the next slide.

On the LOCA analysis for 105 percent power, what we're using for Unit 1 is the current three unit analysis of record which addresses 105 percent power for both the GE 13 and GE 14 fuel types. So therefore no additional analysis was required at 105 percent. That analysis was done in 2005.

On shutdown margin, as I mentioned earlier, we did use the increased goal of 1.5 percent. We did show that the effect of the 105 percent power operation does not cause us to drop below that 1.5 percent value. We still maintain that margin.

Also, the standby liquid controls system shutdown margin was unaffected by the operation at 105 percent. This is because it occurs at beginning of cycle. So it would not be affected by the power history.

DR. BANERJEE: Which plants have the Areva fuel now?

MR. STOREY: Two and three.

Next slide, please.

And the conclusion slide here, we really feel that that the Unit 1 Cycle 7 core is a robust design. It uses industry-proven fuel types and we have, as I mentioned, incorporated additional reactivity margins to account for the unique nature of the all fresh 10 by 10 core.

Unit 1 licensing --

DR. WALLIS: The fuel that's in there now is capable of 120 percent.

MR. STOREY: Correct.

DR. WALLIS: That's what it's really designed for.

MR. STOREY: The core was based on an EPU operation, yes.

Unit 1 licensing analyses are finishing up for 105 percent power. As I mentioned, complete transient analysis at rated power is being done and significant work at operated conditions. Safety-limit value has been shown to be applicable at 105 percent power and the impact on stability analysis is being addressed through a specific stability analysis at 105.

We believe Unit 1 licensing for 105 percent is basically a typical GNF reload using NRC-approved methods with the exception of the additional shutdown margin that we designed into the core.

So that concludes my presentation, if there's any questions.

DR. BANERJEE: Has any LOCA analysis been submitted for the 120 percent?

MR. STOREY: That was in the task report and in the PUSAR report, contains LOCA results for 120 percent.

MR. CROUCH: The LOCA was reanalyzed 120 percent, yes, as part of our submittal to be made June of 2004.

DR. ABDEL-KHALIK: The core has 564 GE-14 bundles, fresh bundles and 108 GE-13 fresh bundles. Is there any reason why you decided to use a mixed core, rather than using all GE-14 for example?

MR. STOREY: Yes, it's -- without crossing into proprietary or commercial space, there's a financial advantage to doing that. That's -- without getting into proprietary session, that's really all I could say. It's economic reasons.

DR. ABDEL-KHALIK: And there are no sort of problems associated with using a mixed core that would override that economic advantage?

MR. STOREY: No, we don't believe so.

DR. CORRADINI: Are we allowed to -- we're not allowed to ask anything. Can you tell me the difference between a GE-13 -- I'm looking carefully, Said seems to know a lot more. What's the difference between the two bundles?

MR. STOREY: As I mentioned, the 13 is a 9 by 9 fuel design. The GE-14 is a 10 by 10. Primary reason we didn't locate the GE-13 in the interior of the core is the GE-14 has higher inherent thermal margin capability.

So having that --

DR. CORRADINI: And 13 is on the ring?

MR. STOREY: Right, that's why we have them in a low-duty area, so they're not limiting locations.

DR. WALLIS: Are these tailor-made fuels with sort of graded poisons and all that along the length?

MR. STOREY: It does have access in it and both fuel types have part-length rods.

MR. CROUCH: Anything else, Dr. Bonaca?

CHAIR BONACA: I don't think so. Any other questions on this?

MR. CROUCH: Okay.

(Pause.)

CHAIR BONACA: Let's proceed.

MS. BROWN: All right, for our last presentation of the day, staff is going to discuss fuel and reactor systems. I just wanted to open up and let them answer the question that we got this morning on the OPRM application of effects on the power uprate on the OPRM.

MR. THOMAS: My name is George Thomas. I'm from the Reactor Systems Branch. Regarding the

OPRM operation, there is no difference when you are operating at 105 or 100. It's all the same.

MS. BROWN: Was there a need to go into any more detail? Okay.

DR. BANERJEE: Said asked the question.

DR. CORRADINI: That was way too fast for me.

(Laughter.)

DR. ABDEL-KHALIK: If there is certainly going to be a large difference in the analysis as to whether you do the analysis at 100 percent power or 120 percent power, the stability analysis. The hardware may be the same, so I can -- I understand that. But I was much more concerned about doing the analysis at the higher power level. Has that analysis been done?

MS. BROWN: Let's focus to TVA as far as the analysis on the OPRM at 120 percent.

MR. STOREY: Like I said earlier, there's a complete analysis that was done for the 120 percent power. And keep in mind you are on the same rod line, regardless of whether it's 105 or 120. We're not raising the license rod line.

You have the two-pump trip. You're going to end up back at a natural circulation condition.

Starting rod pattern would be slightly different. That's really the only difference in the analyses.

DR. KRESS: My impression was that it made the stability, instability region a little bit larger, so you got into it a little bit sooner on the rod line.

Is that -- do I remember that correctly?

MR. BOLGER: This is Fran Bolger from GE. I wouldn't expect that the stability region to be much different. The core design is the same. You're looking at the conditions around the natural circulation condition, up the maximum rod line and also along the natural circulation line and in what the calculated K ratios are, if you were to calculate region boundaries should be very similar, independent of the two power level.

MR. MARCH-LEUBA: This is Joe March-Leuba from NRC staff. The problem is very complicated and I have to say often real life is like an onion, it has many layers, okay?

DR. CORRADINI: It makes you cry.

(Laughter.)

MR. MARCH-LEUBA: On first observation you can present it as a homogeneous sphere and on that first observation the statement is correct. Once --

stability is a problem when you trip the pumps. Once you trip the pumps, you don't care where you were to start with. So you end up exactly at the same location. So first of all observation, there is no effect. When you start peeling the layers, you find some differences and the differences are power distributions. You have to load different fuel. And I agree with you Dr. Kress that the region will be a little larger, but not significantly.

All three Browns Ferry plants use solution 3 which is a detect and suppress solution in which the --

DR. CORRADINI: Could you say that again?

MR. MARCH-LEUBA: All -- meaning that you allow the solutions to occur and then you scram if they happen. So the size of this crucial region which no other solution is important is not relevant in this case. You will have more events, more challenges to the protection system, but the protection system will still work the same.

So in that sense --

DR. KRESS: Thank you.

DR. WALLIS: We have to have faith that it will work. I guess we have faith that it will work.

CHAIR BONACA: Let's hear about the fuel

and reactor systems.

MS. BROWN: All right. The reactor systems review is contained in Section 2.8 of the safety evaluation.

For the reactor systems' review, the staff looked at the following areas: fuel system and nuclear design, thermal-hydraulic design, overpressure protections, standby liquid control, the transient analysis for LOCAs and anticipated transient without scram.

For this presentation, the results are applicable for all units up to 120 percent. Please note that the fuel system and nuclear design discussion today is applicable for Unit 1 only. So I mean let me just say that one more time. That the fuel system and nuclear design discussion today is applicable for Unit 1 only.

DR. BANERJEE: Those other analyses are not fuel sensitive?

MS. BROWN: No, sir. Our discussion today will only be limited to Unit 1 for those fuel things. Our intent is to come back to you in March to discuss any issues that are outside of Unit 1, 105, because in some cases the staff's review is not complete.

The staff's review was conducted using the generic guidelines and evaluations from the extended power uprate topical report. The staff found that with the exception of certain thermal limit concerns covered by TVA in the previous presentation, the Unit 1 fuel and nuclear design review performed at 120 percent that bounds the 105 submittal.

TVA has indicated that although Units 2 and 3 are currently operated with mixed cores of Framatone and GE fuel, Unit 1 will restart cycle 7 with only GE fuel. The core contains 564 fresh GE-14 and 108 fresh GE --

DR. WALLIS: I'm sorry, I wasn't here earlier, but you said there was this increase of 165 megawatts, but in fact, when I was reading the SER, I keep seeing this figure of 3954 or 52 or something. SER is full of stuff which is 120 percent.

MS. BROWN: In some cases, well, in a lot of cases, the analyses were performed conservatively --

DR. WALLIS: This seems to be inconsistent. Sometimes you talk about 105 percent and yet the megawatts, it's as if the editing wasn't done properly or something.

MS. BROWN: I think --

DR. WALLIS: Inconsistent.

MS. BROWN: Yes, sir. We'll go back and take a look at that. In some cases, I think we are addressing the analysis which sometimes --

DR. WALLIS: It appears as if you're talking about 120.

MS. BROWN: Yes, sir. In some cases that's the case.

DR. WALLIS: It's very difficult for the reader to figure it out.

CHAIR BONACA: Clarification. I asked for clarification when we started the meeting.

MS. BROWN: Yes, sir.

CHAIR BONACA: My understanding is that the rating was done at 120.

MS. BROWN: Yes, sir.

CHAIR BONACA: And the only exception is the fuel.

MS. BROWN: That's correct.

CHAIR BONACA: I agree with the comments of Dr. Wallis here. When you go through the SER, it refers to 105 or 120 or EPU, whatever. It's good for everything, but I mean at least we got the clarification.

MS. BROWN: Thank you.

DR. WALLIS: So we therefore are reviewing the EPU today?

MS. BROWN: Selected items that where the analyses for new methodology was the same regardless of the power level and for a good deal of the power uprate that is true.

CHAIR BONACA: I would say for the NPSH discussion to be identical for 120 because it's all based on 120 percent power.

MS. BROWN: There are some areas that we're aware of that are --

DR. WALLIS: When you talk about MAPLHGR you're talking about 120 percent?

MS. BROWN: I'm sorry.

DR. WALLIS: When you talk about MAPLHGR, you're talking about 120 percent?

All these refer to 120 percent then?

MS. BROWN: Yes.

DR. WALLIS: Okay.

MS. BROWN: In this discussion, we're talking about Unit 1 only. Any time we have GE on a slide, we're only talking about Unit 1.

DR. WALLIS: I understand that.

MS. BROWN: Okay.

DR. CORRADINI: And I think he was asking about the power level.

DR. WALLIS: Yes.

DR. CORRADINI: Relative to this.

DR. WALLIS: Yes, because it wasn't clear to me.

MS. BROWN: Well, there's the possibility that TVA will be going to 120 percent this cycle. As far as we talk about the amount of fuel and the way it's aligned in the core, it should be consistent, unless they do something strange.

CHAIR BONACA: But the cycle of 7 thermal limits evaluated, those are at 105 percent power?

MR. THOMAS: No, the Cycle 7 Supplemental Report was all based on 120 and at the end of this month, we are going to get the 105 Supplemental Report. That will be a confirmatory review.

DR. ABDEL-KHALIK: I'm sorry, the analyses you said you did before at 120 percent power used exactly the same core design.

DR. WALLIS: You need to talk into the microphone, Said.

DR. ABDEL-KHALIK: I was just asking if the analysis that he referred to as being done at 120 percent power was done for exactly the same core design described to us for which the calculations are currently being done at 105 percent.

MR. STOREY: Greg Storey, yes, that is correct. It's the identical core design in both cases.

DR. ABDEL-KHALIK: Okay, thank you.

MS. BROWN: All right, I think TVA had already gone through the numbers of the GE-14 and the GE-13 fuel. And we just discussed the fact that the thermal limits that were provided in Cycle 7 SRLR for at 120 percent back in May.

The requirements contained in the tech specs and the approved methodology contained GESTAR II requires a cycle and core specific reload analysis to be performed. It should be noted that although these documents require the performance of these analyses, they are not required to be submitted to the staff for review and approval, although the COLR is routinely provided to us at a frequency that's outlined in the code.

However, for the EPU and the 105, the staff requested submission for review of the Unit 1 analysis. The staff's review concluded that the staff's fuel design and operation review conducted at 120 percent should conservatively bound the 105 percent --

DR. WALLIS: Are you going to give us any numbers on this? I read the SER and it seems to be very devoid of anything quantitative?

MS. BROWN: Yes, sir.

DR. WALLIS: Why don't you actually put numbers on? If there's been a change in these fuel limits or something, why can't we see some numbers to know what's changed, rather than just know that the staff is happy?

MR. THOMAS: In the PUSAR, if you want to go into the numbers --

DR. WALLIS: I have to go back to something else to find it. Okay.

MR. THOMAS: I have numbers also in the slide and LOCA results are given. LOCA is there.

DR. WALLIS: LOCA is very sparse too. We're going to get to that as well, are we?

MS. BROWN: We're going to touch on it briefly.

DR. WALLIS: But you don't requote the numbers in the SER. You just say you're happy. What I tend to look at is the SER, rather than having to dig into the other stuff which is sometimes difficult to find.

It's very difficult for me, especially when a lot of extra RAIs and things to find out where the evidence is.

MR. THOMAS: In the SER we tried to put down important results, not everything --

DR. WALLIS: But not much in this SER. It's very short on numbers, this particular SER.

MS. BROWN: Yes, sir.

DR. WALLIS: And I don't know why that should be because we've tried to make you in the past tell us more about why you reached the conclusions you reached. I thought you've been doing a very good job until we get to this one which seems to slide back.

MS. BROWN: Yes, sir. Well, I think we felt that for the 105 that that increase was not as big as what we would expect for the 120 percent, so the level of detail may not have been --

DR. WALLIS: When we get to 120 percent, we're going to see the detail?

MS. BROWN: It's going to be huge.

(Laughter.)

MR. THOMAS: More detail, yes.

DR. CORRADINI: She assured us of that multiple times this morning.

MS. BROWN: The LOCA detail that's in the 105 --

DR. WALLIS: That's rather strange,

because I thought this whole idea of 105 was somehow to avoid having to go over it again when you got to 120 and that's not the case.

MS. BROWN: For the safety evaluation, that's just for presentation.

However, for the EPU in the 105, the staff requests that submission for review of the Unit 1 analysis. The staff's review concluded that the fuel design and operation review conducted at 120 percent should conservatively bound 105 percent operation.

However, the staff was concerned that the prolonged changes in operation could affect core power distribution which can affect the required increases in SLMCPR.

As previously discussed by TVA, they had GE reperform the submit recalculation using a limiting control rod pattern at a limiting stake point. The results indicated that the SLMCPR thermal limit calculation appears to remain acceptable.

As Jose indicated, Browns Ferry is implementing the Option 3 long-term stability solution. TVA used staff-approved methods and hence they were found acceptable.

Up here we also discuss that they are implementing the detect and suppress; that they're using the hardware with the CD Scram disabled. So what you end up with is effectively Option 3 which is upgradable at a later time for the DSS/CD --

DR. WALLIS: When I looked at this, it seemed to me that you were saying they were using GE methods, therefore, everything was going to be all right. But I didn't see sort of a bottom line which said it met some criterion. Does no criterion apply to this sort of thing or is it just if they use the GE methods everything is going to be all right?

MR. MARCH-LEUBA: This is Jose March-Leuba. There are approved methods to be used for long-term solutions and what we say in the SER is that they follow those approved methods that were approved --

DR. WALLIS: How do you know that the answer is okay?

MR. MARCH-LEUBA: Because those methods were approved.

DR. WALLIS: And always work? They always work for any power level?

MR. MARCH-LEUBA: Yes.

DR. KRESS: Actually, we approved, we heard discussions on these and we agreed --

DR. WALLIS: All right, so it's all right to say they used the right methods and everything is all right?

MR. MARCH-LEUBA: It's not the methods. It's the methodology, the hardware and the way they have suppressed the solutions. Solution 3 has been installed in power plants for now, since the early 1990s.

DR. WALLIS: But there must be some power level where you begin to get into trouble when you use it?

MR. MARCH-LEUBA: No.

DR. WALLIS: Never? There's no way you can increase the power so much that you make the thing unstable, no matter what you do?

MR. MARCH-LEUBA: Then you scram, no matter what you do.

DR. WALLIS: Oh, so just suppressing is okay. If you wait until there's a disaster, then you prevent it.

MR. MARCH-LEUBA: Correct.

DR. WALLIS: Potential disaster.

MR. MARCH-LEUBA: There are two general design criterias. They are 10 and 12 and you are allowed to detect and suppress the solutions. That's why it's called detect and suppress. If they keep on scramming every other week, that's their problem.

(Laughter.)

DR. WALLIS: That's an interesting solution.

MR. MARCH-LEUBA: Yes, but it allows them a lot of flexibility. There are other solutions like Solution 1A which is preventive. It's a better solution, but it does not have the operating flexibility.

DR. ABDEL-KHALIK: But disabling the confirmation count, is that done in response to some recent Part 21?

MR. MARCH-LEUBA: No, the confirmation density is a brand new long-term solution which is designed specifically for MELLA plus and it's called DSS/CD. And this plant and its operator, General Electric methodology. Option 3 -- Browns Ferry 3 had to purchase the hardware from General Electric to implement Solution 3. So they went ahead and purchased the newest hardware which is the CD hardware and disabled the CD algorithm then it reversed to be an Option 3 algorithm.

So basically, they are ready to go to the DSS/CD and if and when they were able to MELLA plus. They already have the hardware, but it's not armed.

As far as we're concerned, it's an Option 3 hardware, everything reversed.

The set points, there are some set points that are associated with Solution 3 which are the scram set points and those are calculated on a cycle specific basis and the only realm of parameter really is the power distribution. The radial and axil peaking factors.

MR. HUANG: This is Tai Huang. Just to supplement the question you had, Part 21 issue. This set point is a cycle specific set point, so every cycle the power change and core design change, they have to input that to come out with a slope to fit into their point specific design. So from there the methodology or Option 3 that come out at trip set point calculation.

MR. MARCH-LEUBA: Okay, since I have the microphone, Said, you were asking about the normal point events. With that resulting recommendation for the newest owner's group and the owners' group to tighten some of the parameters of Option 3, they have written to be very non-sensitive. Most plants, because of the noise issue have been relaxing the sensitivity of Option 3. After Nine Mile Point where it tripped like 20 seconds after everybody -- it was supposed to, the recommendation was to tighten those parameters and make them more sensitive.

Dr. Huang and myself went to Browns Ferry to audit all those implementations in preparation for this meeting and we checked that they indeed are following the owner's group, the newest owner's group recommendation and have all the parameter settings following the lessons learned from Nine Mile Point.

So those parameters are the corner frequency and the EPU tolerance.

So we confirmed that they have followed those to our knowledge.

MS. BROWN: All right, overpressure protection. For the Browns Ferry units, each unit is 13 SRVs which are used to provide overpressure relief. As the reactor steam dome pressure is being increased, the opening pressure set points were raised.

The overpressure transient was performed using a staff-approved methodology assuming 120 percent conditions. As a peak pressure calculator, it made above the ASME limits, the staff found this analysis acceptable for operation of Unit 1 at 120 percent which remains bounding for operation at 105 percent.

For SLC, the main effect is the need for the increased boron concentration and a change to the system relief valve setpoint. The staff reviewed the need and the amount of the boron concentration as part of the alternate source term review which was completed outside this application.

DR. WALLIS: This is used in -- are we going to talk about ATWS?

MS. BROWN: Yes, sir. We're going to get to ATWS a little later.

Transient Analysis. Most of the limiting transients specified in the extended power uprate licensing top core were analyzed in a Cycle-7 SRLR. The staff approved and Odin analysis was used.

What the transient analysis found was performed for the pressurization events for feedwater control or failure, the load reject without bypass and inadvertent HPCI/Level 8 actuation and for the nonpressurization events for the rod withdrawal error, fuel loading error.

These are the results of the LOCA calculations done by GE. GE performed --

MR. THOMAS: Excuse me. You can see the core, the numbers for --

MS. BROWN: Your numbers?

DR. WALLIS: Well, you gave me the DCT but you didn't give me the oxidation or anything like that on the SER. There are three criteria.

MR. RAZZAQUE: we say there is less than --

DR. WALLIS: It doesn't say anything about it at all as far as I can see.

MR. RAZZAQUE: Normally, we don't talk about that because it is so --

DR. WALLIS: It is small.

MR. RAZZAQUE: It is standard thing, I think. Most of the time there are --

DR. WALLIS: There are three criteria. Three are three criteria, though. It's nice to have them tabulated. You didn't tell me what it was before the operate either. You just said the change was small, but I didn't see how big it was.

MR. RAZZAQUE: Also, the PCT's match. And usually PCT's --

DR. WALLIS: But you say in the SER, you say --

MR. RAZZAQUE: --below point one.

DR. WALLIS: -- there's a small change. Now, how much did it change?

MR. RAZZAQUE: You know, what I'm saying is if the PCT is below point 200 --

DR. WALLIS: I know that, but --

MR. RAZZAQUE: -- which is well below, then the oxidation rate usually is below point --

DR. WALLIS: Not always. That depends on the length of the transient. How long you keep it hot for.

MR. RAZZAQUE: In general, I'm saying.

DR. WALLIS: But, but are you going to give me that number?

MR. RAZZAQUE: We can't guarantee that. Otherwise, there wouldn't be any operation.

DR. WALLIS: Are you going to tell me that number, nor not?

MS. ABDULLAHI: We will look it up and give it to you. One second.

DR. WALLIS: Not important to put it in the SER? It's one of the three criteria, right? There are three criteria. One likes to see them enumerated and values attached to them.

MS. ABDULLAHI: Correct. You're talking about --

DR. WALLIS: You say there's a small change. I'd like to know how much the change is.

MS. ABDULLAHI: You --

DR. WALLIS: How much is the change in

PCT?

MS. ABDULLAHI: You want to know EPU?

DR. WALLIS: Why do you just say it's small without giving the evidence?

MS. ABDULLAHI: Okay.

DR. WALLIS: SER should be complete. Otherwise, the reader says it's small, and there's no number.

MS. ABDULLAHI: I think we know that in the improvement in the SC, but I, right now, what I will try, like to do --

DR. WALLIS: What was it?

MS. ABDULLAHI: -- is give you what the pre-EPU and the post EP -- you have the PCT for 105 and you have the PCT at 120.

DR. WALLIS: Different fuel.

MS. ABDULLAHI: Correct. I'll try to look it up. I have a document in front of my hand and, and I'll see if I can get that --

MR. RAZZAQUE: I have the information here for the calculation, which is in the PUSAR. And it's .3 percent. Seventeen percent is the limit.

DR. WALLIS: Yes. Okay, so it's well within the limit.

MR. RAZZAQUE: Well within the limit, yes.

DR. WALLIS: Does it say what the PCT is for 100 percent?

MR. RAZZAQUE: 105 percent, the PCT is --

DR. WALLIS: One hundred percent.

MR. RAZZAQUE: Eighteen forty five.

MR. SIEBER: You probably didn't calculate it --

DR. WALLIS: They didn't calculate it for rate? They must have it in, so there's no -- okay, so it's a new reactor, then. They didn't have any calculation for 100 percent power.

MR. RAZZAQUE: For 105 percent there is a value for oxidation --

DR. WALLIS: There's no value for 100 percent.

MR. BOLGER: This is Fran Bolger from GE. And there was no calculation of PCT for 100 percent.

DR. WALLIS: For 100 percent. So it's a new reactor, really.

MR. RAZZAQUE: 105 and 120.

DR. WALLIS: Then there's no baseline, right?

MR. SIEBER: Every reload is a new reactor. A different configuration.

DR. WALLIS: Yes, but this 105 percent is from a fictional power that's never existed and never been calculated as best as I can make out.

MR. SIEBER: There you go.

(Laughter.)

CHAIR BONACA: I would like to point out that the comments that have just been made are really appropriate. The SER was extremely qualitative.

Very little qualitative information. I mean I know I have to go back to original documents. I have to look at the calculations. Fortunately, we had all of them available.

We shouldn't have to do that. It comes down to results of analysis. I think the SER should be complete in that sense.

And the SER really was not very specific. A lot of qualitative statements. Which means that we have to really believe on trust; simply you say, we say, we buy it. So, I think I second the --

DR. WALLIS: So when you increase the power, the limiting PCT goes down?

The small break sounds wonderful. One is a small break and presumably a large break even lower, 120,

MR. SIEBER: Very easy to do that. All you have to is change the fuel design.

If you put more in smaller tubes, it's going to go down.

DR. ABDEL-KHALIK: For completeness, what is the maximum PCT for a large break at 120 percent power?

MR. SIEBER: All we know it's small.

MR. RAZZAQUE: The licensee calculated it at 1805 and our calculation gave 1800, which tends to be lower for 105.

DR. ABDEL-KHALIK: Could you physically explain the reason why --

MR. RAZZAQUE: I can try. If you want physical explanation is that the profile is flattened from 105 to 120. Okay, when the profile is flattened, you have a redistribution of the flow.

One line is that the average bundle will now have less flow, so the redirection of the flow towards the peak bundle so there are two competing phenomena and the peak bundle is going on.

One is that the peak bundle power increases a little bit. The average bundle is --

DR. WALLIS: That's right.

MR. RAZZAQUE: But the other one increases about 5 percent.

DR. WALLIS: The peak goes down for the

bigger proportion of the core. It's likely to reach closer to it. That's what's happening.

MR. SIEBER: Boilers are different than PWR.

MR. RAZZAQUE: So that explains why it goes down if provided it is a large break. That's what we are saying. Usually, in large break that happens. In stored energy, it is still important.

DR. CORRADINI: May I ask since I've been watching all these thermal-hydraulics -- so is there somewhere in the behind the scenes documents that identifies the difference between the average and hot channel so I could know the root cause of what Graham is suggesting. Or what you guys are both agreeing took which is instead of 50,000 -- one quarter of the 50,000 are at this temperature. Now there's a half of them are at a lower temperature. Do you see my point?

Where is that done or is that only done in the hot channel?

MR. RAZZAQUE: Every bundle increases by 20 percent, directly proportional to the power.

The big bundle shouldn't increase at all because it's complete flattening of the curve from 105. In reality, it increases a little bit five to seven percent.

DR. CORRADINI: But there is nothing though that bridges that gap, in the sense that there's a computation of the average bundle and peak bundle stuff. There's nothing, right?

MR. SIEBER: You can calculate the profiles, but at each power level it is different because of void fraction varies.

DR. BANERJEE: I guess the main reason you are getting a reduction is you've got a G14 fuel, 10 by 10, so the stored energy is much lower? Not much lower, but somewhat lower.

DR. CORRADINI: Can I turn to the GE folks --

DR. WALLIS: I don't understand that about the fuel, because I thought the fuel you put in there was the 120 percent fuel. It's going to be --

MR. RAZZAQUE: G13 and G14, right?

MR. SIEBER: There is a mixture of fuel. The outer edge has got the --

DR. WALLIS: Aren't you going to run this reactor at 120 as soon as --

MR. SIEBER: As soon as you've got the chance.

DR. WALLIS: The same fuel. I don't understand the two different fuels here.

MS. BROWN: Bill, would you like to comment on the type of fuel and how it's going to be run?

MR. STOREY: Well, as I said earlier, this is Greg Storey. The core design is identical, either for the 105 or the 120 percent design. So it's just -- the control rod patterns and operating strategy will be based on the particular power level, but there's no difference in the loading pattern at all.

DR. CORRADINI: So can I just ask you then a question? So is there background information that identifies what is being suggested as the reason it goes down? That is, there's essentially a redistribution of the power shape and I have a larger population of the channels at a higher, at a different, at a higher temperature?

MR. BOLGER: This is Fran Bolger from GE. The hot bundle, the SAFER/GESTR methodology places the hot bundle on the LHGR limit. That LHGR limit is unchanged and therefore that maximum power is the same at the EPU analysis and the 105 percent analysis.

With respect to the sensitivity of the DVA LOCA to the power level change, there is some discussion of the phenomena associated with that in our topical report for constant pressure power uprate.

What the staff has been discussing as far as the average bundle and its impact on the DBA LOCA is essentially correct.

DR. WALLIS: So how do these two fuels, 13 and 14 come out? I thought the 13 was on the periphery?

MR. BOLGER: The calculations with the SAFER/GESTR methodology are done independently for the two different fuel types. The SAFER/GESTR calculation is done with the G13 core, an average core and the G13 hot bundle and another SAFER/GESTR calculation is done with the G14 core and a G14 hot bundle.

DR. WALLIS: The idea is then you are free to load it anywhere you want?

MR. BOLGER: That's correct.

DR. WALLIS: But in reality, it's GE14 over most of the core, isn't it?

MR. BOLGER: That's correct.

DR. WALLIS: And it doesn't seem to be an issue because this temperature is so low.

MR. SIEBER: You could almost bathe in it.

(Laughter)

MS. BROWN: With that, let's go to Slide 12. For Unit 1, the staff when to Browns Ferry to review the licensee's large and small break LOCA using

RELAP-5 and I believe this is what Jose had mentioned before.

And the staff performed an independent analysis to --

DR. WALLIS: You used RELAP-5? You didn't use TRACE?

(Laughter.)

DR. CORRADINI: Please, let it go.

DR. WALLIS: I'm trying to clarify.

DR. BANERJEE: What did you get?

MS. BROWN: The staff sensitivity studies showed top peak actual power --

DR. BANERJEE: Are we basically --

DR. WALLIS: One hundred.

MR. RAZZAQUE: A couple of objectives of these RD calculations and also we look for any new information that we could get. As far as information, we did confirm that the small break is the limiting at 120. There's a certain power level between 105 to 120 through large break limiting to small break limiting. I think we understand that also, quite.

Other information was that the CE has been clearly bumped as 2100 according to staff calculation where there is 1830. And again, this 2100 is primary reason is that intentionally very conservative models were used, like, for example rod rot radiation during the dry period was conservatively --

DR. WALLIS: So if you increase the power, it switches to small break limiting.

DR. BANERJEE: Correct.

DR. WALLIS: Which means that having a transition break size wouldn't do you any good --

I'm trying to think what this means for another issue. A small breaks limiting, then there isn't some incentive to have a transition break size presumably for this kind of reactor.

DR. BANERJEE: There are always two peaks. Why are these peaks becoming larger?

MR. RAZZAQUE: The reason we think that in the small break analysis we have seen that the decay period is longer. Because of the additional decay heat in the 120, plus this 105. And that is often a little delayed injection of ECCS and that makes a difference.

DR. ABDEL-KHALIK: There is a big difference between 1830 and 2100 and presumably both of these calculations are Appendix K type calculations.

Could you explain?

MR. RAZZAQUE: I would be glad to. One is that the GE code and other is the RELAP-5 Code. There is several code differences.

More important is that we have used bounding very conservative models. To give you an example, the ADS, the number of ADS that are operating actually six, but we use five, and we cut down one ADS. just to make things conservative. And the radiation -- rod rot radiation, the transfer model was conservative designed.

DR. ABDEL-KHALIK: But what is the purpose of doing independent calculations by the staff?

MR. RAZZAQUE: Again, I think the couple of reasons. One is to confirm the GE's results.

DR. ABDEL-KHALIK: Right, but if you sort of use different assumptions then what the applicant has used, you will get different answers?

MR. RAZZAQUE: We do. We get unreasonable assumptions. But we are saying -- we are trying to find, for example, the limiting metal header, the limiting power pitting factor which turned out to be top-picked, rather than rate-picked. Originally, licensee calculated the limiting by mid-picked which was not limiting. We found it out. We went back to licensee and asked them to recalculate their LOCA analysis based on the top-picked accident and they did. And the result on the LOCA analysis is it did increase. Not by a significant margin, but it did increase, 35 degrees, as far as I remember. But there's another value to the calculation and the other is confirmation is the main reason or if we come up with new information like we came up with information -- at least in this case.

There is some benefit to it.

DR. BANERJEE: Did you do some calculations like this for the Appendix R calculation that they did?

MR. RAZZAQUE: We -- the Reactor Systems Branch didn't do that. The PUSAR, if you look at it, what you have in the PUSAR is calculated area approved to operate at 105 percent value of the design basis, which is 1485, a staff-approved value which is less than 1500 so --

DR. BANERJEE: They're getting close. Well, they explained that this morning. Because they took a different decay heat primarily, you know.

MR. RAZZAQUE: So usually in this case, if you use less --

DR. BANERJEE: I'm just asking did you do any confirmatory analysis?

MR. RAZZAQUE: No, we did not. We just

did the LOCA, the limiting LOCA for the regular LOCA.

CHAIR BONACA: Let's move on.

DR. BANERJEE: How much oxidation did you get? MR. RAZZAQUE: Oxidation was in the PUSAR. I'm sorry, if it wasn't in the SER, but it is for 105, the oxidation is 2 percent and for EPU is 3 percent. The limit is 17 percent. For hydrogen generation, 105 is .1 percent; EPU is 2.1 percent and limited 1 percent; 10 times more than the limit.

DR. CORRADINI: Say again, I'm sorry.

MR. RAZZAQUE: The hydrogen percent cool water metal water reaction is 10 CFR 546 limit is one less than 1 percent.

DR. BANERJEE: So the reason it is interesting is of course if you have more bundles close to 2100. You'd expect that you'd get --

DR. CORRADINI: It's an exponential, so it's not clear.

CHAIR BONACA: Give me those numbers again?

MR. RAZZAQUE: Which ones?

CHAIR BONACA: The hydrogen.

MR. RAZZAQUE: Hydrogen generation is .1, less than .1 for 105 and also .1 for EPU.

CHAIR BONACA: I'm a little surprised

because --

DR. WALLIS: The oxidation goes up. I think the oxidation goes up at 120. You're at a higher oxidation.

MR. RAZZAQUE: We haven't checked those. Id' say -- the person who actually did our in-house LOCA calculation is in a jury duty which looks like a higher priority than this one, so he's not here. But I don't know whether he has calculated the hydrogen generation. I mean whether he has that information, but he didn't give me the information to provide, at least now for this.

DR. BANERJEE: These confirmatory analyses were not in our package, were they. Okay. I haven't seen it.

DR. WALLIS: I didn't see it in the SER.

DR. BANERJEE: If it was, it escaped me.

DR. ABDEL-KHALIK: The 92 bundles that you got from unit two, these were once-burned?

MR. STOREY: This is Greg Storey. They're actually a mix of once and twice burned. They're 56 GE13s that are 2-cycle burned and 36 1-cycle burned GE14.

DR. ABDEL-KHALIK: So that the pre-oxidation that you're calculating based on burnup must be very low, if your maximum oxidation is two percent.

MR. RAZZAQUE: Oxidation is less than two percent. It always is less than. It's also hydrogen generation less than point one, so the comparative energy in both cases less then one. They were less than one case than the other case.

DR. ABDEL-KHALIK: What is the pre-oxidation value for the burnup associated with the twice-burned bundles that you plan to put in?

MR. STOREY: Well, this is Greg Storey. We did do inspections of that fuel and we did not see anything unusual in terms of corrosion or oxidation on that fuel.

DR. ABDEL-KHALIK: But there must be a value associated with burnup.

MR. BOLGER: This is Fran Bolger. The LOCA calculation of oxidation doesn't include addition of the pre-transient oxidation.

DR. ABDEL-KHALIK: But the 17 percent limit does.

MR. BOLGER: The issue of whether pre-transient oxidation is considered is, I believe, part of the discussions on Friday, this week. Currently, the SAFER/GESTR methodology does not include addition of the pre-transient oxidation.

DR. POWERS: Well, I don't think discussion to include it or not is part of tomorrow's discussion. discussion. I believe that's a closed issue.

DR. WALLIS: So you could confirm that the peak clad temperature, not the criteria didn't really confirm, confirm it within 300 degrees or something. That's not a very good confirmation.

DR. BANERJEE: But they used more --

DR. WALLIS: But you used some more, you used somewhat different assumptions, as my colleague was saying here. So, you confirmed that they met the criteria. You didn't really confirm it itself, because you didn't do the same calculations, they had different assumptions.

DR. BANERJEE: Well, I think they, they also contributed something by showing that the --

DR. WALLIS: Small breaks.

DR. BANERJEE: -- peaking factor, the small breaks, so I think it's useful to to this.

DR. WALLIS: Yes.

MS. BROWN: Well, I think we just went over everything on this slide. Let's go to --

DR. WALLIS: To the hydro rating, yes.

MS. BROWN: Yes, let's look at what we

have left. Let's see if we have anything left for ATWS. Because I believe Jose went over this discussion as well earlier --

DR. WALLIS: When we did the ATWS, did you talk about what the operators have to do? I mean, the operators have to maintain the levels. And I think that this was somehow confirmed by running simulators.

MS. BROWN: Yes, sir. I believe Mr. Huang --

DR. WALLIS: Going to talk about that? They're under more pressure, presumably, at the higher -- is it time to act?

CHAIR BONACA: This should go on the agenda tomorrow.

DR. WALLIS: We can talk about it tomorrow.

MS. BROWN: They're available to talk about it now, if you'd like.

MR. MARCH-LEUBA: Anytime you want.

DR. WALLIS: There is a reduced time for operation action?

MR. MARCH-LEUBA: A concern of the 120 percent uprate. You conceivably can be up 20 percent --

DR. WALLIS: Things happen quicker, do

they, and they --

MR. MARCH-LEUBA: Well, things happen quicker --

DR. WALLIS: Right, right

MR. MARCH-LEUBA: And we went to the simulator and spent a whole afternoon in Browns Ferry testing those features and I recommend that you go and --

DR. WALLIS: Did they know that they were going to be tested on ATWS when they went into the simulator?

MR. MARCH-LEUBA: The simulator had several ATWS and had real operators executing the real emergency instructions --

DR. WALLIS: It makes all the differences what the operators are expecting when they go into the test.

MR. MARCH-LEUBA: It does, it does. Everybody knows that most accidents happen between Christmas Day and New Year's Eve and there's a reason --

DR. WALLIS: And they could mis-diagnose it if they didn't know it was an ATWS.

MR. MARCH-LEUBA: But even then, if you do go and see an ATWS in the simulator, you will find out that it's not as stressful as we would think. The operators are really calm, and they have plenty of time to do the work --

DR. WALLIS: That's because it's a simulator, yes.

(Laughter.)

MR. MARCH-LEUBA: A real ATWS is going to have three or four more events happening at the same time. But, what we're asking the operator to do is not unreasonable. That was our conclusion.

DR. WALLIS: But he does have less time.

MR. MARCH LEUBA: Really not.

DR. WALLIS: Not significantly? No. Okay.

MS. BROWN: All right. Were there any more questions on ATWS?

CHAIR BONACA: Tomorrow, we have a full session on operator actions, right?

MS. BROWN: Yes, sir.

CHAIR BONACA: Your going to inform us on the breadth of training and --

MS. BROWN: Yes sir, TVA --

CHAIR BONACA: -- we'll pick up that issue again, risk and human performance.

DR. WALLIS: The ATWS pressure is getting close to the limit, isn't it?

MS. BROWN: Yes, sir.

DR. BANERJEE: ATWS, you said the amount of time doesn't vary relative to the operator -- doesn't vary very much. Why is that?

MR. MARCH-LEUBA: There are two criteria of relevance to an ATWS. First is the pressure, the peak pressure as you get the pressurization wave and that happens within 10 seconds. The operator has nothing to do with it. And then you have the long-term cooling of the containment in the suppression pool. The operator has everything to do with that. And that long-term is on the order of 20 to 30 minutes. So the operators have plenty of time to do everything they need to do.

DR. BANERJEE: But it does shorten in terms of the 20 percent uprate, correct?

MR. MARCH-LEUBA: If you think about it from the 20 percent uprate, as long as you stay on the MELLA line, the very first thing you do is trip your suppression pumps. And you go back to another circulation to exactly the same power you were before the power uprate. So you have to start looking at the second-order effects like power distributions and things like that, but on first order approximation, the moment you trip the pumps, you follow the same line and you end up exactly where you were before the uprate.

DR. BANERJEE: But don't you get much larger instability in those cases?

MR. MARCH-LEUBA: Not with EPU on first-order approximation. MELLA plus is completely different. And we'll be talking to you about MELLA plus. But EPU stays on the same raw line. We have more out there to see. But the moment you trip the pumps on EPU you end up where you were before the upgrade.

DR. ABDEL-KHALIK: Now, the 1500 psig, I mean, you indicate that these values are less than 1500 psig, which is the ASME limit. Is that correct?

MR. THOMAS: Estimated level, C-limited.

DR. ABDEL-KHALIK: Now, 1484 is awfully close to 1500. So, what is the uncertainty in the initial pressure?

MR. THOMAS: Initial pressure is the --

DR. ABDEL-KHALIK: I mean, you assume that the plant is operating perfectly, whatever, the pressure is going to be there, is absolutely no uncertainty in the initial pressure?

MR. THOMAS: The initial pressure is

assumed to be 1020 psig --

DR. ABDEL-KHALIK: What is the instrument uncertainty?

MR. THOMAS: Normally, you know, the reactor vessel normally operates about 470 psig. But the analysis assumed 1020 psig. So there is a considered review function there actually.

DR. ABDEL-KHALIK: But the review pressure is 1050, is that correct?

MS. ABDULLAHI: This is Zena Adbullahi. That was analysis usually used as nominal assumptions. And we would have to go through it. But, because it's an ATWS and not a transient, not a, you know, requiring a SAVETAL, it's based on nominal conditions. There are some conservative assumptions in there and we had, before had them listed what was those conservative assumptions. And some of them were how fast they open, which SRVs open first and things like that and the lift tolerances, but generally it's nominal.

So, yes, we have seen and we talk about this every time because we're both uncomfortable with it at 1499 in some plants.

DR. POWERS: I understand that there's some margin built into the 1500. Local things set up so that if it's 1499 --

DR. KRESS: Even if it's 1501, it's probable.

DR. POWERS: Look, probably, but it does not pass muster.

MR. RAZZAQUE: And there's a LOCA-related event.

DR. POWERS: Say it again?

MR. RUBEN: A LOCA-related event.

DR. POWERS: Yes.

DR. WALLIS: You can lose a football game by one point.

DR. POWERS: It's the end of the season, so what?

CHAIR BONACA: So this wraps up your presentation today?

MS. BROWN: Yes.

CHAIR BONACA: I don't think we'll want to go on the table today. I think we'll do that tomorrow. But I would like to ask members if there are additional questions here on the presentation we got today?

DR. WALLIS: Well, I had about fifty I never got to ask, but I was sure my colleagues did a very good job --

DR. KRESS: We asked every one of them.

DR. CORRADINI: Sanjoy took over.

DR. POWERS: Actually, we corrected three of your questions and asked them properly.

(Laughter.)

CHAIR BONACA: All right, if there are no further questions then we will pick up the issue again tomorrow at 8:30.

We are recessed until tomorrow morning.

(Whereupon, at 6:40 p.m., the meeting was adjourned, to reconvene tomorrow, Wednesday, January 17, 2007 at 8:30 a.m.)