Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee Reactor Safeguards Subcommittee on Power Uprates	
Docket Number:	(not applicable)	
Location:	Rockville, Maryland	
Date:	Tuesday, April 25, 2006	
Work Order No.:	NRC-982	Pages 1-396

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MEETING OF THE SUBCOMMITTEE ON POWER UPRATES
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BEAVER VALLEY POWER STATION EXTENDED POWER UPRATE
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TUESDAY, APRIL 25, 2006
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The subcommittee meeting convened at the Nuclear Regulatory Commission, Two White Flint North, Room T-2B3, 11545 Rockville Pike, at 8:30 a.m., Richard B. Denning, Chair, presiding,

SUBCOMMITTEE MEMBERS PRESENT:

RICHARD B. DENNING, Chair
SANJOY BANERJEE
ACRS Consultant
THOMAS S. KRESS
OTTO L. MAYNARD
JOHN D. SIEBER
GRAHAM B. WALLIS

ACRS STAFF PRESENT:

RALPH CARUSO

FIRSTENERGY STAFF PRESENT:

A.R. BURGER

FENOC

MATT CERRONE

Westinghouse

DON DURKOSH

FENOC

KEN FREDERICK

FENOC

DAVID FINK

Westinghouse

CHUN FU

Westinghouse

NORM HANLEY

Stone & Webster

JOSH HARTZ

Westinghouse

GREG KAMMERDINER FENOC

BRETT KELLERMAN

Westinghouse

JAMES LASH

FENOC

MARK MANOLERAS

FENOC

CHRIS MCHUGH

Westinghouse

BRIAN MURTAGH

FENOC

MAHESH PATEL

FENOC

JACK PENKROT

Westinghouse

PETE SENA

FENOC

GEORGE STORLIS

FENOC

MIKE TESTA

FENOC

DENNIS WEAKLAND

FENOC

NRR STAFF PRESENT:

TIMOTHY COLBURN

RICHARD LOBEL

JIM MEDOF

SAMUEL MIRANDA

JOHN PARILLO

PAT PATNAIK

LYNN WARD

A-G-E-N-D-A

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

8:32 a.m

CHAIRMAN DENNING: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates. I'm Richard Denning, Chairman of the Subcommittee.

Subcommittee members in attendance are Tom Kress, Otto Maynard, Jack Sieber, Graham Wallis who is virtually at the moment, but will be physically here later and our consultant Sanjoy Banerjee, who also seems to be virtually here.

The purpose of this meeting is to discuss the extended power uprate application for the Beaver Valley Power Station. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC Staff and the Beaver Valley Power Station licensee, FirstEnergy, 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 April 12, 2006.

A transcript of the meeting is being kept and 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 received any requests from members of the public to make oral statements or written comments.

We think that the agenda that we're going through today and tomorrow is quite well balanced towards addressing the principal interests and interests of the Subcommittee. We know that the power uprates will result in some eating into safety margins. WE need to know where that's occurring and become convinced that the margins are still adequate.

This is a very quantitative Committee. The Staff's review of the application must be comprehensive, our view must in many sense be in many aspects be more focused. We'd like you to spend minimal time on the aspects of plant safety that are not effected by the uprate. The nice thing about having the safety analysis results today is that there is always tomorrow to ask you to come back and give us more detail.

You'll notice our room has been modified somewhat over the last couple of weeks. I hope that everything's going to work okay. I know the screen isn't perfect, but we will proceed.

Now I would like to turn the meeting over to Mr. Colburn of the NRC Staff to begin.

MR. COLBURN: Thank you, Mr. Denning.

My name is Tim Colburn. I am a Senior Project Manager in the Division of Operating Reactor Licensing in the Office of Nuclear Reactor Regulation. I'm assigned to the Beaver Valley Power Station, Units 1 and 2.

During the next two days presentations will be made by the Staff and the licensee concerning background information related to the application, plant changes associated with the application and fuel and core design changes, safety analysis including methodology used for conducting those safety analysis, discussion of non-LOCA events and large break LOCA.

The Staff and licensee will conduct discussions of the safety analysis.

The safety analysis discussion will also include discussions by licensee and the Staff on small break LOCA, long term cooling and boron precipitation, containment over pressure credit and dose analyses.

The Staff will also provide a discussion of the containment analysis associated with the conversion from sub-atmospheric to atmospheric conditions and its dose analysis and implementation of the alternative source term.

CHAIRMAN DENNING: I think you can just arrow down, Tim, if you want to there.

MR. COLBURN: The Staff and the licensee will also discuss the materials and reactor vessel integrity issue associated with the safety evaluation for the power uprate.

On day two a discussion of the balance of plant issues associated with the power uprate, flow accelerate corrosion, vibration, corrosion erosion and risk evaluation will be conducted by both the Staff and the licensee.

Operations and testing associated with the power uprate including human factor issues, power ascension testing and the licensee test plan for basically what amounts to a two phrase implementation of the testing will be discussed. And then conclusions of the licensee and the Staff.

The licensee had several license amendment applications that they had submitted prior to the power uprate which were needed to support the power uprate review. These included:

Steam generator allowable value setpoint changes, which were to eliminate concerns the Staff had with measurement uncertainty;

A containment conversion license amendment application to convert the Beaver Valley Power Station 1 and 2 containments from sub-atmospheric to atmospheric conditions;

Best estimate LOCA methodology approval for the large break LOCA analyses;

Steam generator replacement for Beaver Valley Power Station Unit 1 only. Replace the previous steam generators with the Model 54F steam generators; and

Implementation of the relaxed axial offset control methodology for both units.

These amendments have all been approved and all have been implemented for Unit 1. Implementation of some of these will be for Unit 2 in the fall of 2006 outage.

The licensee's submittal originally was sent in on October 4, 2004. It had numerous supplements. The licensee had submittals on February 23rd and June 14 of 2005 which were necessary to consider the application a complete application. The Staff issued its acceptance review of the licensee's application in July of 2005 and indicated that it would be reviewing the application for basically within a one year time frame.

The licensee's application requested an increase in reactor power from the current 2689 megawatts thermal to 2900 megawatts thermal. This is approximately an 8 percent increase in power and is considered an extended power uprate.

The Staff plans to issue its safety evaluation and amendment on or about the end of June 2006. The licensee plans to implement the extended power uprate for Unit 1 within 120 days of receipt of the approval. And for Unit 2 in a phased approach concluding with the completion of balance of plant upgrades including a turbine upgrade in the spring of 2008.

What I'd like to do now is turn the presentation over to the licensee's site Vice President Mr. Jim Lash for his opening remarks.

MR. LASH: First off, my name is Jim Lash.

CHAIRMAN DENNING: No. Hold on just a

second.

MR. LASH: Okay. First off, my name is Jim Lash, site Vice President of Beaver Valley Power Station.

Good morning, Mr. Chairman and distinguished members, ACRS consultants. This morning I'd like to provide a brief introduction and some background to the Beaver Valley power uprate. Our decided outcome is to provide you with sufficient information and answer all relevant questions regarding the Beaver Valley power uprate so that you can form appropriate decisions and recommendations to the NRC Commissioners.

We've built this presentation to cover a number of areas effected by the uprate in areas that we believe are of interest to the Committee in fulfilling the desired outcome of these proceedings.

We have a full agenda of items to cover in the next two days, and that is shown here on this slide.

I'd like to introduce the presenters from FENOC. Other than myself will be Pete Sena will provide an overview. He is the Director of Engineering at Beaver Valley.

Mark Manoleras on plant changes. He is

the Design Engineering Manager at Beaver Valley.

A.R. Burger will do reactor fuel and core design. He is a supervisor of core design.

Ken Frederick will address safety analysis. He is a nuclear safety analyst.

Dennis Weakland materials and reactor vessel integrity. He's a fleet material representative.

Mike Testa the mechanical plant VOP. He's the EPU Project Manager.

Risk evaluation Colin Keller, who is the supervisor of the PRA group at Beaver Valley.

And finally the operations and testing aspects of this project will be Don Durkosh, who is a senior reactor operator.

Each presenter will describe their area of expertise and introduce any subject matter experts that they'll use during the course of their presentation and at the time of their presentation.

In addition to the presenters we have subject matter experts here from Beaver Valley as well as some contractors, organizations supporting us, Westinghouse and Stone & Webster.

The balance of my comments will briefly focus on the history of Beaver Valley, the extended power uprate time line, the peer units experienced with power uprate and the oversight of our power uprate project.

Okay. Beaver Valley units are three loop Westinghouse PWRs that achieved commercial operations in 1976 for 1776 Unit 1 and 1987 for Unit 2. The original core licensed power was 2652 megawatts thermal or 2660 megawatts thermal NSSS power. And both units have currently implemented a 1.4 percent uprate to 2689 megawatt thermal or 2697 megawatt thermal NSSS power. This uprate credited the improved feedwater flow measurements implemented in the fall of 2001.

CHAIRMAN DENNING: Let me ask you just a couple of questions related to the differences between the two designs. Obviously there's a long distant time differential between when the two were started. But even before we get into the steam generator replacement there are some fairly significant differences. And you have, I gather, separate simulators for the two. Can you give me just a little feeling as to what the principal differences are just at this point prior to?

MR. LASH: Well, they're principally the same design, however there is a time difference between the implementations of those units so there is a difference in some aspects of the systems for both units.

CHAIRMAN DENNING: Yes.

MR. LASH: We do qualify operators independently for those two units, so we have dual simulators to maintain a bank of SROs qualified personnel for each unit. We're not dual licensed on the plant.

The specific design aspects I think we'll get into in the safety analysis and how we've treated those differences later on with some of the other presenters.

CHAIRMAN DENNING: Yes. But the operators are licensed to operate just one or the other unit?

MR. LASH: That is correct?

CHAIRMAN DENNING: And do some of them learn how to do both or --

MR. LASH: We have had personnel licensed on both units. For example, Pete Sena who will follow me was licensed on both Unit 1 and Unit 2.

CHAIRMAN DENNING: But any particular time they're dedicated towards one or the other?

MR. LASH: Predominately the SROs are qualified and maintain a license, an active license, only on a single unit.

CHAIRMAN DENNING: Thanks.

MR. LASH: A time line of Beaver Valley. This is a recent time line starting in 1998. The first item I'd point out there is that FirstEnergy Nuclear Operating Company was formed in December of 1998. And that operating company has now matured to a fleet organization and is staffed to support all functional areas at the three nuclear stations Beaver Valley, Davis-Besse and Perry.

FENOC Corporate is currently charged with providing governance and oversight of all station activities.

Beaver Valley was purchased by FirstEnergy from Duquesne Light & Power Company in late 1999 through an asset swap of fossil fire units for the nuclear station.

In early 2000 FENOC implemented a full potential program for Unit 1 and Unit 2 with a key objective of managing design margins and increasing the electrical output of both units. The EPU project, which is a subset of this potential program, has updated the station's analyses to include the selected final design of the Unit 1 steam generators, which were already referenced as the Model 54, which were recently installed during the last outage at Unit 1. We'll talk about that briefly in a moment.

In total, the EPU project and its supporting projects, steam generator replacement, containment conversion, best estimate LOCA and others that will be referred to this morning span a period of 6 years. As a result of the project, Unit 1 and Unit 2 have established a revised baseline of supporting plant analyses that will be used to manage design margins for the remaining life of both units. This is in keeping with the original premises of the parent full potential program that I spoke of earlier.

I previously mentioned the recently completed outage at Unit 1. Let me briefly touch on the scope and significant accomplishments of that outage.

This is a picture of our containment. You can see that we replaced all three steam generators in this outage. By the way, this outage completed April 19, last Wednesday at 2018. And Unit 1 has achieved 100 percent power, full power operation on Sunday at 1400 hours and it remains at 100 percent power.

So during the outage we replaced the steam generators and the reactor vessel head with a modified simplified design, and the major accomplishments in these replacements is obviously the elimination of the Alloy 600 aspect of materials that were associated with the older components.

Now shown here, because it's not in containment, is the main unit generator rotor was replaced. It has a short. We replaced it. And the main unit generator itself was rewound.

Now there were many other activities, but I won't go through all of those.

I would point out that the average time frame to do a steam generator outage first time for a station is about 82 days. Beaver Valley accomplished this outage in 65 days. And I believe that to be a very positive indication of both the strength of the organization as well as the level of planning and the preparedness for that outage.

The larger power uprate which we're referred to and why we're here today, 8 percent was initiated in mid-2000 and used an initial scoping phase to determine the best approach and the optimum targeted licensed power level. As a result of the scoping evaluation, a target power level of 2900 megawatts thermal or 2910 megawatts thermal NSSS was selected.

As you can see, that target aligns us very well with our peer three loop Westinghouse units that have already previous uprated. We benchmarked closely these units, both their approach to uprate and their operating history since its implementation. We feel that collectively using the experience of these stations gives us confidence in the approach we have chosen. Specific examples of benchmarking in implementation would be the use, for example, of the specification for Model 54 steam generators used at Farley Station and now at Beaver Valley. And the phased approach to implementing the uprate, which we will be discussing in greater detail later on in the presentation.

MR. CARUSO: Have you ever considered doing the stretch uprate?

MR. LASH: No, we have.

MR. CARUSO: I mean, I don't know if you've ever --

MR. LASH: We've never discussed it.

MR. CARUSO: Never discussed that?

MR. LASH: Next slide, please.

In the area of oversight, executive and senior management oversight of the project has been in place since its inception. The site leadership team has been closely involved, and this team includes the site Vice President, myself, the Plant Manager and Engineering Director.

A FENOC executive leadership team has also provided oversight and this includes our Senior Vice President of Engineering currently Dan Pace who bring unique experience in operating activities rom his previous role at Entergy.

Oversight of the engineering and licensing process that supports this uprate has been directly performed through implementation of the mentioned boards, committees and assessments. And an example of the independent assessment you find at the bottom there would be the NPR Associates for a review of our uprate supplemental.

That completes my introductory comments. And if there are no other questions, I will turn over the presentation to Pete Sena, the Director of Engineer for Beaver Valley. Thank you.

MR. SENA: Good morning. Again, I'm Pete Sena. I am the Director of Engineering at Beaver Valley. My previous position at Beaver Valley was as the Operations Manager and also as a senior reactor operator at both units. So I did hold a senior reactor operator license, active license for both units simultaneous. So I'd take a stand working both units one at a time, so I do have a unique perspective as far as the differences between the two units. And when we come into questions with respect to some of those specifics during the presentation, I can speak to it. And also we have one of our shift managers here, George Storlis, who is also licensed in both units, however at a different times. So we will be able to provide the Chairman with additional detail as you request.

I will speak to principally the preparations for the uprate, the general criteria, the project team and the technical reviews. And before I do so, I do want to comment that we at Beaver Valley did attend the previous Subcommittee meeting that Ginna participated in. We found that to be extremely helpful as we prepared for our presentation, and we have tailored our presentation we believe to what the Committee desires. We will focus heavily on our safety analysis so you can understand the margins that remain following the uprate. We will be going into great detail on our LOCA and our limiting non-LOCA transients, such as a loss of feedwater and uncontrolled rod withdrawal accident. So as we go into those details, I think you'll appreciate what margins do remain.

All right. As you can see from this next slide there were several amendments that have prepared Beaver Valley for the power uprate. And again, the uprate project was a full potential project initiated back in the year 2000. Just that some of these amendments will be touched on as we go through the presentation, but I would like to speak to several of them right here.

The positive moderator temperature coefficient was previously approved and implemented back in the year 2002. So what that has enabled us to do is to gain operating experience on startup with a slightly positive MTC throughout the years now that we've had several cycles of operation. I personally was the first SRO to perform a reactor startup with that slightly positive MTC.

Now that experience and the lessons learned have been captured and formalized for subsequent crews and subsequent startups.

Also the alternate source term, we will speak about that again in the future, but we did selectively apply AST to several accidents such as a fuel handling accident LOCA, rod ejection. And what this permitted Beaver Valley to do was to eliminate or retire circle systems, and one in particular would be what's called the control room air model pressurization system which, Mr. Sieber, you may remember that that has challenged the plant in the past with an inadvertent actuation which had resulted in a dual unit shutdown, a tech spec 303 shutdown. So there were several benefits towards that selected implementation.

Finally, containment conversion and best estimate LOCA, those amendments were previously approved by the NRC in the first quarter of this year. On the containment conversion, there is an industrial safety benefit that the site has realized with respect to more frequent and safer containment entries at power to allow for inspection of various components as we see fit.

CHAIRMAN DENNING: What did you lose on that in terms of -- you know, it's never been absolutely clear to me why they were sub-atmospheric and what the perceived benefits were of that and how this might impact it.

MR. SENA: What I'd like to do is defer that because we have an entire presentation on the containment conversion and we're going to go through that in great detail.

CHAIRMAN DENNING: Okay.

MR. SENA: A couple of things, though. We did not change the containment design pressure of 45 pounds. We did not change the structural design temperature of 280 pounds. But there are several aspects that were a benefit to the plant. For example, the increased initial pressure provides additional back pressure for the loss of coolant accident. However, but we still need to meet our designed pressure of 45 pounds. So we will go into the detail on that particular amendment.

MEMBER SIEBER: Maybe before you soot away from that, the idea early on was to be able to build a smaller containment, spend less money on concrete and rebar. And if you started out at a sub-atmospheric pressure, the presumption was that you would not reach as high in ultimate pressure. On the other hand, the containment was built as a large dry strong containment and the sub-atmospheric really didn't change things all that much.

One of the advantageous, though, is you get increased head to the sump because you're starting at higher pressure, which could assist in the recirculation phase of a LOCA accident.

I have a question about the positive moderator temperature coefficient. It's quite common to have a positive moderator temperature coefficient when the plant is cold. I presume that you're still positive when the plant is hot early in core life?

MR. SENA: It's --

MEMBER SIEBER: And that goes away sometime probably a third of the way through core life?

MR. SENA: At about 30 percent power. We're really starting off with zero feedback, around a zero moderator temperature coefficient upon initial criticality and the initial power ascension. Once you come up to around 30 percent power and increase power, it then starts --

MEMBER SIEBER: It goes the other way?

MR. SENA: -- inching it in the positive direction.

MEMBER SIEBER: Oh, okay. And does that stay throughout the life of the cycle?

MR. SENA: Well, again throughout the cycle the same. As --

MEMBER SIEBER: At burndown it changes?

MR. SENA: -- you bring up the boron -- right. Then you're progressing towards a more traditional negative MTC.

MEMBER SIEBER: Right.

MR. SENA: To maybe minus 4 or minus 5.

DR. BANERJEE: The increased pressure, does that lead to increased temperature in the sump water?

MR. SENA: I'll tell you what we're going to do is we're going to go through specifically the need for containment overpressure during our presentation.

DR. BANERJEE: Right.

MR. SENA: We currently at Unit 1 do credit containment overpressure and will continue to credit overpressure. And the onset of the accident, Mike, what's our initial steam temperature about 280 degrees?

MR. TESTA: This is Mike Testa, the Project Manager at Beaver Valley.

Pardon, could you repeat?

MR. SENA: The initial temperature for the assumptions for containment overpressure, for containment sump temperature?

MR. FREDERICK: You want to answer. I'm here. This is Ken Frederick.

When the initial pumps start, the sump temperature is around 260 degrees.

DR. BANERJEE: And what would have been in the sub-atmospheric case?

MR. FREDERICK: It's roughly the same. I'll show you some slides later that show you how that changes.

DR. BANERJEE: So you say it doesn't change?

MR. FREDERICK: It goes up a few degrees, not much. The initial pressure change does not really impact the transient conditions and some of that's due to some methodology changes that we've incorporated in its analysis.

DR. BANERJEE: Okay. You'll speak of this in detail, right?

MR. FREDERICK: Yes.

MR. SENA: Yes. We have a specific presentation talking specifically towards containment over pressure.

Finally on the best estimate LOCA again, that was recently approved. Both containment and conversion and best estimate LOCA were both approved first quarter of this year and have been implemented at Unit 1 upon the completion of the Unit 1 outage.

At Unit 2 we have a full outage, those two amendments will be implemented on the completion of the Unit 2 outage.

CHAIRMAN DENNING: Was that essentially to be able to accommodate the uprate?

MR. SENA: Yes, it was.

All right. The best estimate LOCA that we're speaking of is not the ASTRUM methodology utilized by Ginna, but the more traditional COBRA/TRAC. And we will discussing best estimate LOCA in a future presentation. But it is the same methodology used by Gravewood, Byron.

Next slide, please.

Again, is the key elements of the uprate. I think I've spoken to these already with respect to the containment conversion and best estimate LOCA. And, again, we will go into great detail on analyses.

Next slide.

And the message about this slide is simply that we at Beaver Valley did not forge new ground here. We followed the same methodology used by other utilities in their uprate. There are no new or unlicensed industry methodologies being applied here.

Next slide.

As Mr. Lash said, this was a Beaver Valley led project. The ownership remained with us at the site. We did have corporate oversight, corporate oversight and governance. But, again, the ownership remained with our experienced site personnel.

We provided overall project management and direction. But, again, we had significant support from our teammates, from Westinghouse and Stone & Webster. And, again, many are here today in support and are various subject matter experts that we may call upon throughout the presentation.

Next slide.

Again, we at Beaver Valley, even though we did have vendor support, we reviewed and approved the design inputs and performed detailed owner acceptance of each vendor calculation.

Finally, I do want to make a comment in recognition of the NRC Staff. The NRC review and challenges and various RAIs were very detailed, very challenging and did result in a better project here today. And in particular, the Staff audits that were performed either at Westinghouse or at Beaver Valley in the area of PSA, safety analysis and radiological assessment did significantly help us to come to closure on many open items and also significantly streamlined the review process. So we do appreciate that from the NRC.

Next I'd like to introduce Mark Manoleras. Mark is the Manager of Design Engineering at Beaver Valley. Mark will be looking at the plant modifications that we had done and plan to do at Beaver Valley.

Thank you.

MR. MANOLERAS: Thank you, Pete.

My name is Mark Manoleras. I'm the Design Engineering Manager at Beaver Valley. I've been the Design Engineering Manager since 2002. My department's responsibility has been the oversight and performance of the modification packages and the safety analysis associated with the uprate.

At this time I'd also like to mention in the back, Mahesh Patel. Mahesh Patel is my lead electrical engineer. He will be here to support the second part of my presentation.

Next slide, please.

I'd like to discuss three areas today. I'd like to discuss the plant modifications that were performed to support the safety analysis for the power uprate. Many of these modification packages were performed to satisfy initial conditions in the safety analysis. I will touch on the modification package, discuss it briefly and we will discuss each modification in great detail when we come up to the safety analysis section.

I'd also like to spend a few minutes to

talk about the electrical system summary. The electrical system summary we will spend some time on it. There was very minor changes associated with the electrical system associated with the power uprate. So we will touch on it in my portion of the presentation.

And we will also discuss the use of operating experience. The operating experience that we touched on during the project.

Next slide, please.

As you see, this is the start of a list of our plant modifications that were performed for the power uprate. I will discuss each modification and then I will identify its status whether it had been implemented at Unit 1 or Unit 2.

The first modification is replacement of our charging/safety injection pump rotating assemblies. This modification extends our pump runout flow limit and it improves high head margin and it improves small break LOCA margin.

At Unit 1 we have replaced all three of our charging pumps. At Unit 2 we have currently replaced two of those three pumps, and currently are planning to replace our third pump prior to our Unit 2 outage, which will implement some of the amendments that you saw previously.

The next modification package I would like to discuss is the addition of fast acting feedwater isolation valves at Unit 1. These valves reduce containment pressure following a mainstream line break inside containment. And they also provide redundant isolation capability for feedwater isolation events. These feedwater isolation valves are already existing at Unit 2.

I'd also like to discuss briefly the addition of aux feed cavitating venturies at Unit 1. These venturies minimize mass input to containment and reduce aux feed flow on a feedline break and maintain minimum flow to the intact steam generator. These cavitating venturies already exist at Unit 2.

We also added a reactor cavity drainage port at Unit 1 to facilitate post-accident drain to improve NPSH performances as pump draw from the sump. We intend to install that reactor cavity drainage port at Unit 2 in our next outage.

We eliminated our quench spray cutback feature and it's not longer required due to the containment analysis at Unit 1. This quench spray cutback does not exist at Unit 2.

Additionally, we replaced our steam

generators at Unit 1 and that includes the narrow range level transmitters. We increased the narrow range span. And we'll talk about that in great detail in the non-LOCA analyses that follow.

DR. BANERJEE: Why was it necessary to put those auxiliary cavitating venturies?

MR. MANOLERAS: Yes. What we did that for was we wanted to make sure that we minimized the mass input to containment following that feedline break. We wanted to do that. Basically reduce the mass addition to the containment following a feedline break.

DR. BANERJEE: And that came about because of the uprate?

MR. MANOLERAS: That's correct. Basically part of the containment analyses.

MR. TESTA: Yes. This is Mike Testa again from Beaver Valley.

As Mark said, Unit 2 plant already had that feature, had cavitating venturies installed in the auxiliary feedwater system.

When we looked at Unit 1 we wanted to again, as Mark said, help support the revised mass and energy release to the containment for feedline break and a steamline break. And it also helps to protect the pumps from run off condition. So early on in the project we decided to install those cavitating venturies and then credit those in the mass and energy release for the containment analysis.

DR. BANERJEE: I guess a more general comment is I see a list of things you're doing, but I don't have a clear picture of why you do them. And does this come out later on or --

MR. MANOLERAS: Yes. Actually, when we get to the safety analysis section of the presentation we will identify which modification packages satisfy which initial conditions of those analyses.

DR. BANERJEE: Anyway, if you could just briefly mention the why, that would be very helpful.

MR. MANOLERAS: Okay. I will do that.

DR. BANERJEE: Why do you replace the steam generator? Maybe it's obvious, but we'd like to know.

MR. MANOLERAS: Yes. For example, our Unit 1 steam generators were the oldest steam generators in the country. We basically had very limited tube plugging margin there. So we installed new steam generators. The generators that we installed actually do not have any tubes plugged. So, obviously, that was the reason that we did that Unit 1. That's an example.

DR. BANERJEE: Okay.

MR. MANOLERAS: Okay. Next slide, please.

We replaced our high pressure turbine at Unit 1 with a turbine with all reaction design. At Unit 2 we're going to do that also. We basically needed to do that to basically maximize our megawatt capacity; that's why we did that.

At Unit 1 we already installed stakes in our main condenser to eliminate any vibration issues. We intend to install those stakes in the Unit 2 condenser so we do not have any flow induced vibration issues there.

MEMBER SIEBER: What's the tube material at Unit 2 condenser.

MR. TESTA: It's stainless.

MEMBER SIEBER: Stainless. Yes. Is the original.

MR. TESTA: Yes.

DR. BANERJEE: And the steam generator tubes?

MR. TESTA: Steam generator tubes?

MEMBER SIEBER: 690 for Unit 1, 600 for Unit 2

MR. MANOLERAS: 600. And we go into great detail. We have a materials presentation. We'll go into great detail on that.

At Unit 1 we did not have to replace our cooling tower fill. We had adequate cooling tower fill. We did not have to replace that.

At Unit 2 we put in a high efficiency fill.

MEMBER SIEBER: You may want to tell what cooling tower fill is.

MR. MANOLERAS: Basically this is the material in the cooling tower that helps I guess the heat exchange capacity or capability of that cooling tower. So the fill material will allow the dissipation of heat in the cooling tower, I guess is the best way to describe it.

DR. BANERJEE: Why does it do that?

MR. TESTA: Again, this is Mike Testa.

For the cooling tower on the circ water side of the cooling tower, basically you pump the water into the tower and the water will rain down, basically, in effect over this fill. And the fill it helps to aerate, in effect break up the water and help aerate it. That way when you bring the natural draft of the tower through it, it'll help remove heat.

MEMBER SIEBER: In Unit 1 it looks like venetian blinds.

DR. BANERJEE: Huh?

MEMBER SIEBER: In Unit 1 it looks like venetian blinds and the water cascades down through it and the air is going through at right angles.

I take it that all the asbestos that was in there is now gone?

MR. MANOLERAS: That's correct.

DR. BANERJEE: Then the last point raise set pressure, is that just for the cycle or what?

MR. MANOLERAS: No. We intend to make a permanent change. We've actually made that change. We raised that setpoint to the MSR reheater relief valves. We did some analyses, BOP analyses that identified that we would have limited margin error. So we went out and we retested and reset our MSR relief valve setpoints.

DR. BANERJEE: Margin to what?

MR. TESTA: This is Mike Testa again.

As Mark said, we redid the heat balance for the power uprate and we looked at the operating pressure at the MSR. The operating pressure in effect went up about 10 pounds. Okay. We had relief valves that were set originally at 250 psig. And then because of the uprate and they increased in operating pressure of about 10 pounds, we modified the relief valves to relieve at 260. So in other words, the operating pressure went up 10 pounds. We raised the set pressure 10 pounds.

MEMBER SIEBER: So you're still way under the design pressure?

MR. TESTA: Yes. Yes. Yes.

DR. BANERJEE: Do these relief valves latch open or do they close as the power goes back and forth, the pressure?

MR. TESTA: They basically have a set pressure. They will pop at that set pressure.

DR. BANERJEE: Right. And then--

MR. TESTA: And then they'll release and then reset.

DR. BANERJEE: At some other pressure?

MEMBER SIEBER: Will, you blow down for probably 5 percent.

MR. TESTA: Yes.

MEMBER SIEBER: It will close and then if the pressure goes up again, it'll open again at the original set pressure.

DR. BANERJEE: It doesn't factor?

MR. TESTA: No, does not.

MEMBER SIEBER: Hopefully.

MR. TESTA: Again, we've already done

this. We have operating experience on Unit 2 in the past spring outage. We've already done that modification. And we've had no issues, no problems with that.

MEMBER SIEBER: The pressure is not high and there's a lot of volume there, so --

MR. TESTA: Yes.

MEMBER SIEBER: -- it shouldn't change.

MR. MANOLERAS: The next slide, please.

We increased the CD of our main feedwater control valves. At Unit 1 we replaced the control valve trim. At Unit 2 we are replacing the feed reg valves. We did that basically to improve their operating range and also to help stabilize our steam general level control.

MEMBER SIEBER: What kind of trim did you put in Unit 1 feed reg valves? It originally had what they called the hush trim, which was about the third mod.

MR. TESTA: This is Mike Testa.

We put in hush trims on Unit 1.

MEMBER SIEBER: That's what was in there.

MR. HANLEY: This is Norm Hanley from Stone & Webster. Repeat your question, please

MEMBER SIEBER: Ten or 15 years ago it had hush trim in it and there was a lot of problems with the valve on ability to control the low flows. The valve was modified several times, all three of them were. I'm wondering what you did recently?

MR. HANLEY: The recent change really didn't modify the trims that you have in there now. It just increased the CV. The operating experience with the latest set of trims was well. So we didn't go into a redesign of the trim. It was just get us more CV so we'd get a better operating range.

DR. BANERJEE: Well, how did you get a better CV?

MR. HANLEY: Yes. We went back to the vendor. The original valves, I think, had a large of CV, about 1100. And right now we've got 1050 in there. So the valve could accommodate. So the vendor designed the CV to give us 1050 maximum and allowed us a good operating range during the power uprate. The values should operate between 75 and 80 percent open during the uprate.

MEMBER SIEBER: It seems to me the way that the plant was originally built those valves were throttled quite a bit. Since it has electric feed pumps instead of turbine drive feed pumps, turbine driven feed pumps have basically a constant differential across the reg valve. With electric pumps at low loads there's a big pressure drop there. It's very hard on the valves; that's why the valves were modified several times to try to tone down the energy dissertation. After the hush trim was installed, that was pretty much the end of the feed reg valve problem.

MR. HANLEY: In fact, we just installed them in Unit 1 and we did a start up and the valve behaved very well during start up.

CHAIRMAN DENNING: Be sure to speak into the mike.

MR. HANLEY: All right.

MR. SENA: This is Pete Sena.

Just one item, Mr. Sieber, that the operating crew from this last start up at Unit 1 did comment that the feed reg valve control was the best they had seen at low power operations for start up. There were no anomalies.

MR. MANOLERAS: Okay. Jim had already discussed the replacement of the rotor and the rewind of the starter.

We additionally modified our heater drain control valves at both units to increase operating range and improve capacity. And we replaced our instrument replacements for main steam and feedwater flow for the higher flow ranges that we'll discuss later in the safety analysis presentation.

CHAIRMAN DENNING: Before you move on to that, I do have a little digression. And that is regards to sump blockage. At some point, I presume in the near future, you're going to be making changes or can you tell us what the status is of that?

MR. MANOLERAS: Sure.

CHAIRMAN DENNING: And what the character of the changes will be and when they'll occur.

MR. MANOLERAS: Sure. We currently have about 120 square foot sumps. We're going to be expanding those sumps by a factor of at least 10. We are going to put much larger passage strainers in at Unit 1 and Unit 2. We intend to install the passive strainer system at Unit 1 in the upcoming outage and at Unit 1 in our next outage. We will also install that passage system at Unit 1.

We are currently doing the analysis associated with the strainer design, putting them in the actual mix of the insulation and boric acid, the mix, doing the testing of our strainer design to make sure that all the assumptions that we put into the analysis are put as far as DP across the strainers and whatnot. So we're going right down the path of the GSI-191 requirements.

CHAIRMAN DENNING: So the change for Unit 2 it will occur prior to the power uprate, is that true?

MR. MANOLERAS: It's going to be installed in our next outage, the physical modifications to the sump, which our next outage is when we intend to begin our escalation and our power uprate.

CHAIRMAN DENNING: Whereas in Unit 1, of course, it would follow?

MR. MANOLERAS: Unit 1 we intend to perform a mid-cycle uprate and our next refueling outage before we went to the full power uprate, we would have the new sump in.

CHAIRMAN DENNING: Yes. And what kind of thermal insulation do you currently have?

MR. MANOLERAS: We have several types of thermal insulation. We have a metal-reflective. The majority of our containment we do have metal-reflective. We also have a material it's called, it's abbreviated name is CALSIL. It's a material that is like a plaster of Paris type of material that encapsulated with --

CHAIRMAN DENNING: We're familiar with it.

MR. MANOLERAS: Okay. So we have some of that.

And we have several other types of insulation also.

DR. BANERJEE: Do you have NUKON?

MR. MANOLERAS: Pardon me?

DR. BANERJEE: NUKON?

MR. MANOLERAS: NUKON? That's a term that I am not familiar with. So I don't want to say that we don't, but it's not a prevalent use of material in our containment.

CHAIRMAN DENNING: You don't have a fiberglass?

MR. MANOLERAS: Fiberglass?

CHAIRMAN DENNING: Fiberglass? Fiberglass mats in any places.

DR. BANERJEE: Fibrous material?

MEMBER SIEBER: Yes, they're like blankets

MR. MANOLERAS: Yes. We don't have significant quantities of any fibrous material. We would have very limited fibrous material, maybe in an application like around a loop stop valve where we would have -- and I'm talking very, very small quantities of that where we would have some space limitations. Like we would pack it in around a valve, but it would be in very small quantities. And what we're going to do is in each refueling outage we're going target and take a hard look at that material to see if we can get it out of there and replace with metal reflective.

DR. BANERJEE: What are you insulating your steam generators with?

MR. MANOLERAS: The replacement steam generators? We replaced the CALSIL associated with those steam generators and put metal reflective in during this last outage in every area that we could.

DR. BANERJEE: All the new steam generators will have metal reflective?

MR. MANOLERAS: That's correct.

MEMBER SIEBER: Unit 1.

MR. MANOLERAS: In Unit 1

CHAIRMAN DENNING: At Unit 1.

MR. MANOLERAS: When we replaced our steam generators -- to make sure we're very clear. At Unit 1 when we replaced our steam generators we put in metal reflective insulation and we took out those materials that have been identified in that GSI-191.

CHAIRMAN DENNING: Will there be a future replacement of steam generators at Unit 2 or how much margin do you still have there?

MR. MANOLERAS: We have significant tube plugging margin at Unit 2. I'm sure that in our long range plan that's something that we'll look at. But at the present time we have not targeted that replacement. We have significant margin at Unit 2.

CHAIRMAN DENNING: And plant life extension is still to come?

MR. MANOLERAS: That's correct. We are currently working on what we term to be a license renewal submittal.

DR. BANERJEE: How do you control pH?

MR. MANOLERAS: Our chemical addition system we currently use an additive. It's sodium hydroxide, NaOH.

DR. BANERJEE: Do you have any aluminum in the containment?

MR. MANOLERAS: Yes, we do. We keep track. We have a very detailed program to keep track of aluminum in containment so that we don't have, for example, hydrogen generation is always a big concern. So we have a very detailed program to keep track of any aluminum that we place in containment. We have very small quantities of aluminum in containment. We know where it's at.

DR. BANERJEE: Well, will you address

these issue related to the sump and the change from sub-atmospheric to atmospheric pressure and all that sort of thing? Is there going to be a talk on this sometime?

MR. MANOLERAS: You know, there's actually a very detailed presentation that we've put in on the containment conversion submittal.

DR. BANERJEE: And will it be done, something?

MR. MANOLERAS: It will be done this morning, I believe, or early in the afternoon. And I believe we actually brought a slide to show our conceptual design for our new sump strainer. We actually have a picture of our sump strainer that we are currently designing.

MEMBER SIEBER: But the conversion of the containment to an atmospheric containment is already approved and implemented?

MR. MANOLERAS: That's correct. That license amendment has been approved and it has been implemented at Unit 1.

MEMBER SIEBER: Okay. Before you jump into the electrical system, when I was reading through the application in the SER, particularly the marked-up tech specs, I stumbled across a place where you are eliminating the negative rate trip?

MR. MANOLERAS: That's correct.

MEMBER SIEBER: What's that have to do with EPU or anything else, or did you figure that was just a good chance to get rid of something you didn't like?

MR. MANOLERAS: Well, you hit right on the head. The negative rate trip was not used in our plant safety analysis. Additionally, there was an owners group program to eliminate that trip. We took this opportunity to implement that. That will reduce surveillance burden for us at the station.

MEMBER SIEBER: Yes. The reason why it was in there originally, though, was in case you dropped a rod that the plant would trip before you started operating with a big imbalance in the core. There was a reason to do that. Did you change your operating procedures to tell the reactor operator to trip the plant when it gets to that condition?

MR. DURKOSH: This is Don Durkosh from Operations.

Yes, we have immediate operator actions for any dropped rod.

MEMBER SIEBER: Okay.

MR. DURKOSH: If we have more than one

dropped rod, we immediately trip the reactor.

MEMBER SIEBER: More than one?

MR. DURKOSH: More than one, that's correct. More than one.

MEMBER SIEBER: So what kind of offset do you get if you just drop one rod all the way in in a critical area, do you know? Has anybody done those calculations? That's why we had the trip so you wouldn't have to do the calculation.

MR. MURTAGH: This is Brian Murtagh from Design Engineering.

The Westinghouse WCAP that evaluated the elimination of the negative rate trip essentially, from what I remember, it was if you evaluated the most reactive rod worth and that were to trip, you would still not be tripping on negative rate. So because we do not credit that in the safety analysis, that's why it was eliminated.

MEMBER SIEBER: Okay. But that's different for every cycle. The Westinghouse WCAP was done for the envelop of cores that you could design and could put into that kind of a plan. I take it during the reload safety evaluation that's analyzed again?

MR. PENKROT: This is Jack Penkrot from

Westinghouse.

We do evaluate the dropped rod.

MEMBER SIEBER: Okay.

MR. PENKROT: For all the values up to 1,000 pcm. Whenever the negative rate trip was eliminated, we increased the span that we evaluated from zero to 500 to zero to 1,000. We're able to show that peaking factors are adequate to handle any dropped rod.

MEMBER SIEBER: Do you know the number and the date of the WCAP so I could read it?

MR. PENKROT: I don't have that information.

MEMBER SIEBER: Well, could you get it?

MR. PENKROT: Oh, yes. Sure.

MEMBER MAYNARD: This trip has been eliminated at a number of plants. In fact, for most plants most rods, a single rod, wouldn't give you the negative rate trip anyway. But you have procedures for recovering that rod --

MEMBER SIEBER: Yes, I know.

MEMBER MAYNARD: -- that limit. You can't just pull it right back out and go to operating. So you do have an off normal procedure that controls the recovery from that to keep you within your safety analysis.

MEMBER SIEBER: I'd still like to read the WCAP.

I was just trying to figure why it was stuck in with all this other stuff as opposed to standing out there by itself because it really is not related to EPU or the containment change or alternate source term or anything else. It's just out there.

MR. MURTAGH: Mr. Sieber, this is Brian Murtagh again.

I can certainly get you that WCAP, a copy of the WCAP.

MEMBER SIEBER: Well, we probably have it. If the Staff's approved it, it's here. All I need is the number. It'll be in our file.

MR. MURTAGH: Okay. We'll do our best to try to find that number.

MEMBER SIEBER: If you want to give it to me, that's even better. You know, I'm in love with paper. You know, I get tons of it every week.

CHAIRMAN DENNING: Thank you.

MR. MANOLERAS: Yes. I believe Chris --

MR. McHUGH: Chris McHugh from Westinghouse.

I have that number on my laptop. I'll

look it up and give it to you in a couple of minutes.

MEMBER SIEBER: Thanks.

MR. MANOLERAS: Thank you, Chris.

Any further discussion before I move on to electrical system?

We added the slide here to discuss the electric system impacts, the actual system impacts because of the power uprate were actually extremely minimal. I brought Mahesh Patel, as I mentioned before, in case any questions are beyond me and we'll have Mahesh answer those.

Our initial electrical system design is robust. We basically took a look at all of our electrical components. We looked at our Unit 1 transformer. We did not have to do any upgrades to our Unit 1 transformer.

Our Unit 2 transformer we had to upgrade that cooling system. And we did upgrade that cooling system. We have several cycles of operation now with that transformer and that cooling system. And the modification packages that we did make basically had their intended results. So our cooling system for our transfer has been upgraded.

Our isophased bus duct, one of the issues is OE and the industry looked as isophased bus duct temperatures. We went out and did extensive maintenance our bus duct cooling systems at both units to make sure that the material condition of those cooling systems -- material condition was there. We did not require any modification packages to those cooling systems.

We did install temperature indicators in those cooling systems so that we can do operator rounds and ensure that the bus duct cooling system meets its performance.

We obviously have operating limits on our grid voltage, which we did not have to change in reactive loads to look at post-trip voltages on our buses. We did not have to make any modifications to any of those limits because of the uprate.

Our grid we did detailed grid stability studies and Beaver Valley can both receive and accept trips on the grid without any impact. And we did not effect our 4-hour station blackout coping study because of the uprate.

MEMBER SIEBER: In Unit 1 are you replacing the main unit transformer or are you going to use the one that's still there?

MR. MANOLERAS: We're going to use the existing transformer.

MEMBER SIEBER: You know that that had faults in it a couple of times?

MR. MANOLERAS: We have had to replace that transformer. We had an inadvertent spraydown of that transformer several years ago and it was replaced, as you remember.

MEMBER SIEBER: Well, the replacement transformer, the internal impedance was such that it represented an unusual condition on the grid. I presume that you know that.

MR. MANOLERAS: Yes, we do.

MEMBER SIEBER: But it called into question the breaker capacity if you had to trip that transformer free from the grid interrupting capacity.

MR. MANOLERAS: Mahesh Patel.

MR. PATEL: Yes. This is Mahesh Patel.

When we had a fault on the original transformer, we had it built with a little bit higher than the previous transformer. And we evaluated the breaker capacity and that reduce the fault coming from the system. And that makes the breaker capacity. And the newer transformer is rated is 1058 MBA at 65 degree temperature rise.

MEMBER SIEBER: Okay. Thank you.

MR. MANOLERAS: The next slide, please.

Yes. In this last slide I'd like to just go over some of the industry OE and things we looked at. Each specific presenter will discuss the specific OE in his area.

We looked at, obviously, vibration issues. We talked about staking the condenser. We looked at things like the turbine control system running with valves wide opened. We looked at the isophase bus duct cooling capacity and transformer cooling. And Jim discussed earlier we installed the leading edge technology -- the leading edge flow meter for measurement uncertainties.

Each presenter will discuss OE in his particular area.

If there are no additional questions, I would like to introduce A.R. Burger, our fuels analyst.

MR. BURGER: Thank you, Mark.

Good morning.

As Mark indicated, my name is A.R. Burger. I'm currently the supervisor of core design and physics support. And I'm responsible currently for the design oversight for not only Beaver Valley, but also the Perry and also Davis-Besse unit.

I have supporting person Jack Penkrot.

He's a Westinghouse core designer. He's done core design for both Beaver Valley units for quite a few years.

To give you a little background, I started out in '82 as a reactor engineer down at Beaver Valley. Starts physics testing at Unit 2 and power central testing. Moved on to the fuel procurement and contract administration in the '90s. And '98 to 2004 I became the core design, reload design coordinator for Beaver Valley interfacing with all the contract administration in implementing the core designs. And currently I'm in the supervisor position.

I've been involved in EPU since the inception back in 2000 and so we've preparing in the core design area for that.

What I'm going to touch upon is the fuel design and the core design aspects.

This represents the current design that we have Beaver Valley. It's called the robust fuel assembly. It's the same array, 17 by 17 as the previous, which was a Vantage 5H that we had prior to the RSA. We maintained the enrichment, the geometric fuel geometry, the cladding, the loading of the uranium, axial blanket height; all that has remained the same.

The changes with the RFA that we've put in, we have six cycles operating history on the RFA. We implemented back at Unit 1 starting with cycle 15 in 2001 and that Beaver Valley introduced in cycle 10 2002. We did that for several reasons, one being the uprate coming. We saw that coming and so we wanted to get in to look at the RFA design. There's intermediate flow mixers on the top three spans. That will give you GMD margin that we would implement to give us for the uprate.

MEMBER SIEBER: You have to change the pressure drop across the core?

MR. BURGER: Yes.

MEMBER SIEBER: By how much?

MR. BURGER: There was a couple of pounds difference.

MEMBER SIEBER: That's pretty much.

MR. BURGER: And that's why you have a transition core penalty in that time. We've now got fuel, RFAs in the entire core so we have a whole core of that. We don't have any transition penalty and things like that going on.

MEMBER SIEBER: Well, you have flow distribution problems when you have a mixed core.

MR. BURGER: Right.

MEMBER SIEBER: On the other hand it seems to me the core flow went up instead of down in your list of parameters. And I would expect it would have gone down with this kind of fuel by a little bit.

MR. BURGER: Well, they're going to go into that in the safety valve section.

MEMBER SIEBER: The pressure drop across the steam generators, the new steam generators, is less, right? Is that true? Less than the Model 51s? 54 is less DP than Model 51, is that true?

MR. BURGER: Excuse me. Could you repeat the question, please?

MEMBER SIEBER: Is the pressure drop across the new steam generators, the Model 54, less than the pressure drop across the old steam generators, which is Model 51?

MR. HALL: Yes. This is Jeff Hall, Westinghouse.

That's correct. The Unit 2 generators are Model 51.

MEMBER SIEBER: So you end up with higher DP across the core, lower DP across the steam generators and an overall slight increase in flow for the whole system?

MR. HALL: That's correct.

MEMBER SIEBER: Okay. You just moved the DPs around? Okay. Thanks.

CHAIRMAN DENNING: But of course they would be different for Unit 1 and Unit 2 then?

MEMBER SIEBER: Yes, they are right now because they haven't replaced steam generators in Unit 2.

MEMBER MAYNARD: Well, you'll also be operating at a little bit different RCS temperature, won't you, for your uprated condition?

MEMBER SIEBER: Well, yes. And that comes about because of the change in flow and the change in materials and the change in surface.

MR. BURGER: You have the 576.2 plus or minus a couple of degrees of where we're at currently for the uprate.

MEMBER SIEBER: Right.

MR. BURGER: And they'll go into that in the safety analysis section where we're targeting to go for two and a half for each unit.

MEMBER SIEBER: And your hot leg trip is what? 617, something like that? They would normally be operating at about 610 or 611 on the hot leg?

MR. BURGER: On the hot leg, yes.

MEMBER SIEBER: Okay.

MR. FREDERICK: This is Ken Frederick.

Yes, that's correct, Jack. We'll go over that later in my slides.

MEMBER SIEBER: Well, it sounds like it's the same as Ginna. Same core parameter set.

MR. FREDERICK: In terms of the temperatures, yes, it's very similar.

DR. BANERJEE: Was there any DNB testing done on a prototype bundle or something?

MR. BURGER: Yes, there were supposedly tests done for the RFA by Westinghouse when they originally came out with them in 2002 and 2001. The RFA has actually been out in the industry for quite a few years.

MEMBER SIEBER: Yes.

MR. BURGER: There's 33 plants operating with the RFA fuel design.

DR. BANERJEE: What are these mixes like that give you better performance?

MR. BURGER: They just provide extra flow mixing --

DR. BANERJEE: What are these mixes?

MR. BURGER: They're just an extra grid that's put between the upper grid span. You'll notice they're a little bit thinner than the standard grid and, again, they're must meant to get flow mixing into the assembly so that that's all they're there for. They provide a little bit more structural integrity for the assembly also, a little bit more stiffer assembly.

MEMBER MAYNARD: They just have little pads in them that kind of redirect flow and mix the flow right?

MR. BURGER: Mix the flow right.

MEMBER SIEBER: In a mixed core there are some grids that don't contact the adjacent fuel assembly grid. So from the seismic standpoint it's meaningless.

MR. BURGER: Yes. There is no impact on the seismic parameters.

DR. BANERJEE: And these tests were done in a flow loop they had with heaters?

MR. BURGER: That's right.

DR. BANERJEE: Electrical heaters?

MR. BURGER: I believe they were, yes. The VIPRE loop that they use for Westinghouse.

MR. CARUSO: Yes.

MEMBER SIEBER: Yes.

MR. CARUSO: Westinghouse has a test loop that they run down in Columbia.

MR. BURGER: VIPRE loop down there that they run.

MEMBER SIEBER: Yes. They've been doing that for years.

What correlation are they on now? It used to be --

MR. BURGER: We'll go into that. There's a WRB-2M correlation that they'll be using for the RFA and we'll be implementing that with the uprate. Right now we're not utilizing it. But when we uprate, we'll implement the WRB-2M. And, again, they'll go into that in the safety analysis.

MEMBER SIEBER: And here you can't have a mixed core to implement that correlation?

MR. BURGER: Right. We were going to implement an older design, put it in there. We have to go and use the other correlations which are still applicable.

MEMBER SIEBER: Right.

MR. BURGER: When we originally did the analysis back in 2000 we were going to have a mixed core, but it's delayed enough that we now have a full core of RFAs, so we won't need that.

MEMBER SIEBER: Well, you have to go to the most conservative correlation that you have.

MR. BURGER: Right.

DR. BANERJEE: So the increased power is accommodated by --

MR. BURGER: Why don't we go to the next slide and that will show.

DR. BANERJEE: This increase in DNB?

MR. BURGER: We'll let into it, after this one. This one will show you that the DNB margin and we're going to use the WRB-2M correlation, as I mentioned, for the IFMs being in there. The RFA also, as I mentioned, provides a better grid design for grid-to-rod fretting issues. Beaver Valley and the industry had had issues with grid-to-rod fretting and so we went to that RFA design early on for fuel failures to get rid of those.

We also at that time, there was issues with incomplete rod insertion in the industry. So the RFA provides a slightly increased the I2 giving a stiffer assembly and more margin --

MEMBER SIEBER: A larger diameter guide, too?

MR. BURGER: Yes. The IB stayed the same and the OD increased slightly.

MEMBER SIEBER: Okay. And I take the grid-to-rod fretting you're using the -- you have two dimples and two springs made out of Zircaloy. And those springs as the become irradiated, they relax.

MR. BURGER: Right. Correct.

MEMBER SIEBER: To the point where they aren't springs anymore?

MR. BURGER: Yes. They redesigned those assemblies so they had more contact surface area with the springs. And we have not had any grid-to-rod fretting with those assemblies and we have three cycles of operation. So they basically have gone through a full lifetime of those.

MEMBER SIEBER: That wasn't really an issue at that plant anyway.

MR. BURGER: What? At Beaver Valley?

MEMBER SIEBER: Yes.

MR. BURGER: Yes. We had grid-to-rod fretting issues with the 5H, yes.

MEMBER SIEBER: Oh, okay.

MR. BURGER: Yes. We had fuel failures associated with that.

DR. BANERJEE: But to get the increased power out, does the surface area in contact with the coolant increase or not?

MR. BURGER: No. We'll go to the next slide. What we'll do is we did conceptual core designs for the uprate conditions. We did that both with the Westinghouse codes, the ANC codes. We also run in-house down at our offices. Basically to get the increased power out we're going to go from equilibrium to core cycles of 18,800, 20,200.

We have had cycles up above 20,200 just because of the way the outages were scheduled. Beaver Valley Unit 2 cycle 10 was 20,400. So we have had cores where there's much energy as we'll be doing for the uprates.

Basically your linear heat generation rate's going to go up. So the fuels all stayed the same on the surface area and everything else. Just put --

DR. BANERJEE: So your heat flux goes up?

MR. BURGER: Right. And it's in the same vein as the others that we mentioned earlier, kilowatt per foot is in that same range --

DR. BANERJEE: So what allows you to get more heat out of the same surface area fuel?

MEMBER SIEBER: Higher temperature.

MR. BURGER: Higher temperature. Yes.

DR. BANERJEE: No, no. I mean from the point of view of limits?

MR. BURGER: Our peaking factors will

remain the same.

MEMBER SIEBER: You got closer to the point of 200.

DR. BANERJEE: What?

MR. BURGER: The peaking factors were to remain the same. What we did was to get more margin on the fuel is we put in the IFM, so that gives DNB margin and --

DR. BANERJEE: So you get your DNB margin by doing better mixing?

MR. BURGER: Right. In the hottest --

DR. BANERJEE: And this is a fairly well understood process?

MR. BURGER: Yes.

DR. BANERJEE: How much increase in DNB do you get?

MR. BURGER: About a 20 percent increase.

DR. BANERJEE: Remarkable. And what about the LOCA limits?

MR. BURGER: We'll go into that later in the safety analysis and they'll actually show you the markups of where the DNB margin limit, where the correlation is, how much safety margin in. And we'll go into that in the safety analysis.

DR. BANERJEE: So basically you have the

same surface area fuel, the same subdivision and you're getting 10 percent more power?

MEMBER SIEBER: Yes.

DR. BANERJEE: By doing something to the DNB limit and the LOCA limits?

MEMBER SIEBER: Well --

DR. BANERJEE: Is that a correct statement?

MEMBER SIEBER: Well, there's a couple of effects going on. The other thing that gets effected is the number of rods that have an increased peak clad temperature during a LOCA, and usually with an improved core design the approach to the 2200 degrees doesn't change very much, but the number of rods who make that approach does change because you're flattening the power distribution.

MR. BURGER: Right. And you'll see that, as we said, there's going to be 64 more feet assemblies. So to get that extra power out, you'll need more feed assemblies to go into the core. So that's where you're getting extra power; you're going to spread that power out over --

MEMBER SIEBER: That's where you get the neutrons from.

DR. BANERJEE: You're not increasing the

surface area of the fuel? You're just bringing in fresher fuel?

MR. BURGER: Right. Distribute the burnup along the assembly --

DR. BANERJEE: So that means you get a high heat flux, too, right? So the issue really, and hope you'll address is, is to understand how you can get more power out of the same fuel, basically the same fuel surface area. Maybe it's by sharpening the pencils and doing a few experiments, but we want to be convinced that this is really not. Maybe other people have done that, but you would have to do it at some point.

MR. FU: Okay. This Chun Fu, Westinghouse, thermal hydraulic design.

So basically you have IFM, it enhance your mixing an in an analysis area we have WRB-2M correlation, which give you 20 percent or even a little more than 20 percent in the margin. So you will see that.

DR. BANERJEE: Yes, we'll look at it. And the basis for it.

CHAIRMAN DENNING: This is probably an irrelevant question, but why didn't you decide to go to higher burnups?

MR. BURGER: Higher burnups?

CHAIRMAN DENNING: Yes.

MR. BURGER: The average actually discharge we're putting in four more assemblies. You'll spread the burnup among those. So the average discharge on the assemblies will remain about the same. So you'll just put that burnup on more assemblies. But you really, the overall will be in the 50,000.

CHAIRMAN DENNING: What's your refueling cycle then?

MR. BURGER: We're on 18 month refueling cycles.

CHAIRMAN DENNING: You're on 18 month refueling cycle?

MEMBER SIEBER: These are cycle burnups as opposed to assembly burnups?

MR. BURGER: Discharge assembly will be in the 50,000 --

MEMBER SIEBER: Right.

CHAIRMAN DENNING: That's what I didn't understand.

MEMBER SIEBER: Which is a moderate. It's sort of in the middle of where everybody's running.

MR. BURGER: Right. Yes. And there's

other plants that are operating at 5.69 and 2900 and they're in the similar area.

MEMBER SIEBER: Right.

MR. BURGER: Next slide.

Our current maximum riching is 5 weight percent. We currently put in a split four of usually 495 right now and 46 enrichment, so it'll be no change to the maximum enrichment that we'll see.

With T_{avg} remaining approximately the same plus or minus 2 degrees of the current, you don't see a whole lot of change in the flux profile on the assemblies.

Again, we're operating with a full core of RFA, full units so we won't have any transition four penalties impacted.

And another item that we implemented was separate from the EPU was RAOC. That was basically to give more operating flexibility to the Operations. They were doing that separately but when we went to the EPU we also incorporated EPU conditions into the RAOC curves that we came up with.

We've now implemented RAOC, start up of Unit 1 here is with RAOC. So they're operating right now with RAOC at the current --

MEMBER SIEBER: That's already been

approved?

MR. BURGER: Yes, it's been approved. Right. And we're actually operating it for the first cycle right now.

MEMBER SIEBER: There are a number of other plants that have already have this.

MR. BURGER: Right. And you have a tech spec out of that one.

MEMBER SIEBER: Usually on the maximum enrichment it's the spent fuel pool that governs how high you can go.

MR. BURGER: Yes. We're currently at five weight percent for both units.

MEMBER SIEBER: Okay. Do you take burnup credit?

MR. BURGER: At Unit 1 we have Borel in the Unit 1 fuel pool and so there's distinct regions for that of where the fuel goes.

Unit 2 we have Borelfex. We're not crediting the Borelfex in there. So we credit the soluble boron in there. And we're trying to get a rerack in there for Unit 2 to get rid of the Borel. Also, to get more room in the spent fuel pool. And that analysis will be done in the late 2009/2010 area.

MEMBER SIEBER: Do you have enough extra spaces to wait that long?

MR. BURGER: Apparently we can go that long. We have submittal later this year for spent fuel criticality analysis to maybe get a better checkerboard pattern out of that and maximize those areas in the pool.

MEMBER SIEBER: Well, the checkerboard pattern ought to spread out the deposition of heat modes, too.

MR. BURGER: Right. Exactly.

MEMBER SIEBER: For obvious reasons. Okay.

MR. BURGER: And that's all I had in the fuel and core design area.

CHAIRMAN DENNING: I think there is something we want to pursue just a little bit here. Because obviously we're on a tight time schedule related to when we're going to have our full Committee. And I see an issue here related to the change in the DNB correlation associated with that mixing. And I can see Sanjoy is ready to jump onto this issue.

I'm wondering how quickly could we get some information on the validation of this revision to the DNB model? And presumably Westinghouse has some results.

MR. BURGER: Yes. That's already been previously approved the correlation. And it's already in use.

CHAIRMAN DENNING: Okay. So that's the other element I wanted to --

MEMBER SIEBER: I think there's a WCAP on that one.

MR. BURGER: Yes, there's a WCAP out there for the WRB-2M right. And then we're applying it now with the use of the VIPRE code and --

MEMBER SIEBER: Maybe we could just get a copy of the WCAP?

MR. CARUSO: I can give you a copy of the WCAP.

MEMBER SIEBER: Oh, okay.

DR. BANERJEE: And it's been applied to this specific fuel?

MR. BURGER: Five or six years ago, yes.

DR. BANERJEE: To this specific fuel design?

MR. BURGER: Yes.

DR. BANERJEE: And at these ratings?

MR. BURGER: Yes.

DR. BANERJEE: Where?

MEMBER SIEBER: Yes, before they sell it they usually have the correlation and have it approved.

MR. CARUSO: The plants are using this that have not done the uprate. Haven't done uprates. They just use it to increase margin to improve their fuel performance. There's a lot of reasons why they would want to use that are --

DR. BANERJEE: So I think we could just review what's being done right now.

MR. CARUSO: I think I can get a copy. I know the guy who did the review.

DR. BANERJEE: Review the review?

MR. CARUSO: We could talk about that offline. But that's not hard to get for you.

DR. BANERJEE: Okay.

CHAIRMAN DENNING: Okay. Very good. Thank you very much.

We're now going to take a 15 minute break and we start up again at five after 10:00.

(Whereupon, at 9:52 a.m. off the record until 10:09 a.m.)

CHAIRMAN DENNING: Okay. We're now back in session. And we're going to start up with Mr. Frederick on safety analysis.

MR. FREDERICK: I wanted to thank the Committee for allowing us the opportunity to come and talk to you.

As the slide says, my name is Ken Frederick I'm the lead safety analyst at Beaver Valley. By background I've worked at Beaver Valley for 27 years, most of that time has been spent in the engineering department, only a few years in the operations.

For the last five years I've been assigned to the uprate project and also the other projects that we mentioned here, the containment conversion and the best estimate LOCA.

Next slide.

Just to give you a brief objective for what we consider the safety analysis of the plant. First of all, we want to demonstrate that we have compliance with all the regulatory limits and the acceptance criteria . And also we want to show that Beaver Valley has adequate safety margins at the EPU conditions.

Next slide.

So basically we'll be talking about the specific analysis areas that are listed here as well as some of the methodologies and the setpoint changes and design parameters associated with the EPU conditions.

This slide shows the design parameters for the uprate condition as well as the current operations. Basically here we're showing that the mass flow through the reactor essentially is unchanged. The thermal design flow, which is the tech spec value which is in volumetric units gallons per minute stays the same. So in order to get increased power out of the core, we have to increase the enthalpy rise across the core. So you see an increase in the hot leg temperature and a slight decrease in the cold leg temperatures.

CHAIRMAN DENNING: And the difference between EPU low and EPU high is what?

MR. FREDERICK: We've analyzed a range for T_{avg}. The low temperature being 566.2 and the upper end is 580 degrees.

CHAIRMAN DENNING: And you would expect at different times to be operating throughout that range depending upon what was?

MR. FREDERICK: Yes, we have target values. And you want to pull up the backup slide?

This slide shows the target values that we're intending to operate at, although we could revise the T_{avg} parameter in that range that we have the analyzed, 566.2 to 580.

For Unit 1 you can see T_{avg} as compared to the current operation will go up a little less than 2 degrees. And the hot leg temperature will go up about 4 degrees.

And this is basically what we targeted and we've optimized our turbine, our replacement high pressure turbine for this steam pressure for the EPU condition. Again, depending on our new generators, our new replacement generators operate. And they do seem to match up pretty well with the pre-EPU estimate there of 822 psia. They're pretty much right on that. So we probably won't be needing to make any adjustments in T_{avg} but if --

MEMBER WALLIS: What do you mean psia?

MR. FREDERICK: Pardon me?

MEMBER WALLIS: Did you adjust for atmospheric everyday? Don't you measure psig?

MR. FREDERICK: Yes. We actually measured 810 psig is what we're seeing out of the replacement generators.

Move on to the next slide it shows the Unit 2 target values. In Unit 2 we're actually intending to reduce T_{avg} a couple of degrees. And the intent here is to try and maintain the hot leg temperature at approximately where we are now, which is at 609. That will minimize any impacts on the materials.

MEMBER MAYNARD: Now Unit 2 is the one that still has the 600 --

MR. FREDERICK: Yes.

MEMBER MAYNARD: Is that the main reason you're trying to keep the --

MR. FREDERICK: That's correct.

MEMBER SIEBER: Unit 2 has 600? Okay.

MR. FREDERICK: And again, a T_{avg} results in a reduced steam pressure here. So when we replace our high pressure turbine in Unit 2, we'll be targeting a lower steam pressure for the optimum design in that turbine.

In the area of safety setpoints, we have made a couple of changes to reactor trip setpoints. Primarily these are the delta T trips, the overpressure and over temperature delta T trips.

We've reduced the primary setpoint for these trips. If you're familiar with the trips, that's the K_1 and K_4 terms.

We've also added some filters on the equations, the functional equations. I can pull up a slide. You're looking puzzled, so we'll pull it up here.

MEMBER WALLIS: I'm puzzled.

MR. FREDERICK: This is the actual equation that models this trip. And again, that's all done electronically.

The K_1 term for the OT delta T trip and the K_4 term for the OPR, the primary trip and then the rest of the terms there are basically lag and lead functions and also some adjustments based on actual temperature and pressure conditions.

MEMBER WALLIS: How long are these times typically that are in the --

MR. MURTAGH: This is Brian Murtagh.

The filtering is about 6 seconds for the T_{avg} and delta T filters. All the other time constraints are typically for the lead lag function would be 30 over 4. Tile 1 and tile 2 would be tile 130, tile 24.

MR. FREDERICK: Does that answer your question?

MEMBER WALLIS: Yes. I was just going to get an order of magnitude of the tiles to see what sort of times you're dealing with.

MR. FREDERICK: Right. The filters,

again, were added essentially to give us additional operating margin so we don't see inadvertent trips from temperature spikes and that type of thing.

MEMBER WALLIS: To wipe out the bouncing array?

MR. FREDERICK: The noise, right. Correct. And with the reduced trip setpoint and the additional filters we're not really losing any operating margins.

Some other --

DR. BANERJEE: Does this sort of take out some specific frequency component and above? When looking at this equation I can't tell anything. So what is the frequency cut off --

MR. FREDERICK: Brian?

MR. MURTAGH: Well, if you were to look at it in terms of a low pass filter --

DR. BANERJEE: Yes.

MR. MURTAGH: -- then the cut of frequency would be the inverse of one over 6 seconds, say.

DR. BANERJEE: One over 6 seconds?

MR. MURTAGH: Yes.

DR. BANERJEE: Why 6 seconds? Why not 10, why not 3?

MR. MURTAGH: Well, I believe probably as much as you increase the filtering, you're going to have to decrease the setpoints. Okay. So it's an optimization of how you want the circuit to function. You know, it's a trade off between that protects part of it --

MEMBER WALLIS: If it's too long, then you don't respond quickly enough.

MR. MURTAGH: Right.

MEMBER WALLIS: And if it's too short, you respond to every little transient.

MR. MURTAGH: And if it doesn't respond quickly enough, you'll have to reduce the set point.

DR. BANERJEE: So is this judgment call? Is it a judgment call or is it an optimization? Optimization assumes there's a function you're trying to maximize, right?

MR. MURTAGH: Yes. I believe the code for it is OptiMax code -- OptoX code used by Westinghouse.

DR. BANERJEE: What is it you're trying to optimize?

MR. DURKOSH: This is Don Durkosh.

What I wanted to point out was the time constants here. These were established many years ago at Westinghouse and they were optimized based on the plant design. And for the most part these constants have stayed pretty much the same and have been used by just about all Westinghouse plants.

As part of this project all they did was they looked at this and they tried to optimize. As Ken pointed out, what they did was they lowered the steady state trip value of small mount and by doing that they were able to add a small time delay so that if a particular noise event occurred, it wouldn't bring that channel into a partial trip condition. So it's just a small trade off as steady state versus a transient change.

DR. BANERJEE: So how small was this? What was small here?

MR. DURKOSH: Well, I don't have the numbers memorized, but I did talk to the Westinghouse and--

DR. BANERJEE: Rough terms.

MR. DURKOSH: Basically these values are representative of what other plants have. They are not out of line.

MEMBER KRESS: Don't you need some sort of measure of the normal oscillations to do this optimization?

DR. BANERJEE: What does that mean in delta T? I can't tell that with the ratio?

MR. DURKOSH: Well, let's take the first

bullet here.

DR. BANERJEE: Yes.

MR. DURKOSH: At steady state conditions for K_1, 1.259. What that means is if loop delta T got up to 25.9 percent above nominal, it would actuate. So we've lowered that value a little bit. We've reduced the steady state trip value from 25.9 percent to 24.2 percent at Unit 1. And we traded that margin off against just delaying the signal and the length of the signal that requires actuation.

DR. BANERJEE: By how much? It would be nice to have real numbers instead of percentages because I can't tell what they are looking at them. Whether there's a degree, 10 degrees, 5 degrees; what is the number?

MEMBER WALLIS: Well, I guess our interest would be --

MR. DURKOSH: The number for --

DR. BANERJEE: How many seconds, how much average --

MR. MURTAGH: The K_1 number means for your at nominal delta T that you have measured at 100 percent power. If you reach a 124 percent of that value, you will trip.

DR. BANERJEE: Right. But you know the

normal operating temperature --

MR. FREDERICK: The nominal delta T is about 60 degrees.

DR. BANERJEE: Sixty degrees?

MR. FREDERICK: Right.

DR. BANERJEE: So you've reduced that by how many degrees?

MR. FREDERICK: The trip?

MR. MURTAGH: The trip will be 124 percent of the nominal value.

MR. FREDERICK: Well, 2 percent of 60 is roughly one degree.

DR. BANERJEE: This is my head, I need a calculator.

MR. FREDERICK: It's roughly 1 degree delta.

DR. BANERJEE: Okay. One degree. And the time?

MR. FREDERICK: I'm not sure. Brian, do you know what the time change was? In addition to the filter, what does it --

MR. MURTAGH: Well, there's no direct correlation between filtering and --

MEMBER WALLIS: The only thing that matters to me really is the impact of these things on the plant.

DR. BANERJEE: Yes. So one degree change is a small change, but that has given you a big change in the time available?

MR. MURTAGH: Has that given you a big change?

DR. BANERJEE: How much?

MR. MURTAGH: The time delay is going to be built into the safety analysis where the function is no longer credited as an immediate trip. It would be assumed to be delayed in a safety analysis.

DR. BANERJEE: By how much?

MR. FREDERICK: If I understand what you're asking, we'll get that number for you.

DR. BANERJEE: You know, I just want to get a feel for does 1 degree change in this give you twice as much time or is it --

MR. FREDERICK: Yes, I understand.

DR. BANERJEE: -- five percent, or nothing?

MR. FREDERICK: We'll have to get back to you on that.

MEMBER SIEBER: Well, there's an inherent time delay anyway.

DR. BANERJEE: If it's small, it's

irrelevant. Yes.

MEMBER SIEBER: That's because of the instrument response.

DR. BANERJEE: Yes.

MEMBER MAYNARD: But it's still a trade off, but you're not approaching any limits anymore. You're trading off the point at which it trips or a time. It's still within that time. It can't exceed any of your safety analysis requirements or anything. So it's not changing a limit that you're going to get to.

MEMBER SIEBER: Right.

DR. BANERJEE: Anyway, appreciate having the time.

MEMBER WALLIS: And I think our main message should be it changes to what? What's the adverse consequence because we haven't said anything about the consequence here.

MR. FREDERICK: Right. Yes, the delta T trips are primarily DNBR protection trips --

MEMBER WALLIS: So the thing is by changing this, have you reduced the DNBR margin significantly? That's what really we should look at?

MR. FREDERICK: Yes.

MEMBER WALLIS: Maybe you could tell us--

MR. FREDERICK: Yes, well we'll talk about that in some detail later.

MEMBER WALLIS: We'll get to that, I presume.

MR. FREDERICK: Right. Right.

MEMBER WALLIS: You heard about how we probed the last applicant on this question?

MR. FREDERICK: Yes. Yes.

MEMBER WALLIS: Thank you.

MR. FREDERICK: Okay. Let me go back to the original slide here.

Other protection system changes. We've changed the low steam generator level trip for Unit 1, and that's associated with changes in the instrument span for that replacement generator. Has a larger, narrow range span.

Again, as we talked about before, we were eliminating the flux rate trip. And that, again, was a generic approved, not associated with EPU, but included.

The containment set point changes were associated with containment conversion. Those have already been implemented. We've raised the setpoint since we've increased the normal operating pressure.

And we also at that time, we revised the low level RWST recirc setpoint. And that was --

MEMBER WALLIS: You went from a reduced pressure containment to an atmospheric, is that what happened?

MR. FREDERICK: That's correct.

MEMBER WALLIS: Why did you do that? Maybe you've explained that already, but why?

MR. FREDERICK: Yes, we can talk about it later. But primarily the reason is --

MEMBER SIEBER: To make old guys breath easier, right?

MR. FREDERICK: That is a very key factor, yes. We have an aging workforce and wearing 40 pound biopacks in containment is certainly not very comfortable. So it does add a --

MEMBER WALLIS: An aging workforce is what--maybe we should pressurize this room.

DR. BANERJEE: Oxygenate.

MR. FREDERICK: Consideration of personnel safety and we also see some other benefits in the analysis from the increased pressure. And we'll talk about that later.

DR. BANERJEE: What is the RWST level low-low setpoint lowered? What is the implication of this?

MEMBER SIEBER: I'm sure safety injection is --

MR. FREDERICK: The setpoint is where transfer from injection mode to recirc mode. And by lowering that setpoint we end up with more water in the sump whenever we do that transfer so that increased the NPSH margin for primarily the low head safety injection pumps.

DR. BANERJEE: Do you have a problem with NPSH margin?

MR. FREDERICK: Yes, we're pretty close to the limit.

DR. BANERJEE: Is that why you're doing that?

MR. FREDERICK: That was one of the reasons, yes.

DR. BANERJEE: And the water is hotter because your containment is at a higher pressure now?

MR. FREDERICK: Yes. It is slightly higher. And we'll talk about some of that in the containment portion of the --

MEMBER SIEBER: Yes, that shouldn't be by much, though.

MR. FREDERICK: Yes.

Next slide, please.

We have changed some of the control system setpoints. Again, these were just setpoint changes, none of the control schemes were function changes in the plant.

Pressurizer level is something that's programmed to T_{avg} so that the maximum or the normal operating level is a function of what T_{avg} we're operating at. So raising T_{avg} a couple of degrees will increase pressurizer level by a couple of percent of full power.

MEMBER SIEBER: Well the controller will do that, but you program it to make it happen, right?

MR. FREDERICK: Yes. There is a little rescaling involved. But, yes.

MEMBER SIEBER: I take it you've analyzed the response of the pressurizer for various transients and accidents to show that it is still of adequate size?

MR. FREDERICK: Yes. We've analyzed for the full range of accidents and also margin to trip analyses.

MEMBER SIEBER: Okay.

MR. FREDERICK: The more normal occurrences. And we'll talk about it --

MEMBER SIEBER: And the change you're

making is not that great, so it shouldn't have a big impact on the pressurizer size.

MR. FREDERICK: Right. Right.

MEMBER SIEBER: Okay.

MR. FREDERICK: We're also changing some of the steam dump. This is essentially the turbine bypass system. The control setpoints there are optimized to operate for the EPU condition.

Steam generator level again for Unit 1 with the replacement generator, we have to increase the setpoint for normal water level. Essentially it stayed the same where we were before because of the increased span on the tape settings.

DR. BANERJEE: I didn't get that last point. Why did you have to increase the --

MR. FREDERICK: The replacement steam generators, they have a 212 inch span for the narrow range. The old ones had about 144 inch range. So to get to the same level now we're at 65 percent, which before we were at 44 percent. So it's just a change based on the span.

Next slide.

MEMBER SIEBER: These slides that have the little boxes like this one to the right, that's a backup slide?

MR. FREDERICK: That's correct.

MEMBER SIEBER: Are they in this book some place?

MR. FREDERICK: No, they're not. We do have copies available.

MEMBER SIEBER: I think we would need the copies of the slides that you show?

MR. CARUSO: I have those. I'll print them up for you. I have an electronic copy of this.

MEMBER SIEBER: Oh, okay.

DR. BANERJEE: If you have an electronic copy of all this --

MEMBER SIEBER: Why don't you just give us the electronic copy and --

DR. BANERJEE: So then we just may get the electronic copy from you rather than this.

MR. CARUSO: Sure.

MR. FREDERICK: This slide basically outlines the methodologies that we used for the safety analysis. And it also shows what the current methodologies were. So for large break LOCA we are changing from the Westinghouse BASH methodology, which was Appendix K method, to the BE LOCA methodology, which uses the COBRA/TRAC code.

And as we mentioned previously, this is

the original BE LOCA methodology approved in 1996 when we started this program, ASTRUM, which is what Ginna used, wasn't approved at that time. So we're not using that.

DR. BANERJEE: Do you do these calculations yourself or somebody else does it?

MR. FREDERICK: Westinghouse has performed these calculations for us.

DR. BANERJEE: I see.

MEMBER SIEBER: You have access to their codes, though, right?

MR. FREDERICK: I have access to LOFTRAN, but not the LOCA codes. Just the non-LOCA.

DR. BANERJEE: So you sort of contract them to do this work?

MR. FREDERICK: That's correct.

DR. BANERJEE: And how much audit capability do you have of what's going on there?

MR. FREDERICK: We have reviewed all of the calculations that were done for the uprate. In other words --

DR. BANERJEE: You don't have a copy of the code to test out or anything like that?

MR. FREDERICK: Well, again, in the case of non-LOCA I do have a copy of the LOFTRAN code which

I do run. I don't have a copy of NOTRUMP or COBRA/TRAC. Our review is basically limited to making sure that they use the inputs that we specify and making sure the output looks reasonable.

As I mentioned, large break we have changed to BE LOCA. The small break still uses NOTRUMP, which is the Westinghouse small break approved methodology.

MEMBER WALLIS: Now you've changed to best estimate method. Did you try to use BASH on the power uprate?

MR. FREDERICK: No, we did not.

MEMBER WALLIS: Because I was wondering if you would be over the limit if you used it? Did you use BE LOCA because you have to because otherwise you'd--

MR. FREDERICK: It was a decision that we made to regain some margin which would help us out with the --

MEMBER WALLIS: It's so conservative. It looks like it would drive you over the limit if you gain power too much.

MR. TESTA: Ken, if I can input here. I'm Mike Testa, I'm the Project Manager at Beaver Valley.

When we first set out on this project with the extended power uprate, you know, we were going to do an extensive reanalysis. And part of that is we wanted to bring the design up to the later design codes. So that was an opportunity for us. We knew we had to redo the LOCA analysis and we choose to go to the BE LOCA methodology.

MEMBER WALLIS: And my question really was if you'd used BASH, because I'd like to compare the new with the old when you give us, say, 2190 degrees or something.

MR. TESTA: Yes. We did not run--

MEMBER WALLIS: And maybe the temperature actually goes down with the new prediction method because it's because of the method, rather than the physics.

MR. FREDERICK: Yes. But we did not run that.

MEMBER WALLIS: But I think we'll get into that later, perhaps.

DR. BANERJEE: Was there industry experience with something equivalent to BASH that suggested you should do BE LOCA?

MR. FREDERICK: Certainly the BE LOCA was known to provide better results just because of the methodology --

DR. BANERJEE: There were lower --

MEMBER SIEBER: That's correct. Yes.

DR. BANERJEE: Lower results? Better we don't know for sure.

MEMBER WALLIS: From the point of view of safety, better is higher.

DR. BANERJEE: Better results?

MEMBER SIEBER: Lower results.

MEMBER WALLIS: Because then you could back off.

MEMBER SIEBER: Well, there is a typical for BE LOCA in an SER which would -- I don't know whether that --

MR. FREDERICK: This version of BE LOCA was actually approved in 1996 and a lot of other plants have been using it.

DR. BANERJEE: Yes, but --

MEMBER SIEBER: You may want to look at that topical in the SER to determine what the equivalence, if any, there is. Because there probably isn't much of an equivalence because one uses an extreme boundaries of everything whereas BE LOCA is best estimate with uncertainty. Get a different answer.

MR. CARUSO: I believe the Committee has

written a letter on this method.

MEMBER SIEBER: I suspect they have.

MEMBER WALLIS: Well, it came up with the last applicant that they had used the Appendix K method. I think they went over 2200 degrees. BE LOCA put them way below. So it makes a big difference.

MEMBER SIEBER: Yes.

DR. BANERJEE: But going back, I just want to be -- have any of these other uprates that were listed which are somewhat similar to these used something equivalent to BASH in doing that, do you know?

MR. FREDERICK: I don't know. I'm sure that some of the older uprates would have used BASH because that was what the licensed code was at that time.

Matt, do you have any --

MR. CERRONE: Yes. Hi. My name is Matt Cerrone with Westinghouse.

All recent uprates are all done with best estimate methods for the large break accident.

DR. BANERJEE: When was the last one done with BASH?

MR. CERRONE: I don't know.

DR. BANERJEE: Was there one done with

BASH?

MR. CERRONE: I can't imagine. I mean, my experience would have it that -- basically all my experience with Westinghouse was whenever we would move to a new product or especially with uprates, the best estimate technology using COBRA/TRAC is the methodology of choice because it is capable of modeling the phenomena that's expected out of these codes for large break accidents these days.

DR. BANERJEE: Now just to follow this. The BASH number for the unuprated plant were acceptable, I take it? Now, this 10 percent increase must then give some problem with BASH, otherwise why would people go running to the best estimate.

MR. FREDERICK: I do have a slide later that shows the BASH results with current power level.

MEMBER WALLIS: I take it we're going to get into each of these in detail later on?

MR. FREDERICK: That's correct.

MEMBER WALLIS: Okay.

MEMBER KRESS: When you do the large break LOCA did you take advantage of the new break size that NRC is flirting with?

MR. FREDERICK: No, we did not.

MEMBER KRESS: You used the actual large

double winded --

MR. FREDERICK: Yes, double winded rupture.

MEMBER SIEBER: When you did the calculations for the alternate source term in your containment parameters, you used the latest DKE curve? Does BELOCA use the same DKE curve or the earlier versions that the Appendix K used?

MR. FREDERICK: BE LOCA methodology uses the 79 curve with 2 sigma, not the 71.

MEMBER SIEBER: Okay. That's the later?

MR. FREDERICK: That's correct.

For non-LOCA events we've changed the DNBR calculation methodology from THINC to VIPRE. LOFTRAN is still used for the thermal hydraulics.

In the containment area again, as part of the containment conversion submittal which was recently approved, we have gone to MAAP-DBA. Previously we used a Stone & Webster code named LOCTIC, called LOCTIC.

And again, in dose assessment area we have implemented -- we have gone to a full implementation of the alternative source term and we're also using ARCON 96 now for on-site --calculations.

Essentially this is just a list of the

non-LOCA events that we've analyzed or evaluated. These are categorized by the Standard Review Plan categories. I'm not going to read them all. You can look at them there. The next couple of slides here. In total there's 18 events in the non-LOCA area that were again looked at for EPU and these have new analyses associated with them.

MEMBER WALLIS:

You're going to give us a table of results somewhere?

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

For condition II events which comprises a majority of the non-LOCA events, the acceptance criteria are meet the DNBR limits, heat generate rate has to remain within the acceptable limits. The RCS and the secondary pressures need to stable to 110 percent of the design. And the event cannot progress to a more series level 3 or level 4 event.

DR. BANERJEE: Does this also apply for steam line breaks?

MR. FREDERICK: Yes. Well, steam line break, as we'll see, is actually a condition IV event. But when we analyze it we use condition II criteria. So it does apply, yes.

MEMBER WALLIS: Now you've seen these

slides before. Is something wrong with the screen here? Is that why it doesn't look good?

DR. BANERJEE: Yes.

MEMBER WALLIS: Why did the NRC, we designed this room and give us a far worse screen than we had before.

MEMBER KRESS: That's a good question.

MEMBER WALLIS: I think we should put that on the record.

CHAIRMAN DENNING: I don't think we're going to demand that you answer that.

MEMBER WALLIS: Well, I just want to make sure it's not just me. I mean, when you get --

MEMBER KRESS: It's not just you. Rest your eyes.

MEMBER WALLIS: It's a good slide.

MR. FREDERICK: Next slide.

The first acceptance criteria we're going to talk about is the DNBR limits. As we mentioned earlier, DNBR is calculated using approved correlations. For Beaver Valley we use three correlations, WRB-1. WRB-2M and W-3. And the application of these is essentially controlled by what conditions they're approved for and also what the operating conditions are for the analysis. And we'll get into some examples later.

Primarily WRB-2M is used because that is specifically for the RFA fuel, which we use, and for the high temperature regions of the fuel with the mixing vanes.

Something else that's used here is called revised design thermal design procedure. And that is a methodology, again an NRC approved method which takes the uncertainties on power, flow, temperature and pressure and combines those into essentially a penalty that's applied to the DNBR limits. And we'll see that again on the next slide.

One thing to mention here is that at Beaver Valley, primarily because of the change to WRB-2M and the RFA fuel we actually have 21 percent margin between what we use as a safety analysis limit and the actual design limits for the fuel. And essentially that margin is retained to give the core designer some flexibility in the reload process so that if an issue comes up or a penalty that needs to be applied and they have the flexibility to do that without having to go back and redo all the safety analysis.

So if you look at the next slide, this kind of gives you a picture of how the limits are developed. On the left is the DNBR ratio. And on the right is the corresponding limit. So 1.0 obviously is critical heat flux.

The correlation limit is actually a tech spec value and it reflects the uncertainty in the correlation that corresponds to the 95/95 confidence level.

From there we go up to 1.22, which is what we get when we add in the uncertainties associated with the initial conditions in the core for power flow, pressure and temperature.

And finally, the 1.55 is what we're using as the safety analysis limit. So in between the 1.22 and the 1.55 essentially is margin which is retained by the thermal hydraulic people in the --

MEMBER WALLIS: Now the previous applicant used 1.38.

MR. FREDERICK: That's correct.

MEMBER WALLIS: So it seems there's a lot of flexibility in what you choose to use.

MR. FREDERICK: Yes. That limit is something that is somewhat negotiated between the fuel designers and the safety analysis people within Westinghouse in this case.

MEMBER WALLIS: So should we give you high marks for having a high DNBR? More safety, presumably.

MR. FREDERICK: Yes. The limit is set high primarily because in the past we had transition core penalties which have since gone away since we're into all RFA fuel at this point. But we haven't changed the limit.

MEMBER WALLIS: I wasn't here earlier. Are you changing the fuel when you do the uprate?

MR. FREDERICK: No.

MEMBER WALLIS: Not at all?

DR. BANERJEE: But it's all RFA fuel?

MEMBER SIEBER: I guess the more important question when you talk about margins is do you have somebody in your organization who is the keeper of margins? For example, you know there are things you can do when you refuel the reactor if you don't put in the flow limiting devices, that changes the core flow significantly and trades margin around. And if you don't have a single person who is watching what the condition of the core and all the modifications to the plant and changes in operating procedures, you may be giving up margin that you would rather have someplace else, or maybe two people taking a bite out of the same margin unbeknownst to one another.

MR. FREDERICK: Right.

MEMBER SIEBER: Do you have somebody that does that?

MR. FREDERICK: Well, primarily that's me, yes. We're very aware --

MEMBER SIEBER: Do you do a good job of that?

MR. FREDERICK: I think so.

MEMBER SIEBER: You want to write that down?

MR. FREDERICK: I'm very aware of where our margins lie, particularly in terms of accident analysis, results, PCTs for LOCA events and DNBR margins. Those values are associated are actually published every time we do a reload safety analysis. So we understand what the margins are and we provide the majority of the inputs for the reload evaluation. So there's margins that have to move around or to trade off operating margins. And we're part of that process and we're aware of it.

MEMBER SIEBER: And so are you on the on-site safety committee?

MR. FREDERICK: No, I'm not.

MEMBER SIEBER: But you are the keeper of the margin.

MR. FREDERICK: Our on-site safety

committee--

MEMBER SIEBER: Do you have somebody in your organization who is on that committee?

MR. FREDERICK: We do.

MEMBER SIEBER: Okay. Since you're the keeper of the margin --

MR. FREDERICK: He sits right across from me, so --

MEMBER SIEBER: Okay.

MR. MANOLERAS: Yes, Jack. And this Mark Manoleras.

We do sit on the Core Reload Safety Process. We have a sign-off on that, a design engineering manager and Ken. We have a sign-off on that Core Reload Safety Process. We have a direct input to that process.

MEMBER SIEBER: Okay. Yes, what I concern myself with is sometimes there are subtle little changes in the operation and maintenance of the plant that can change these margins.

MR. BURGER: Yes. This A.R. Burger again.

What we do in the core design process, we have a reload project team. Ken will be part of that. We have operations training, chemistry, design engineering. What we'll do is look at that on each reload and decide: (a) what changes are being made in the plant with other items that are out there and then we'll determine where we can put our DNB margin based on what's going on in each reload.

MEMBER SIEBER: And the refueling supervisor is part of that?

MR. BURGER: Yes.

MEMBER SIEBER: Okay.

MR. FREDERICK: Can I move on? Okay.

This is a table that shows the results for events which primarily are looked at for DNBR as one of their limits. And as you can see here, some of the events use correlations other than WRB-2M. For example, the first one is a rod withdrawal from subcritical so the correlation essentially does not apply in that power range, so we used W-3 and WRB-1 which are applicable at that condition.

Also for the hot zero power steamline rupture we used W-3 for that. For similar reasons it's not a full power event.

CHAIRMAN DENNING: And the reason on the first one, the RCCA bank withdrawal was acceptable is you believe the 1.65 on the W-3 more than the WRB-1 or what's --

MR. FREDERICK: Actually, Chun, maybe you can explain this. But both of those are used in various regions of the --

MR. FU: This is Chun Fu, Westinghouse.

The used of WRB-1 correlation is because for this rod withdrawal from subcritical the similar condition is out of the applicable range of WRB-2M correlation. But we did confirm, you know, that DNB criteria is met with WRB-1 correlation.

MR. FREDERICK: I think he was asking why we used both W-3 and WRB-1.

MR. FU: Both W-3 correlation, you know, WRB-1, WRB-2M correlation is applicable only for the mixing in grid spans. So we still use W-3 for the first span just from the inlet to the first mixing grid. So W-3 is always correlation.

MR. FREDERICK: So it's the position on the fuel rod where --

MEMBER WALLIS: So this doesn't indicate two different results from two correlations for the same place?

MR. FREDERICK: That's correct.

MEMBER WALLIS: It's different places, right?

MR. FREDERICK: Yes.

As you can see here the limiting case in terms of DNBR margin is the rod withdrawal of power event. And we're going to talk about that in some more detail here in a little bit.

CHAIRMAN DENNING: How does the positive moderator coefficient impact some of these as far as if you had zero moderator coefficient versus the small positive? Is it measurable in terms of the DNBR as to what result you get?

MR. FREDERICK: Chun, could you answer that?

MR. FU: I don't know --

MR. McHUGH: This is Chris McHugh from Westinghouse.

The positive moderator temperature coefficient does show up in the analysis if you have a heat up event and you analyze the zero MTC versus a small positive, you will see a difference in the results.

To correlate that to a change in DNBR would be a function of which event you're talking about.

CHAIRMAN DENNING: But for example in this bank withdrawal of power, is that --

MR. McHUGH: In the bank withdrawal at power --

MEMBER SIEBER: It would be part of it.

MR. McHUGH: It would be a small penalty, yes.

MR. FREDERICK: As I mentioned earlier, the steamline ruptures are actually condition IV events but we do analyze them to the DNBR --

MEMBER WALLIS: Now there seem to be fewer items in this table than there were on pages 33536?

MR. FREDERICK: Yes. Again, these are primarily the events which challenge the DNBR limits.

MEMBER WALLIS: We have to assume that the other ones are milder?

MR. FREDERICK: Either they're not analyzed for DNBR because of the nature of the event would not cause DNBR to decrease or they're just not anywhere near limiting.

MEMBER WALLIS: But how do you evaluate something like uncontrolled boron dilution? Are you going to tell us that or --

MR. FREDERICK: Chris, can you answer that?

MR. McHUGH: We do an uncontrolled boron dilution calculation. We take the active mixing volume, the initial and critical boron concentrations and calculate a time that it takes to dilute it and lose shutdown --

MEMBER WALLIS: You say that the operators have enough time to take action?

MR. McHUGH: Right. We conclude that they have in excess of 15 minutes.

MEMBER WALLIS: You don't calculate any kind of adverse effect. You just assume it's avoided?

MR. McHUGH: Right.

MR. FREDERICK: Next slide.

CHAIRMAN DENNING: One more thing, and that is pre EPU what did the RCCA bank withdrawal look like.

MR. FREDERICK: I have that on that slide when we talk about that event.

CHAIRMAN DENNING: Okay.

MR. FREDERICK: One of the other key criteria for the condition II events in the RCS or primary and secondary pressure. This shows the primary pressure limits in terms of how they correspond to the ASME service level stress limits. So, for example, starting at the bottom there at 2250 is our normal operating pressure. The design pressure system is 2485 psig. For service level B, which is used for condition II events, the ASME stress limit is 1.1 times the allowable stress. Conservably, that's just taken to mean a 110 percent of the design pressure even though if you looked at every component, you may be able to exceed 110 percent of design.

Similarly for level C we use a conservative criteria for locked rotor of 120 percent. Locked rotor is a condition IV event.

For ATWS the approach taken there was to actually go and look at all the components. And the limit arrived at in that manner was 3200 psig. So that is the limits applied to ATWS events.

MEMBER WALLIS: Again, these pressures aren't all to be engaged because that's what the vessel fields, isn't it?

MR. FREDERICK: That's correct.

MEMBER WALLIS: The vessel doesn't know anything about absolute pressure.

MR. FREDERICK: The analyses --

MEMBER WALLIS: If you put it in a different containment --

MEMBER SIEBER: Do you happen to know the number where you would actually get a failure of the vessel?

DR. BANERJEE: You could have a vacuum.

MEMBER WALLIS: Never been tested, has it?

MR. FREDERICK: Yes. I don't know that

number, Jack. 3200 was based on --

MEMBER SIEBER: It's like three times 25, right?

MR. FREDERICK: Yes.

MEMBER SIEBER: Twenty-five hundred?

MEMBER WALLIS: Seven thousand psi or something like that?

MEMBER SIEBER: Yes, something like that.

MEMBER WALLIS: Because it stretches bolts before that.

MEMBER SIEBER: Well, I would be heading out of town if it was going up there.

MR. FREDERICK: This table shows the results from the events which challenge the over pressure limits. As you can see here, loss of load is a limiting event for condition II events. At 2747 for Unit 1 --

MEMBER WALLIS: That's pretty close, isn't it? That's pretty close.

MR. FREDERICK: Yes. We're going to talk about that event in more detail soon.

MEMBER WALLIS: No uncertainty? This is just one spot calculation, best estimate?

MR. FREDERICK: No. This is a very conservative analysis, and that's what we're going to demonstrate.

MEMBER WALLIS: That's why it's okay.

MR. FREDERICK: This also shows locked rotor, which again is below the 120 percent limit and the ATWS analyses for both units.

DR. BANERJEE: What were these limits before the uprate?

MR. FREDERICK: The limits have not changed.

MEMBER WALLIS: No, but what were your values?

DR. BANERJEE: I mean the peak primary pressure values?

MR. FREDERICK: I do have that for the limiting case here. The loss of load I don't have that value.

MEMBER WALLIS: You sat in on the last presentation?

MR. FREDERICK: Yes.

MEMBER WALLIS: Where I asked for a table comparing before and after?

MR. FREDERICK: Again, we do have that for all the limiting cases that we're talking about.

MEMBER WALLIS: It gives us some perspective on what's going on.

MR. FREDERICK: Yes.

DR. BANERJEE: Loss of load may be ATWS and locked rotor, only of significance of right there, the rest of them --

MEMBER SIEBER: ATWS is a service level D event.

DR. BANERJEE: Yes.

MEMBER SIEBER: And loss of load is a service level B event

MR. FREDERICK: That's correct.

MEMBER SIEBER: They're different limits, right?

DR. BANERJEE: Yes, they have the same pressure limits as well, right?

MEMBER SIEBER: Right.

MR. FREDERICK: Right.

DR. BANERJEE: But it would be interesting to see what it was before.

MR. FREDERICK: What the results were before?

DR. BANERJEE: Yes, compared to now. I mean before and after.

MR. FREDERICK: Okay. I think we have those. Do we have those, Chris, before?

MEMBER WALLIS: Yes. If they're not ready this morning, you could flash them up this afternoon.

MR. McHUGH: Right.

MR. FREDERICK: Yes.

MEMBER WALLIS: Now what limits your power uprate? Is it secondary side or is it some of the safety limits? Why don't you go to higher power uprate? Is it safety limits that limit you?

MR. TESTA: This is Mike Testa again, Beaver Valley.

When we first started the project and as we showed in the beginning presentation, we looked at where the industry was operating the Westinghouse 3 loop PWRs. And we basically are aligned with them. So when we looked at the power level, we went to 2900 NSSS power, core power and that aligned us with the other --

MEMBER WALLIS: So you looked at similar plants and what they can do?

MR. TESTA: And then of course then we looked at the modifications that we needed to perform on the balance of plant side to achieve that.

MEMBER SIEBER: How much it --

MEMBER WALLIS: But conceivably if you've gone to higher power, you might get a 2750 something loss of load.

CHAIRMAN DENNING: Well, I have a relevant question to that, and that is what -- it's not chance that the pressure has come to 2747/2746 right there. Have you modified something like a setpoint or something like that that brings you there? What is it that --

MR. FREDERICK: Yes. One of the key inputs to this analysis is the tech spec limit on the tolerance for the setpoint for the safety valves. And in the case of Unit 1 we increased that from one percent to a three percent tolerance. And Unit 2 increased from 1 to 1.6. So it does drive the results much closer to the limit. And we'll talk about that a little later.

MEMBER WALLIS: You will talk about that?

MR. SENA: And this is Pete Sena, Director of Engineer.

Again, Dr. Wallis, our goal here was to go through the non-LOCA transients, take out the two most limiting transients and then go into great detail so you can see what margins do remain. That's what's Ken is going to get to next.

MEMBER WALLIS: Thank you. That makes sense. That's sort of thing we asked for last time. So thank you.

MR. FREDERICK: This slide looks at some of the other more unique criteria. Pressurizer filling is a concern essentially for progression. If we fill the pressurizer, then the chances are we could evolve into a small break LOCA which we don't want to happen. So we look at that for some of the analysis which challenged the overfill.

As you can see there, in the limiting case the spurious SI, we do actually fill the pressurizer and we'll have a more detailed discussion on that event and what we've looked at to convince ourselves that that's okay.

Margin to hot leg saturation or no boiling in the hot leg is a criteria that's applied for feedline break, which again is a condition IV event. So this is a conservative criteria for that event. And as you can see there, we have a margin to the hot leg boiling.

MEMBER WALLIS: Loss of control you're worried about, not popping something in the pressurizer?

MR. FREDERICK: I'm sorry?

MEMBER WALLIS: The relief valve opens on the pressurizer and then it fills up?

MR. FREDERICK: Yes. The concern there is if you're passing water through a safety valve it's not really designed for --

MEMBER WALLIS: All right. But it can pass with this water?

MR. FREDERICK: Yes.

MEMBER WALLIS: Right. But you lose control, that's what you're worried about. You lose pressure control?

MR. FREDERICK: Well, our concern would be that the valve might stick open --

MEMBER WALLIS: It does happen.

MR. FREDERICK: -- which would reduce pressure, yes. Yes.

MEMBER SIEBER: You have some other problems, too. You have this huge water slug going down the discharge line to the --

MR. FREDERICK: Yes, it would also challenge the --

MEMBER SIEBER: -- to the PRT, which is not a good thing.

MEMBER MAYNARD: You have separate power operated type relief valves and code safeties?

MR. FREDERICK: Yes, we have power operated relief valves as well as code safeties.

MEMBER MAYNARD: So the idea would be that those would open up, use those before the code safeties lifted, primarily?

MR. FREDERICK: That's correct. Yes.

MEMBER MAYNARD: Yes.

MR. FREDERICK: The last even there shown is the rod ejection where fuel stored energy limit the acceptance criteria. And as shown there, we meet that limit.

Next slide, please.

Again, this is a detailed discussion on the loss of load event. Basically provide a flavor for the level of conservatism --

MEMBER WALLIS: That BTU, what is that in calories per gram.

CHAIRMAN DENNING: Calories per gram?

MR. FREDERICK: Pardon me?

MEMBER WALLIS: Usually it calories per gram that we see. What is it?

CHAIRMAN DENNING: BTU per pound on max fuel stored energy. Do you know what that is conversion into calories per gram.

MR. FREDERICK: 260 or so.

MEMBER WALLIS: Or less?

MR. FREDERICK: Chris, if you want to look it up, it's in the licensing report on that computer there, I believe.

MEMBER WALLIS: Okay. We can do that.

CHAIRMAN DENNING: We can probably handle this conversion, but given half an hour.

DR. BANERJEE: And more oxygen.

MR. FREDERICK: Again, we're going to talk about loss of load transients in detail here. And the purpose is to give you an idea of the level of conservatism that these analyses are done to.

And this event produces the highest primary and secondary pressure of the condition II events. And the results from either a loss of load off the generator or a turbine trip that is caused by other inputs.

The reactor protection for this event, we have essentially five trips there that provide protection. Two aren't credited; the high water level trip and the pressurizer. That's just a conservatism in the analysis. And the reactor trip on turbine trip which is essentially the most direct trip for this event, that's not credited because that is not considered a qualified trip since it comes out of the turbine building, which is a non-seismic building.

We do actually run two cases for this loss of load, one to look at DNBR and one to look at the pressure. We're not going to talk about the DNBR case here. It's not close to being limiting.

In the analysis we, of course, bias all the input initial condition parameters to give us the worst results. Initial pressurizer pressure and level and the RCS power flow and temperatures; these are all biased in the actual run as opposed to done separately as we do for DNBR cases.

Also, we bias the reactivity feedback and we use manual rod control for this analysis.

CHAIRMAN DENNING: These are all realistic conditions, but it's just that you happened to pick them all in combination in their worst --

MR. FREDERICK: That's correct. Their initial control system setting, for example, pressurizer level at 53 percent, 7 percent is added on to that for uncertainty. So that's our initial condition for this analysis.

We don't take any credit for any of the control systems. Now essentially there's four control system that would come into play here. You know, condenser steam dumps. We also have atmospheric steam dumps on the secondary side. On the primary side we have pressurizer pressure control through the spray. And we also have power operator relief valves which would normally open up to 100 pounds below the code safeties.

For the code safety modeling we do use the maximum setpoint allowed by the tech spec. In the case of, for example, Unit 1 that is the setpoint plus 3 percent, which is our allowed tolerance or that changes part of the EPU package.

Also in the valve modeling there's delays model in the opening and that accounts for the time that it takes to purge the water out of the loop seal. In some cases, for example Unit 1 there's an opening time associated with the valve. It's a target rock valve. And there's also an additional shift put on the setpoint based on the loop seal being present on Unit 2.

The actual total impact of these changes represents about a 200 pound increase above what they would normally lift if we didn't include all these conservatism.

Next slide.

This just gives you a very rough estimate of the timing of the event. Essentially there's a delay between the initial event and when the actual trip begins of .5 seconds, which is very conservative and then there's an additional two seconds before the rods drop. And when the safety valves open is when we get peak pressure, and that occurs at 8 seconds.

And this plot basically just shows you the pressure transient. Again, we're seeing from the initial condition up to the peak it's about a 500 pound increase in pressure. And again, at 8 seconds when the valve opened, the pressure drops.

DR. BANERJEE: What code was used, just for my own?

MR. FREDERICK: LOFTRAN.

MEMBER WALLIS: Extraordinary accurate code, as you can see.

DR. BANERJEE: Huh?

MEMBER WALLIS: Extraordinary accurate code.

DR. BANERJEE: Right. Right. A significant figure.

MR. FREDERICK: This slide shows you the pre-EPU results. For Unit 1 that's a good comparison because the same safety valve tolerance was used for both cases, the 3 percent. So you see about a 15 pound increase in the peak pressure associated with EPU.

On Unit 2 we actually lowered the tolerance so actually you see the numbers dropping there a pound or so.

If we do a more realistic analysis, and we have, which credits control systems, we actually see a peak pressure much lower of about 2340 absolute. And at that pressure we don't actually even lift any of the safety valves on either side, primary or secondary, or the pore for that matter.

If you go to the backup slide, and this is a plot of that particular analysis both for pre-EPU and EPU. And essentially they look identical. There was no real impact of EPU in terms of the peak pressure that we see in this analysis.

DR. BANERJEE: Well, why is that? What's the physics?

MR. FREDERICK: Essentially the control systems --

DR. BANERJEE: Safety valves are the same, right?

MR. FREDERICK: Yes. And you're not even opening safety valves here. So it's just a matter of the control system acting the same and giving you the same response out of the system.

DR. BANERJEE: But what does the control system do here?

MR. FREDERICK: The control system opens up the turbine bypass, the condenser steam dump system. And that keeps the primary system from heating much, I mean as much as you would normally see. And also --

DR. BANERJEE: Does it open the bypass earlier or something just to shave the peak off? What is happening? I'm trying to understand why the two are so close to each other in spite of the fact that you have 10 percent more power?

MR. FREDERICK: Right.

DR. BANERJEE: So what's the physics?

MR. FREDERICK: Yes. Well, the power doesn't really enter into it much at this point. Yes, it does cause a general heat up and so --

DR. BANERJEE: And that causes --

MEMBER SIEBER: That's small.

DR. BANERJEE: -- total pressure to peak?

MR. FREDERICK: Well, after the reactor trip and then once the valves open, then it turns around all these --

DR. BANERJEE: Do the valves open earlier in the --

MR. SENA: Again, this is Pete Sena, Director of Engineering.

I think the difference between the two analysis is that the original analysis takes no credit for any control systems so the steam dump systems do not operate at all. And in the realistic analysis we've done here we are taking credit for the operation of those systems.

DR. BANERJEE: So the pre-EPU doesn't take credit for the --

MR. FREDERICK: Pete, he's asking --

DR. BANERJEE: All right. There has to be a good reason?

MR. SENA: Well, the pre-EPU and the post-EPU analysis use the same --

DR. BANERJEE: It's done differently?

MR. SENA: No, no. They use the same modeling. Why don't you go back, Ken, for the pre and post-EPU

DR. BANERJEE: Then the question is why does it?

MEMBER WALLIS: I think because it's controlled.

CHAIRMAN DENNING: It's controlled.

MEMBER WALLIS: It's because it's controlled. It's the same.

DR. BANERJEE: Something opens earlier, right?

CHAIRMAN DENNING: Or bigger or more.

DR. BANERJEE: Controlled means they have to control the flow on a valve or something.

MEMBER WALLIS: It might open more, the control.

MEMBER SIEBER: It doesn't open more. I think --

DR. BANERJEE: It might open earlier.

MEMBER SIEBER: -- the differences between these two curves are so subtle that you really can't pick them out.

MR. FREDERICK: Yes, I would say that they are not exactly the same, but on here they look pretty close.

MEMBER WALLIS: Because they look exactly the same.

MR. FREDERICK: And, again, we haven't changed the control system so we'd expect it to operate.

DR. BANERJEE: Right. So what are the control events here? Like what's happening?

MR. FREDERICK: You have the loss of load times zero.

DR. BANERJEE: Right. And then there's some trip?

MR. FREDERICK: And the reactor trips, in this case on turbine trip but there's a 2 second delay model.

DR. BANERJEE: But both of them trip at the same time?

MEMBER SIEBER: No.

DR. BANERJEE: Why not?

MR. FREDERICK: Well, the condenser steam dumps this and responds to the trip signal. And also it's based off of a delta T. Essential it looks at T_{avg} and where T_{avg} should be post-trip, T_{ref} we call it. And that delta drives the valve. So that program in the system isn't changing, so it's essentially maintaining the RCS conditions in a very similar manner so you see a very similar result here.

MEMBER SIEBER: But the heat up is slightly faster so the system operates slightly quicker?

MR. FREDERICK: Yes. I mean it's a proportional --

MEMBER SIEBER: I mean you could pick it out here.

MR. FREDERICK: -- band. So if the system demands more, the values will open faster and more.

DR. BANERJEE: I know what you're saying probably makes some sense, but what I'm really trying to understand is when you show the curve, like this curve here, this curve is the result of a very complex set of -- relatively complex set of control actions.

Now between the pre-EPU and the post --

MR. FREDERICK: That curve does not actually use any of the control systems.

DR. BANERJEE: Okay. Take one which does. Let's say --

MR. FREDERICK: This one does.

DR. BANERJEE: Yes, this one. So that there are several control actions taking place. And the fact that the two curves look so similar is because there could be subtle differences. But the fact they look so similar is due to control actions taking place at different times in the two.

MEMBER SIEBER: Slightly different times.

MR. FREDERICK: The valves could be opening faster because that's what they're programmed to do.

DR. BANERJEE: Yes.

MR. FREDERICK: They look at an error signal.

DR. BANERJEE: Well, whatever it is.

MR. FREDERICK: And if the error signal is higher, than the values will open faster and further.

MEMBER SIEBER: And once they're open, they're the same in the pattern.

DR. BANERJEE: Ten percent more power is produced in the other, right?

MR. FREDERICK: That's correct.

DR. BANERJEE: So it has to go somewhere?

MR. FREDERICK: That's correct.

MR. FREDERICK: So something must open faster?

MEMBER SIEBER: Yes.

DR. BANERJEE: There's no other way.

MR. FREDERICK: Yes.

DR. BANERJEE: Right. Okay. So that's, I guess, what doesn't come out clear.

MEMBER WALLIS: That's what turns things around?

DR. BANERJEE: Yes. So what doesn't come across is what are the actions which are turning things around here? What's happening? So in one case things are happening faster; that's why it's happening.

MR. FREDERICK: Yes. The actions that are occurring, again, the control system is trying to drive T_{avg} down to the no load value, post-trip.

DR. BANERJEE: Right.

MR. FREDERICK: And the system responds based on the delta. You know, where T_{avg} is versus where I want it to be. So if in the case of EPU that delta is higher initially, then the valves will open faster and further so that you would see the same type of response --

MEMBER WALLIS: The system is actually programmed to produce a curve like this?

MR. FREDERICK: That's correct.

MEMBER WALLIS: By control.

MR. FREDERICK: Yes.

MEMBER WALLIS: That's why the two curves are the same.

MR. FREDERICK: Yes.

DR. BANERJEE: So what would be sort of valuable to know is how much more rapidly do these control actions have to occur in the second case. The curves look the same but the control actions are occurring faster or something is happening, otherwise they wouldn't.

MR. FREDERICK: Right. Yes. I'd say it's a very small difference. This whole peak occurs within 8 second.

DR. BANERJEE: One second makes a difference, right, and 8 seconds --

MEMBER SIEBER: Yes, but it's 50 seconds just for that first --

MEMBER WALLIS: Depressurization.

MEMBER SIEBER: -- pressure peak and drop. So that's a long time compared to the response time of the control system itself, which is on the order of 6 to 10 seconds.

CHAIRMAN DENNING: Is pressurizer spray having any impact here as well? I mean we've focused on kind of the relief, but is it -- I know that you don't credit it in the other analysis, but is that one of the control functions that's impacting the similarities here?

MR. FREDERICK: I'm not sure. Chris, can you answer that

CHAIRMAN DENNING: Okay. I think we can on.

MR. FREDERICK: Okay.

MEMBER SIEBER: I think the big thing is a lot of heat removal through the turbine bypass valves.

DR. BANERJEE: Right.

MEMBER SIEBER: That's the big --

DR. BANERJEE: That has to open a bit faster?

MEMBER SIEBER: Yes. Maybe a couple of seconds.

DR. BANERJEE: Yes. I wanted to know how much.

MEMBER SIEBER: Yes.

DR. BANERJEE: In 8 seconds? Is it 6 seconds versus 8 seconds?

MEMBER SIEBER: It's hard to pick off that graph.

DR. BANERJEE: Right.

MEMBER MAYNARD: Well, the rate is going to depend on how much a discrepancy between --

MEMBER SIEBER: How big the delta is, yes.

MR. FREDERICK: Actually, just a couple of weeks ago we had a loss of load event on Unit 2. And we captured some of the data from that, the pressure data.

MEMBER WALLIS: You arranged it to happen?

CHAIRMAN DENNING: Yes, you didn't do this just for us?

MR. FREDERICK: No.

DR. BANERJEE: What's that slide number?

MR. FREDERICK: It's a backup slide. It's not in your book.

DR. BANERJEE: This is one we must have,

right?

MR. FREDERICK: I'll get that for you.

MEMBER SIEBER: Ralph says he has it.

MR. FREDERICK: You see here again the LOFTRAN prediction with the control cases. Generally overall the modeling responds pretty well to the actual event, the difference here being the initial spike. And that's primarily because of the LOFTRAN analysis assumes a 2 second delay from the time the turbine trips until the reactor trips. And that's what's making that. So in reality when we had this event, we didn't see any pressure increase at all.

Just to give you an overall flavor, you know, our safety analysis says that pressure is going to go up 500 pounds. This is an actual event.

MEMBER WALLIS: The LOFTRAN can be off by what? Quite a bit.

MEMBER SIEBER: Fifty pounds.

MEMBER WALLIS: Seventy pounds or something?

MEMBER SIEBER: Fifty pounds.

MR. FREDERICK: We modeled the event exactly as it happened. We were confident that we would get very similar results.

DR. BANERJEE: No, no. But it's much

better you did it this way, really. Because if it agreed too well, then we'd just think you tuned it.

MR. FREDERICK: That ends my discussion on loss of load. We're going to move on and talk about rod withdrawal power unless there's any other questions.

Again, the rod withdrawal power is the limiting event in terms of the DNBR. And this event can be initiated by either a malfunction in the rod control system or an operator error.

As you can see, there's numerous reactor protection trips.

MEMBER WALLIS: So how many rods are withdrawn? How many rods are involved in this?

MR. FREDERICK: Is it one bank, Chris?

MEMBER WALLIS: One bank?

MR. McHUGH: We don't do it that way. We do it by inserting reactivity into the core and we do a range of reactivity insertion --

MEMBER WALLIS: Okay.

MR. McHUGH: -- from 110 pcm per second all the way down to nearly nothing. We don't explicitly model a certain number of rods. We model it in terms of reactivity.

MR. FREDERICK: But that bounds

essentially one bank at maximum speed.

MR. McHUGH: Yes.

MEMBER WALLIS: Well, I'm just trying to figure out what kind of operator error could produce this. Is he limited to withdrawing one bank and so on.

MEMBER SIEBER: Well, you're normally set to withdraw or insert a bank at a time. But if there's a malfunction or an error, it's probably going to be one bank

MEMBER WALLIS: But an operator who had some malfunction in his head, presumably withdraw a lot of rods.

MEMBER SIEBER: I don't think he can do that.

MEMBER WALLIS: He can't do that?

MEMBER SIEBER: He can pick out what bank. You can circle all the rods.

MR. SENA: Again, this is Pete Sena.

For operator action, only one rod bank can be withdrawn at a time unless you're in the overlap region where two banks can be moving simultaneously.

MEMBER WALLIS: So you bounded what's possible?

MR. SENA: That's correct.

MEMBER WALLIS: Yes.

MR. FREDERICK: Some of these trip functions also generate rod withdrawal blocks in the system, but those are not credited as part of this analysis.

As Chris mentioned, we do a range of reactivity insertion rates and we also analyze this at three distinct power levels, as shown there. In total, there's about 90 cases that are run.

Again, this is a very conservative analysis. Initial conditions are biased, again to give us the worst case results in terms of DNBR.

MEMBER WALLIS: Now CHernobyl happened 20 years ago tomorrow. And I guess what they did was they put a lot of reactivity into their reactor. A tremendous amount.

CHAIRMAN DENNING: But not by rod withdrawal.

MEMBER WALLIS: Not by rod withdrawal?

CHAIRMAN DENNING: No. No. They did it --

MEMBER KRESS: They did it by moderator.

CHAIRMAN DENNING: Moderator.

MEMBER KRESS: Negative coefficient. Not moderator. Coolant.

MEMBER MAYNARD: Starting from a very low power.

MEMBER KRESS: Yes, it was extremely low.

MR. FREDERICK: Again, the conservative values for trip functions as well as initial conditions and reactivity feedback reviews. The highest worth rod is actually assumed to be stuck out of the core.

One thing to note is that at Beaver Valley we have actually eliminated the capability to pull rods in the automatic mod. So when our rod control system is in automatic, the rods cannot be withdrawn. So it just eliminates some potential for this event to happen.

Slide, please.

Difficult to see here, I guess, but the curve here basically shows you a plot of what the DNBR result is versus the range of reactivity insertion rates that we've analyzed for both minimum and maximum feedback. Essentially you see the limiting case here, the 1.57 result. We're actually at a very low reactivity insertion rate. Essentially the lower rates cause the system to respond slower so you tend to get a worse result in that case.

The table shows the pre-EPU and the EPU result. Essentially there was very insignificant change in the result. Primarily that is due to the fact that we've changed the correlation from the old correlation to the WRB-2M in which we gained some of the margin. Again, that's associated with the real effect of the RFA fuel and the intermediate flow mixers. So essentially we gained a margin back that the power uprate would have used here for this event by changing the fuel pipe.

And again, I just want to mention that the 1.55 limit that's applied to this event and the other ones, we also have 20 percent of margin in that limit. So it's a conservative analysis and we have margin.

CHAIRMAN DENNING: Not to imply you have the old fuel in there, but you've said before it's something like a 20 percent effect on DNBR, the mixing that's occurring there?

MR. FREDERICK: Yes.

CHAIRMAN DENNING: So that if you had done the power uprate with old fuel, you would have had something like 1.37 or is that over estimating what the impact would be? Okay. Suppose you had done power uprated but you had old fuel in there --

MR. FREDERICK: Right.

CHAIRMAN DENNING: -- would you have gotten about a 1.37 here? Is that your assumption?

MR. FREDERICK: Chris, can we predict that?

MR. McHUGH: I can look that up. I think we actually made those runs. Because we had planned to do the power uprate before we had a complete transition to RFA fuel. I believe I have that on my laptop.

CHAIRMAN DENNING: Okay.

MR. McHUGH: We were going to limit peaking factors on the burnt fuel, and so it wouldn't have been a direct --

CHAIRMAN DENNING: There would have been other things that could have done --

MR. McHUGH: Right.

CHAIRMAN DENNING: -- that it would have reduced the --

MR. McHUGH: Correct.

DR. BANERJEE: Is it 20 percent difference, the new fuel in rough terms?

MR. McHUGH: Twenty percent margin was what they gained by adding the IFM grids to the RFA fuel. So, yes, it was about a 20, 21 percent increase in DNB margin from the old fuel to the new.

DR. BANERJEE: Magic.

CHAIRMAN DENNING: Magic.

MR. BURGER: Yes. If we were to have the old B5H design in there, the peaking, like Chris said, would have been a lower limit that we do have, because you don't have those IFMs and so they would have been the limiting assembly in the core.

MEMBER WALLIS: And all good engineering seems like magic to the layman.

DR. BANERJEE: I think Jeff Hewitt might disagree on this one.

MR. FREDERICK: Okay. The next event that we're going to talk about in some detail is the spurious SI or invertent DCCS. Again, this is another condition II event, which is initiated by either a malfunction in the system which trips the SI signal or perhaps some error in doing some testing of the systems.

The SI or the safety injection signal will generate a reactor trip and a subsequent turbine trip. DNBR for this event really isn't challenged because you're adding cold borated water into the system.

The primary concern here is filling the pressurizer, which again can enlist the valves and actually water through the safety valves.

Again, this is a very conservative analysis and we have actually done better estimate type analyses which show we do not overfill. But in the conservative safety analysis we do fill the pressurizer and lift the safeties.

Now the conservatism that go into this analysis, again, are primarily in the initial pressurizer level again assumed to be setpoint plus uncertainty at a high condition and also at the high T_{avg} condition, which raises the level again.

The initial conditions in temperature and flow are all biased for the worse results.

We actually run this with and without pressurizer heaters, which is a control system but it ends up effecting the temperature of the water, which is one of the inputs into the valve operability analysis. Colder water generally is worse for the valves than hotter water.

Again, two high head pumps start, and that's essentially what fills the system. For this analysis the PORVs which normally would open and prevent the safety valves from opening for this, they're not credited essentially because they are a control system.

One assumption that we also make in here is that when cool water enters the pressurizer as it's filling up, that water is assumed to mix instantaneously with the bulk fluid where you would expect some stratification normally. That, again, minimizes the temperature in the pressurizer and that's an input into the value operability analysis and it makes it more conservative.

Essentially this event ends when the operator takes action to either open the PORVs or shutdown and reset the SI signal and turn off the pumps.

If you look at the next slide, the assumption made here is that occurs at 10 minutes. And we've done simulator studies to assure ourselves that we can meet that limits.

MEMBER WALLIS: Isn't he watching his pressurizer level all this time?

MR. FREDERICK: George, do you want to speak to that?

MR. STORLIS: Yes. I'm George Storlis. I represent Operations and my background has been years of controlling Operations.

The pressurizer level is a key parameter that's monitored and it's the duty of the licensed operator at all times. And managing that level in the crises of an inadvertent SI is of utmost importance.

The automatic features systems prevent the manual shutdown for a period of time at the onset. But the parameters are monitored. The procedures are detailed, emergency operating procedures are followed and the termination of the flow rates when determined not required are of immediate importance.

CHAIRMAN DENNING: What's your backup slide here? Everything you took there, I get curious.

MEMBER WALLIS: Curious about it, huh?

MEMBER SIEBER: Sure do.

MR. FREDERICK: This is just plots from the analysis results. We see here that a pressurizer goes to its maximum level in about 7 minutes.

Next slide.

This shows the pressure as the safety valve cycle opened and closed. In cycling, the number of cycles is another important parameter that we need for our valve analysis. And for this case you can see we have five cycles of the valve before the operator mitigates the event.

MEMBER SIEBER: And that's in a 100 seconds, roughly, 150 seconds?

MR. FREDERICK: That's correct. Yes.

DR. BANERJEE: Do you get any two phase flow through these valves or is it just blowing steam?

MR. FREDERICK: Well, in this case the

pressurizer is full, so --

DR. BANERJEE: So you get water?

MR. FREDERICK: -- a water discharge.

MEMBER WALLIS: But doesn't it flash when it gets --

DR. BANERJEE: Yes.

MEMBER SIEBER: Yes, it does.

MR. FREDERICK: Yes. It flashes in the discharge --

MEMBER WALLIS: Now there's indication of temperature in the discharge line, isn't there, in the control room? Probably rings a bell or something. When there's a temperature in the discharge line from the pressurizer it's measured, isn't it?

MR. FREDERICK: Yes. There is a tailpipe alarm, yes.

MEMBER WALLIS: He's told. As soon as this thing happens, he's told if he doesn't know already.

MR. FREDERICK: Yes.

MEMBER SIEBER: You can assume that the water in the pressurizer is saturated.

DR. BANERJEE: In which case it will get critical fast.

MEMBER WALLIS: Critical flaw at pressure.

Right.

DR. BANERJEE: So do you use a critical flow calculation at that point once it comes out?

MR. FREDERICK: Chris, the safety valve flow model, is that --

MR. McHUGH: I believe it's critical flow -- the first cycle usually starts out with a little bit of steam and then the pressurizer rapidly fills once it opens and the remainder of the cycle is water. And then the remaining cycles are typically all water. The first one does start with steam typically.

MR. FREDERICK: This slide just shows how the pressurizer water temperature drops as your discharging water out of and it's insurging. And again, it's assumed to instantly homogenize and reach a bulk temperature.

DR. BANERJEE: Do you have a graph of the discharge rate? I mean, how the discharge varies? You showed a slide previously, I think that was --

MEMBER WALLIS: It seems to depressurize very rapidly on that slide.

DR. BANERJEE: Yes.

MEMBER WALLIS: There seems to be plenty of flow there.

MR. FREDERICK: The mass flow rate out of the valve, is that what you're asking?

MEMBER WALLIS: Yes.

DR. BANERJEE: It must be very high.

MR. FREDERICK: Yes, it is.

MR. McHUGH: I think I have that information on my laptop.

MEMBER SIEBER: So you're solid, there's no cushioning effect from any steam in there. So the pressure is going to go up very rapidly.

DR. BANERJEE: Can I see the previous slide, please?

MEMBER WALLIS: See how rapidly it comes down?

MEMBER SIEBER: Again, because you're solid.

DR. BANERJEE: Yes. You don't have to do it now, but if you've got it on your laptop, nice to see it.

MR. FREDERICK: Chris, it's in the RAI responses that we submitted, so --

DR. BANERJEE: Is it?

MR. FREDERICK: Yes.

DR. BANERJEE: The 3,000 pages or something, no?

MR. FREDERICK: So, again, yes this

analysis does generate overfill of the pressurizer and as such, the results are essentially used as inputs to an evaluation that we do to determine whether or not the safety valves are going to function under the conditions that we're presenting to them.

The valve evaluation uses WCAP 11677 methodology. And that's primarily based on results from the EPRI valve testing that was done post-TMI where they actually put water through the valves at various conditions and temperatures.

The PORVs are also qualified. We looked at those in terms of water discharge as well as the discharge piping on both the PORVs and the safety valves. We've analyzed all the lines for these conditions and shown that we met the limits.

MEMBER WALLIS: Because you can get choking in the discharge line. Can get critical flow in the discharge line because the depressurization is tremendous.

MR. FREDERICK: Yes. Was it a RELAP analysis to generate the forcing functions on that, Mike?>

DR. BANERJEE: Yes, you can get multiple choking in lines like this, but RELAP wouldn't calculate that, I would think.

MEMBER SIEBER: Yes. There's a number of elbows in that line. I think the analysis that was done was to make sure that the line would stay intact. There's tremendous forces on that line as this slug of water goes --

MEMBER WALLIS: Well, if it chokes at the discharge into the drain tank, that's where you worry because then you get a pressurization of the whole line.

MEMBER SIEBER: Yes. Well, I would imagine almost immediately the drain tank ruptured just with--

MEMBER WALLIS: No. There is a while, isn't there, before that happens?

MEMBER SIEBER: Pardon?

MEMBER WALLIS: Isn't there quite a while before that happens?

MR. TESTA: Yes. This is Mike Testa.

We analyzed the piping from the pressurizer from the pressurizer itself and including the piping down to the PRT. And as Ken said, you know once we overfill, of course, and we're putting water down the line, we used the RELAP computer code to derive the forcing functions. And then incoded that into the piping analysis, piping model to make sure that the piping and the supports would remain intact or acceptable.

MEMBER WALLIS: You don't challenge the rupture disk of the drain tank?

MR. TESTA: No, I don't believe we did.

MEMBER SIEBER: To what, 50 pounds?

CHAIRMAN DENNING: We're running behind, but that's okay. We're going to let this go.

MEMBER WALLIS: You mean we may be a little late tonight?

CHAIRMAN DENNING: Exactly.

MR. FREDERICK: I just have one more area before --

CHAIRMAN DENNING: That's okay.

MEMBER WALLIS: Are you going to do large break LOCA before you --

MR. FREDERICK: Yes.

CHAIRMAN DENNING: Yes.

MR. FREDERICK: One other issue which the Staff raised on the concern here was if the PORVs opened, they wanted us to demonstrate that we had a qualified signal for them to close, even though the PORVs are considered a control grade. However, they do have a signal which comes out of the protection grid systems which close the valves on a low pressure signal from the pressurizer. So the concern here was if you needed to rely on block valves which would be available then that was more of a condition III, that we were able to demonstrate that we do have a qualified signal to close the values.

So summary on the spurious SI, we have analyzed the valves for the water discharge condition was identified and we're convinced the valves can pass water without damage. Likewise, for the PORVs and the PORVs do have the qualified signal to close. And this event will not promulgate a condition III event.

MR. SENA: Again, this is Pete Sena.

I just want to also reemphasize a couple of things.

Jack, you asked about the PRT, the ruptured disk goes at a 100 pounds, not 50 pounds. And additionally, we've simulator crews both units through an inadvertent SI scenario. And they are able to diagnose the event, confirm that we do not have the actual real event such as a LOCA or a tube rupture, and terminate the SI prior to going to solid conditions. And actually, in 2002 we had a real inadvertent SI on Unit 1. And based on that real plant data we also did go solid in that case.

CHAIRMAN DENNING: What was the nature of the event that occurred? How did it --

MR. SENA: What happened in 2002 at Unit 1, one of our main steam isolation valves closed due to a human performance error involving the building of scaffolding. The closure of that valve then resulted in a low steamline pressure from the other two steam generators supplying the turbine. So again, you do not have a valid steamline break, but that's what it sensed at 500 pounds low steamline pressure. So a safety injection signal was actuated and a reactor trip from full power.

CHAIRMAN DENNING: Two high pressure points?

MR. SENA: Yes, two high pressure safety injection pumps actuated, all ECCS pumps actuated. Operators were able to progress through the EOPs and terminate the SI prior to going solid.

MR. FREDERICK: Just to wrap the non-LOCA discussion here. Again, for the analyses that we've done we've shown that we meet all the DNBR limits as well as the pressure limits for primary and secondary. And all the acceptance criteria for the condition II, III and IV events are met at the EPU conditions.

Again, that's it for the non-LOCA and we'll move on to large break LOCA unless there's any questions on that.

For EPU we have, again, gone to the best estimate LOCA methodology, as we discussed before. And, again, this is the original 1996 approved methodology that Westinghouse has used for many plants.

Due to the methodology, there is some benefit in terms of the PCT result as well as changes that were made in the containment and accumulator minimum pressure, which also provides some benefit in terms of the PCT. The container pressure associated with conversion increases the initial operating pressure about 4 psi. And that increase in the back pressure transient that associated with the LOCA event does provide a benefit in terms of PCT. And primarily, this is due to a reduction in what we call downcomer boiling. The downcomer boiling tends to impede vessel refill and that is very sensitive to the containment back pressure.

Also we did primarily for small break analysis we raised the minimum accumulator pressure and that had a small benefit here as well.

So essentially some of the margin that we would lose from EPU we have regained by some of the other plant changes that we've made.

And the results, as shown on the next

slide here --

DR. BANERJEE: What is the small slide?

MR. FREDERICK: Okay. This is a general discussion about what DE methodology is. If you're interested, we can talk about it.

MEMBER WALLIS: No. They're conservative assumptions, all of these things.

MR. FREDERICK: Yes. This basically goes through what assumptions are bounding and then the balance that I talked about how the uncertainties were rolled into the final PCT value.

MEMBER WALLIS: A response surface type of thing, is it?

MR. FREDERICK: That methodology, yes, it does use the response surface.

MEMBER WALLIS: Now what surprised me here, maybe I'm ignorant of these, it looks as if you're limited by your maximum hydrogen generation. Usually the peak clad temperature that limits. And you seem to have an awful lot of oxidation in yours.

MR. FREDERICK: In the BELOCA methodology is --

MEMBER WALLIS: Is it because it stays hot for a long time or something, is that what it is?

MR. FREDERICK: Pardon me?

MEMBER WALLIS: Why are the oxidation numbers pushing the limit? Usually it's the peak clad temperature. Is it because --

MR. FREDERICK: For the hydrogen generation.

MEMBER WALLIS: -- the temperature stays high for a long time or something?

MR. FREDERICK: Right. Matt, do you want to address that in terms of the conservatism?

MEMBER WALLIS: A bit strange to me.

MR. CERRONE: Yes. This is Matt Cerrone with Westinghouse.

Well, first of all, you're right. They do have an extended reflood period so they have a higher PCT and you can see this manifests itself in the core wide oxidation number.

In the methodology, the development of that number is conservative. It's very conservative in that the transient used to generate the numbers developed based on PCTs that are beyond the 9th percentile and it has -- the transient goes for a longer period of time than the PCT transient.

So basically what you're doing is you're making sure that you have a high transient that has a high PCT and has an extended reflood period. Okay.

And then beyond that, the local uncertainty code that we use extends the reflood heat transfer longer in time. So basically it's a conservative number. And the methodology allows for additional COBRA/TRAC calculations to be performed as a measure to reduce the additional -- reduce the conservatism until ultimately you show success at the hydrogen generation, 1 percent acceptance criterion.

Three's an additional work that could be performed to show additional margin in that number.

MR. FREDERICK: Yes. I guess the answer there is we do enough to show we meet the limit and we don't push it beyond that, although there are additional margin to be gained.

MEMBER WALLIS: But the question for Westinghouse, is this an unusual plant where the CWO, the core wide oxidation seems to be the limit here? It doesn't seem to be in my memory a very common thing.

MR. CERRONE: Well, no, it's not all that common, certainly.

MEMBER WALLIS: Is there something unusual about this plant or the method of analysis, or what?

MR. CERRONE: No. It's not unusual. The evaluation techniques were in line with what was in the approved evaluation model. So I think here we're just seeing a PCT and a high oxidation, a higher oxidation number. But like I had said additional work could be performed if it was so needed to generate additional margin and the maximum hydrogen generation number.

DR. BANERJEE: Are you going to show us some curves or clad temperature with times so we get a feel for what's going on?

MR. FREDERICK: I did not include those, no for the large break. I do have some for small break.

DR. BANERJEE: So it would help, I think, in answering some of these questions to see how long the fuel clad temperature remained high or whatever and when reflood came in.

MR. FREDERICK: Matt, do we have the BELOCA WCAPS here?

MR. CERRONE: Yes, I brought Unit 1 and Unit 2 reports with me.

MR. FREDERICK: Okay. Well, the technical reports do have that information if you want to look at it.

DR. BANERJEE: Yes. We don't need all the details, but at least a few for the temperature transient. And they can show it later, maybe.

MR. CERRONE: I could check to see if am electronically, if not I have I think a reference transient with the one break would show an illustration.

MR. FREDERICK: Yes. Just make some copies of those graphs.

DR. BANERJEE: Right.

MR. FREDERICK: And then you can pass them out.

DR. BANERJEE: Of the relevant graphs.

MR. FREDERICK: Right.

CHAIRMAN DENNING: And we could do that during lunchtime and then look at them after lunch if we want to take a look at that.

MR. FREDERICK: So essentially a PCT transient --

MR. CERRONE: OF the large LOCA.

MR. FREDERICK: For the large LOCA.

CHAIRMAN DENNING: Yes. I think particularly --- yes. You'd like to see also if you can in what time period is the hydrogen being generated. Over what time period --

MEMBER WALLIS: Right. Right.

CHAIRMAN DENNING: -- is hydrogen

generation occurring.

MR. CERRONE: It'll help illustrate that. I mean, the time at the transient is above 1700 degree is when you'll be oxidizing.

MR. CARUSO: The transient, though, that you're going to show us is that necessarily the one that produces the maximum hydrogen generation?

MR. CERRONE: No.

MR. CARUSO: That's a problem. Because you probably don't have the graph that generates maximum hydrogen generation. So --

MEMBER WALLIS: It's not the same as the PCT graph.

MR. CARUSO: It's not the same as the PCT.

MR. CERRONE: For each period; blowdown, early reflood and late reflood. A PCT at the 95th percentile is developed in this methodology. In the 95 EM an additional COBRA/TRAC transient's computed where the PCT calculated goes beyond that of the 95th for each of the three periods. So what you do them is you capture the oxidation period above the 95th percentile with the COBRA/TRAC calculation. So you oxidize above the temperatures all experienced in each period at the 95th percentile an you capture the time and temperature.

MR. CARUSO: Is that the scenario you're going to present to us?

MR. CERRONE: Well, I was just thinking through that. The engineering report, I do not believe, provides the oxidation transient that was developed.

MR. CARUSO: That's what I was wondering.

MR. FREDERICK: Yes, I think it will be somewhat representative.

MR. CARUSO: Okay.

MR. FREDERICK: Kind of a general --

MR. CARUSO: Because you just have to be careful, Sanjoy. I think you're looking for the actual transient that generates that .98 percent and you're not going to see that. You're going to see something similar.

MR. CERRONE: Yes. I think what we can do is take each time period --

DR. BANERJEE: The reason, of course, is that what -- at least the way you're putting it, it's a very conservative calculation, right?

MR. CERRONE: Correct.

DR. BANERJEE: Maybe we need to have that when you show -- well, the first thing it would be nice to get the curve which produces that .98, which is relatively close to the limit, right?

The second is that the conservatism maybe should be just listed as a snapshot for us to see so that we can say okay, that .98 is really an upper limit, I mean it's very conservative or something like that. Did I come across? I mean, do you have a feel for it?

MEMBER WALLIS: Because we're discussing a power uprate and it hasn't changed tremendously from .91.

DR. BANERJEE: Right. That was pretty high already.

MEMBER WALLIS: Yes, that as pretty high already.

DR. BANERJEE: It went from a very conservative calculation of .91 to a best estimate of .98?s

MR. CERRONE: Well, we need to keep in mind that the oxidation calculation is conservative even in the original '96 evaluation model using COBRA/TRAC. And keep in mind also that additional COBRA/TRAC calculations could be performed at various power levels to capture the rod power senses throughout the core to give you more and more -- to give you additional levels of margin. The idea is that there's a regulatory limit that we must comply with. And we basically provide a sufficient amount of evidence that we've met that limit.

DR. BANERJEE: Yes. I guess when you say best estimate here, you really have markings in this best estimate.

MEMBER WALLIS: Yes. It's not totally best estimate..

DR. BANERJEE: Yes.

MEMBER WALLIS: There's a lot of conservatism on top of it.

MR. CERRONE: Yes. Especially in the oxidation calculation. We look forward to the ASTRUM, when we move to ASTRUM with this because there is oxidation margin.

DR. BANERJEE: Perhaps that could be at least clarified. Because I'm confused.

MEMBER WALLIS: Well, I think the best estimate number would be much lower if you went from the mean rather this 95th percentile in that.

MR. CERRONE: I would agree.

MEMBER SIEBER: The difficulty, though, is in regulatory space you either meet the number or you don't.

MEMBER WALLIS: That's right. That's

right.

MEMBER SIEBER: And the conservatism you have --

MEMBER WALLIS: And you do have enough to do that. Right. Right.

MR. CERRONE: There's always been plenty of ways to find margin --

MEMBER WALLIS: That's why it came out to .98 because you had to be under one.

MR. CERRONE: Sure. I mean you did a sufficient number of calculations, you show compliance.

MEMBER WALLIS: That's right. I understand.

DR. BANERJEE: Anyway, we want listing the assumptions and conservatism with that curve, then at least we have a feel for it.

CHAIRMAN DENNING: Okay. I think we can proceed.

MR. FREDERICK: Okay. Yes, we're done after this one.

The one thing I wanted to point out here was that the P-clad temperature that you see there for Unit 1 will be a different number as even the draft SER. When we did the original Unit 1 analysis the result came out to 2144. And those original analyses were based on different containment operating conditions that we had in place at the time or we're proposing for the containment conversion. When we changed those initial conditions, we went back and reanalyzed both units. And the number for Unit 1 dropped primarily because we lowered our peaking factor limits associated with Unit 1 analysis because we were seeing an unacceptable increase due to the containment pressure change. So that's the result that we will be reporting essentially is official 50.46 type results is the 21 number.

DR. BANERJEE: What is the reason for the different between Unit 1 and Unit 2?

MR. FREDERICK: In the results?

DR. BANERJEE: Yes.

MR. FREDERICK: The major difference between the plants is in the downcomer area. One unit has what they call thermal shields and the other one has the neutron blanket. And those represent, basically, fairly significant thermal masses but they are different between the plants. So Unit 2 tends to be a lot less sensitive to downcomer boiling type conditions, low pressure in containment than Unit 1.

Initially actually Unit 1 resolve was

actually much higher, was 2144 for similar input conditions. For example, the peaking factors were originally all the same. The result here is that they're not that different here, but actually Unit 1 here is restricted to a lower peaking factor limit than 2. The difference is in the plant is reflected in the analysis.

DR. BANERJEE: Raising of the containment pressure didn't take care of this downcomer boiling problem?

MR. FREDERICK: It helps, but it does not completely eliminate.

That's all I had on large break. I guess we're going to shift over to the NRC now.

CHAIRMAN DENNING: Yes. We'll at least start the Staff's presentation here and then we'll see if we want to have a breaking point in the middle of it, if that's okay.

MR. MIRANDA: Okay. The answer to your first question is we're using this overhead projector because I have some transparencies with some transient plots on there and I'd like to have the ability to draw on them.

My name is Sam --

MEMBER WALLIS: On the screen, whatever

you do.

DR. BANERJEE: Well maybe draw on the screen so we can have it changed and focused.

MEMBER SIEBER: We already tried that.

MR. MIRANDA: My name is Sam Miranda. I work at the PWR Systems Branch of NRR as a technical reviewer.

I've been with the NRC for a little more than 5 years. And before that time I worked for Westinghouse as a nuclear safety analyst for almost 25 years, during which time I used LOFTRAN code and worked with the author of LOFTRAN, Toby Burnett to write several routines in LOFTRAN.

First I will go quickly through the --

DR. BANERJEE: Where are these slides?

MEMBER SIEBER: They're in here, I think. I'm going blind.

MEMBER WALLIS: That's almost as good as the other one.

MR. MIRANDA: Okay. For the EPU at Beaver Valley there is no change in the fuel design. By the time the EPU will be implemented, the entire core will be composed of robust fuel assemblies. And there's been no change in the methodology used for the nuclear design.

As far as thermal hydraulics is concerned, since the entire core is robust fuel assemblies, there's no DNBR penalty for the fuel transition. And the THINC IV code has been replaced by the VIPRE code in the DNBR evaluations.

Both --

DR. BANERJEE: The difference between these codes?

MR. MIRANDA: The VIPRE code seems to be more flexible. You can model cores with, for example, hexagonal lattices rather than just square lattices. There are features in VIPRE that allow it to do things that THINC has problems doing.

DR. BANERJEE: Are these subchannel codes or what?

MR. MIRANDA: They're detailed core models where you can have a hot channel an you can have surrounding fuel assemblies and you can also model the fuel itself, the pellet, the gap and the clad, calculate temperatures and stresses and heat flux.

Both the revised thermal design procedure and the standard design procedures were used in the analyses depending upon the limits of these methods and the requirements of the accident analyses themselves, as discussed earlier by Mr. Frederick.

This is a review of the large break LOCA analyses and as compared to the 10 CRF 50.46 limits.

CHAIRMAN DENNING: And you're showing the older version of the peak clad temperature for Beaver Valley 1?

MR. MIRANDA: The older version?

CHAIRMAN DENNING: That's not 2144 anymore.

MEMBER SIEBER: Yes, that's one cycle before the cycle --

MR. MIRANDA: Revised.

MR. FREDERICK: Ken Frederick.

That is the value that we had on our original analysis before we reanalyzed.

MR. MIRANDA: Yes. We didn't incorporate the new number in this slide, but yes the licensee has submitted a new number.

MEMBER WALLIS: This is something that we don't have, this slide, is that right?

DR. BANERJEE: Do we have this slide?

MR. MIRANDA: No, you don't have this slide. This was added at the last minute.

CHAIRMAN DENNING: So you'll get us a copy of this. Okay. But there's nothing new on there?

MR. MIRANDA: No.

CHAIRMAN DENNING: Stick it up just another second. That's basically just supposed to show us what the applicant calculated.

MR. MIRANDA: Right.

CHAIRMAN DENNING: Right. And we've already seen that.

MR. MIRANDA: And to show you that the limited have been met, yes.

CHAIRMAN DENNING: Okay. Good. Thanks.

MR. MIRANDA: I'm going to get into a discussion here about the margins and acceptance criteria and then which will lead into a discussion of the results for three examples of transient analyses. And this is going to be very basic.

We have on the left hand column the ANSI criterion that defines conditions I, II, III and IV events and the acceptance criteria and how we get from there to the analysis criteria.

The ANSI standard from 1973 defines anticipated transients condition II events, otherwise known as anticipated operational occurrences. As events that could occur during the calendar year of operation at a plant. And it's defined basically as an event that basically requires no more than a reactor trip. Plant trips you correct a condition and you're back to power in short order.

There are basically three analysis criteria that apply to condition II events. One is that the RCS does not overpressurize and also the main steam system does not overpressurize. Another is that you have no fuel clad damage, and this demonstrated by showing that you meet the DNBR safety analysis limit. And finally, that the condition II event does not develop into a more serious event. And this criterion is designed to prevent a shortcut or short circuit in the sense that you can't have a condition III or IV event that originates as a condition II event with a condition II frequency of occurrence. Because a condition III or IV event has other acceptance criteria.

And as far as analyses are concerned, this last condition that the event does not promulgate into a more serious event is shown by demonstrating through analyses that the pressurizer doesn't fill. And this is done to preclude the possibility of passing water through any of the pressurizer relief or safety valves which may not be qualified for water relief. And in deterministic accident analysis if a valve is not qualified for water relief, it's assumed to stick upon. And a stuck open valve then constitutes a small break LOCA in the steam space of the pressurizer.

Another option to satisfy this criterion is to qualify the valves in question, either the pullers or the safeties or both. And in this case Beaver Valley is qualified to safety valves.

Condition III events which may occur during the lifetime of the plant, there is some allowance for fuel clad damage. And these are governed mainly by the dose consequences which have to meet the 10 CRF 20 release limits. But in many cases in accident analyses this is satisfied merely by meeting the more stringent condition II criteria.

As far as condition IV events are concerned, the limiting faults also dose criteria apply, 10 CFR Part 100. And, again, a lot of the accident analyses, steamline break is one example, where this is satisfied by meeting the condition II criteria.

There's also 10 CFR 50.46 with the PCT limits and so on. And that's all aimed at the ANSI standard from 1973 which talks about maintaining the ability of protection systems that are needed to mitigate the event. And that goes to the -- of the core and maintaining core geometry.

In accident analyses found in Chapter 15 the non-LOCA events, this is often shown by showing that there's no boiling in the RCS system and no hot leg saturation. And this happens to be a Westinghouse internal criterion. By showing that there's no boiling in the RCS, you can show that the core will not uncover and the event ends there. The evaluation need not continue to more complicated factors. It also happens, it's very convenient for Westinghouse since LOFTRAN is not capable of modeling a two phased flow. So when you reach a hot leg saturation you should be done with that analysis.

There's another category here they added, ATWS. ATWS is not covered by this ANSI standard. ATWS was invented in 1969 by an ACRS consultant named Dr. Epler. And the Staff issued guidelines for analysis of that ATWS and acceptance criteria in WASH-1270. And ATWS was the first category that was to be analyzed according to a probabilistic safety goal of no core damage. I believe it was something like 10 to the minus 5, then it went to 10 to the minus 7, then it went back to 10 to the minus 6. But the various vendors submitted analyses in 1974 to show the consequences of ATWS. And this issue continued until the promulgation of the ATWS rule in 1986, 10 CFR 50.62 which actually does not require analyses. It just requires the installation of certain hardware.

For PWRs this is a diverse SCRAM system and an ATWS mitigation systems actuation circuitry. And for Westinghouse plants it's just the AMSAC system, because Westinghouse demonstrated that DSS was not justified.

ATWS analyses are conducted on a best estimate basis. And the principal criterion there is RCS overpressurization. And the level C stress limit was chosen as the acceptance criteria, 3200 psig. And this is based on review of the various components of the RCS system and picking the weakest component. In many cases that is the reactor coolant pump cases.

And another item that's important in this level C stress limit is the valve disks for valves that are needed to proceed to safe shutdown. The pressure has to be kept to a level such that there would be no deformation of the valve disks so that they remain operable and the plant can proceed to safe shutdown after a ATWS.

This is similar to what you've seen before. This example, which is based on the WRB-2M correlation shows that the correlation limit, the 95 percentile ability, the 95 percent confidence level is 1.14. And this includes uncertainties that are encountered during the development of the correlation.

And then the design limit 1.22 includes the operational uncertainties on power level, temperatures and flow rate mainly.

And then to this is added some margin. For Beaver Valley's case it's about 21 percent. And this margin would include, for example, transition core DNBR penalty, would include rod bow. In this case, the transition core, the DNBR penalty doesn't apply.

For the reactor coolant pressure boundary, I've chosen the level C stress limit, I'll call that the best estimate since it's used for ATWS analyses. And then the safety analysis limit is the 110 percent of design pressure, which leaves us a margin of about 17 percent.

CHAIRMAN DENNING: One second. On the 1.55, Staff has accepted lower values than 1.55 for these kinds of transients, is that true on a CHF?

MR. MIRANDA: Yes. Yes. That's true.

CHAIRMAN DENNING: This is a reasonably conservative value from your interpretation?

MR. MIRANDA: Yes. Yes, it's reasonable. I've actually compared to other plants, this has more margin.

CHAIRMAN DENNING: Thank you.

MR. MIRANDA: Now I'm going to talk a little bit about margins and where they're found. And in the first grouping is in the acceptance criteria themselves. And from a prior slide we saw that the analysis criteria are more stringent, there's more margin in there in order to show that the standard acceptance criteria met. The standard acceptance criteria sometimes can be a little bit hard to measure, but the analysis criteria have to be measurable.

So in the acceptance criteria themselves, some events are analyzed according to more stringent criteria. For example, the steamline break, a condition IV event, or the complete loss of flow, a condition III event, are both analyzed according to condition II acceptance criteria meaning no clad damage.

Then there's also some margin between the acceptance criteria and the standard in terms of shortcuts like the pressurizer no fill criterion. And also as far as the fraction failed fuel rods. And the condition III and IV event, for condition IV events for example, the fraction of failed fuel rods is largely determined by the dose consequences. And the fraction of failed fuel rods some value is chosen that is known to produce acceptable dose consequences. In a prime reading for Ginna, for example, there was a statement in the Ginna SE which talked about the assumed level of failed fuel rods. This refers to the practice of doing an analysis, doing a rod census and calculating the number of rod failure. And if it meets some predetermined level, for example, 10 percent, then it's acceptable. Very often that number is much less than that, maybe 2 or 3 percent. The 10 percent value would be used by the dose people as standard practice. Get the dose consequences for a 10 percent level of fuel rod failures when the analysis actually shows something much less.

In the initial conditions and parameter values, the initial conditions for the accident analysis are taken in the conservative direction. Power level, for example, would be at 102 percent power. RCS temperatures depending upon the accident analysis and what they are looking for, very often the RCS temperature would be about 4 degrees higher than nominal. There's also some level of steam generator tube plugging that's assumed as well as pressurizer and steam generator water levels.

The protection system setpoints are also taken in the conservative direction.

MEMBER WALLIS: This is what's done by this plant. It's not always done, is it?

MR. MIRANDA: It's always done, yes.

MEMBER WALLIS: Always done?

MR. MIRANDA: Always done.

MEMBER WALLIS: Even in a best estimate with uncertainty, you still have these conservatism?

MR. MIRANDA: Well, these are not best estimate analyses. These are conservative analyses.

MEMBER WALLIS: Conservative?

MR. MIRANDA: Yes.

In practice, taking all of these uncertainties in the conservative direction could actually wind up with a plant in a configuration that's not possible physically, but they do it anyway. You might, for example, take the under block values for core reactivity and beginning of life values for temperatures.

Core reactivity feedback, for example. They might take a most negative moderator temperature coefficient which would occur at end of life, it might be much more negative than actually expected. And then at beginning of life you would have a zero coefficient or positive coefficient. The object there is not only conservatism, but also to produce a very wide range of analyzed space so that in the future for core reloads of different core designs with different core moderator temperature coefficients and other coefficients, doppler for example, if those values for the characteristic of the core reload fall within this range, that would tend to eliminate the need for new analyses.

And Westinghouse calls this their reload safety evaluation checklist.

There's also margin added to key parameter values used in the accident's analyses. Rod drop time, for example, was typically 2.8 seconds. The actual value is closer to 1½ seconds. Safety injection flow if it's conservative to have a minimum flow of, then the pump, the performance codes are taken at a minimum value.

Decay heat generation is another example. Decay heat generation --

MEMBER WALLIS: Is this stuff in a Reg. Guide somewhere or is it actually in the rule, or is it just the way it's done?

MR. MIRANDA: This is the practice. Yes.

MEMBER WALLIS: This is precedent. It's not rule?

MR. MIRANDA: No. It's experience.

MEMBER WALLIS: This is the way it's normally done?

MR. MIRANDA: Yes. Yes.

Decay heat generation is another one I'm sure you're familiar with. It's either 1971 model plus 20 percent or a 1979 model plus 2 sigma.

And Scram worth, typically for a Westinghouse plant that might be 4 percent. The actual value is closer to 6 percent because they assume that the most reactive rod is stuck out of the core.

Just in response times. The same thing. Typically rods don't get begin to drop until maybe 2 seconds after the signal was received. And that actual value is closer to 1 second or .8 seconds

Also response times in terms of pump startup times to reach full speed or opening valves. For example in the safety injection system before flow delivery could occur to the RCS, it might be 10 seconds. It's actually less than that, especially if you consider for example the relationship between flow area and valve position.

MEMBER WALLIS: All of this sounds qualitatively good. But until you put it in a terms of a probability distribution or something, I don't really know what you're gaining. I mean you say we're going to assume 2 seconds when reality is more like 1. But presumably it's one with some uncertainty.

MR. MIRANDA: Yes.

MEMBER WALLIS: Your two is somewhere way beyond the uncertainty bound or it's sort of 99.9999 percentile or something, or what is it? It sounds good, but I don't have an idea.

MEMBER SIEBER: You do rod drop tests and I think two is the ultimate limit, but most of the time a rod will drop around 1 second or 1.2 seconds.

MEMBER WALLIS: That's a qualitative statement.

It all sounds good, but I just wonder why it isn't all put into some soundness, sort of probabilitistic basis and then we can do a bounding best estimate with uncertainty.

MR. MIRANDA: This method predates PRA.

MEMBER WALLIS: Yes, it does. It seems to be a bit archaic. That's why you're using this particular projector, isn't it?

MR. MIRANDA: It's consistent, yes.

MEMBER SIEBER: It's structural.

DR. BANERJEE: But it actually focuses better.

MEMBER WALLIS: The focus is much better, right.

MEMBER SIEBER: Structuralist.

MEMBER WALLIS: It's cheaper to do it this way?

DR. BANERJEE: Sounds like these are sort of limiting values that you use?

MEMBER SIEBER: Yes.

MEMBER WALLIS: They are.

DR. BANERJEE: One end of the probability distribution?

MR. MIRANDA: That's right. It is possible sometimes to do sensitivity studies where you isolate some of these things and you might do the same analysis, for example, with a 2.8 second drop time and a 1 second drop time and see what effect it has on your parameter of interest. And you can do this for hundreds and hundreds of cases and come up with some kind of a relationship. But it hasn't been necessary as long as you show that the safety analysis limit is met, there's no point in going any further.

DR. BANERJEE: And maybe you don't know the probability distributions anyway, you know.

MEMBER MAYNARD: Right.

MR. CARUSO: That costs money to determine that.

MR. MIRANDA: Well, okay.

MEMBER SIEBER: Well, from a legal standpoint this method is much easier to defend; you either make it or you don't. You build a box and the reactor fits in there, it's good. If it doesn't fit in there, it's not good.

MR. CARUSO: And if you have a problem meeting your criteria at some point, then you go look at an individual factor and say, well, is it necessary for me to refine that value in order to meet the criteria. And then you have to develop the data that's needed to support the value that you use. But it's easier to use the limiting value until you need to.

MEMBER SIEBER: That's the old regulatory system. And it is still used pretty widely.

MEMBER WALLIS: It produces the same results on Monday as it does on Tuesday.

MEMBER SIEBER: That's great.

MEMBER WALLIS: Well, is an interesting --

MEMBER SIEBER: And Plant A and Plant B look the same if they are the same.

MR. MIRANDA: There' margin also in the methods used in the analyses. We heard a little bit earlier about critical flow through the pressurizer safety valves. LOFTRAN has several critical flow correlations in it and you use the appropriate model.

For example, steamline break you might want a very high flow through the break.

For a case where you're worried about RCS overpressurization and you're looking at flow through the pressurizer safety valves, you might use a flow correlation that produces a lower flow.

And it has, for example, homogeneous equilibrium subcooled and saturated models, and moody models.

Again, for steamline break make an assumption that the steam break flow is dry steam. This maximizes the cool down that the steam break produces in the core and maximizes the core reactivity response.

In actuality, a steamline break would have considerable entrainment in it. And I know this from experience because Turkey Point Unit 3 had a steamline break in 1971 when they were doing pre-startup testing. The core was not loaded at the time, but they blew a safety valve off the header on the steamline and the steam generator blew dry in a time that was much faster than predicted by the computer code. And the difference was attributed to water entrainment.

DR. BANERJEE: But I guess conservative here must be carefully defined, right? It's conservative with regard to some specific parameter that is of concern, like peak clad temperature, reactivity or whatever.

MR. MIRANDA: That's right. We'll see some examples of that in the plots.

There's also as far as --

MEMBER WALLIS: What you're describing is just what these guys did at Beaver Valley?

MR. MIRANDA: Yes.

MEMBER SIEBER: Yes.

MR. MIRANDA: Yes. This is standard Westinghouse methods.

MEMBER WALLIS: I thought Westinghouse had better methods now.

DR. BANERJEE: Well, only when they need it.

MEMBER SIEBER: The answer is no? This is the licensing approach.

MR. MIRANDA: Yes. This is methodology that the Staff has seen before, it's familiar with and has approved of.

LOFTRAN and RETRAN, but in this case we're talking about LOFTRAN has a derivative method. They call it to estimate the DNB ratio. And this is a shortcut.

Rather than go through the VIPRE analysis to actually calculate a DNB ratio, LOFTRAN has the results of sensitivity studies of the effect on DNB ratio due to changes in pressure and temperature. And during a transient, as you move through the transient and you change temperature and pressure, it calculates a DNB ratio. And this deliberately programmed into LOFTRAN to give you a lower than expected DNB ratio. And then the practice is depending upon what the DNB ratio is. For example, if you do a raw hydraulic power analysis, then you come up with a DNB ratio of 1.5 and the safety analysis limit is 1.55. You know that 1.5 of value is conservative from LOFTRAN but you can't prove it. So you take some stake points from the analysis and you put them through a VIPRE analysis and you come up with a better DNB ratio. And that's very often much higher, 1.6, 1.65, whatever. But it does eliminate a lot of VIPRE analyses to go through this estimate.

MEMBER WALLIS: I believe this is all going back to the days when it was expensive to use a computer?

MR. MIRANDA: Yes. It goes back to those days. And furthermore, not only was it expensive to use the computer, but you had to use several codes.

MEMBER WALLIS: Took a long time to run, too, I think.

MR. MIRANDA: Took a long time to run. And you had to physically take those stake points and put them into another --

MEMBER WALLIS: Take some perforated paper from one computer to another, or something.

MEMBER SIEBER: And boxes of cards.

DR. BANERJEE: Boxes of cards.

MR. MIRANDA: Yes. Yes. And a technician with a piece of graph paper.

MEMBER SIEBER: Yes.

MEMBER WALLIS: Now are we back in the '60s or something here? This is very interesting.

MR. MIRANDA: Yes. Actually we're in the '70s.

MEMBER WALLIS: Back in the '60s.

MEMBER SIEBER: No, that's 1970s technology.

MEMBER WALLIS: We should all feel really young and full of energy, right?

MR. MIRANDA: LOFTRAN was written in 1970 and was in full use for licensing analysis by 1971. LOFTRAN is an abbreviation for loss of flow transient and it was written to do the loss of flow transient analysis for the Zorita Plant in Spain, a one loop plant.

As far as transient assumptions are concerned, the worse single act of failure in the protection system is assumed, and this goes to the IEEE 279 requirements 279 requirements. And then again, the scram worth is based on the most reactive rod stuck outside the core.

And we heard a little bit about this earlier, about no credit for operation of control grade systems. And typically these are the pressurizer PORVs, heaters and spray. And such systems are assumed not to be operating in a transient unless their operation would tend to make the transient worse.

Sometimes you'll see in a set of accident analyses several cases performed with and without the operation of the control grade system to see the effect.

And then there are some trips that are just not taken credit for. And the example of the reactor trip on turbine trip was alluded to earlier. And also the rods don't fall into the core when offsite power is lost. The rods fall into the core only after reactor trip signal is received.

I can discuss, by the way, before I get into the transients, if you're interested I could talk a little bit about the overtemperature delta T trip and how that's determined.

At this point I'll go to the conclusions. The bottom line, very simple, when we look at an analysis, for example the DNBR limit. If the minimum calculated DNBR from the transient is greater than the safety analysis limit, then the analysis is acceptable.

If the minimum calculated DNBR should equal the safety analysis limit, then the analysis is still acceptable because we know that we have margin in both the limit and in the accident analysis.

And if the minimum calculated DNBR should fall below the safety analysis limit, now we can't accept the analysis because it hasn't been demonstrated that there's adequate margin still available. There's obviously been some erosion of that margin and we have no idea of how much is remaining. And this goes back to what you said, Dr.

Wallis. We don't have that relationship between the best estimate value and the uncertainty.

MEMBER WALLIS: Now when the licensee calculates these numbers, he's not able to tweak his code to make it less than or more than? We all know that by changing nodalization and time steps and all sorts of things you can tweak codes to get different results. He's not allowed to tweak his code? How do you prevent him from just dialing a lot of tweaks and eventually getting within the regulations?

MR. MIRANDA: Well, we can't prevent him from doing that. And if the modeling has been accepted; an acceptable model should not be very sensitive to things like time steps and nodalization for a non-LOCA analysis.

DR. BANERJEE: They generally are, that's the problem. I mean, essentially all these finite difference code depend on nodal volumes and time steps. They're not mathematically convert in any sense of the word. They're too nonlinear. There's also some weird things in them.

MEMBER WALLIS: Like the business of matching the currant number at one and not somewhere else, and therefore getting distortion there.

MR. MIRANDA: You can tweak the code a

little bit, but only a little bit with LOFTRAN because LOFTRAN is not like a LOCA model. It's a hard wired simulation. It has a pressurizer. It has steam generators. And you have very little leeway as far as nodalization is concerned. You can put three nodes in the hot leg or you can put 20 nodes in the hot leg; the results should not be that much different.

The same thing with the core. You can put several nodes axially and radially in the core but, it won't have that much of a difference.

MEMBER WALLIS: That's why we've always said that the Staff should have the ability to run these codes itself. Find out how sensitive they are to these various things rather than just taking something submitted by the licensee, who has obviously optimized things to make it look good.

MR. MIRANDA: As a matter of --

MEMBER WALLIS: Or he has the chance to do that, let's say. But you don't have these Westinghouse codes run by the Staff, do you?

MR. MIRANDA: Well, for Beaver Valley and Ginna we do have use of the LOFTRAN code. We have access to the LOFTRAN code through Westinghouse's office in Rockville. And we have the LOFTRAN manual and we have the safety analysis standards.

MEMBER WALLIS: When they report a number like, whatever it is, 2748.5 when it should be 2750, you can run your own LOFTRAN or whatever it is and figure out if you can get it to 2502.1 or something?

MR. MIRANDA: We could, yes.

MEMBER WALLIS: 2750.3 or whatever it is.

MR. MIRANDA: Yes. Yes. We could change a few parameters --

MEMBER WALLIS: You have a really good idea of how much tweaking they could do to get what they want?

MR. MIRANDA: I've done this tweaking myself.

MEMBER WALLIS: That's it, you're an insider.

MR. MIRANDA: There isn't that much you can do. You might be able to change the result by a couple of psi, but unless you make some basic changes in the assumptions. You would need, for example you would need to change the critical flow model that you're using. And making changes like that require justification. You need to have a reason for doing that.

MEMBER WALLIS: It really takes a Staff member who has done this stuff him or herself to be able to understand what the licensee is doing or what Westinghouse is doing. Otherwise you can be bamboozled.

DR. BANERJEE: Or have an equal capability, which is not LOFTRAN, which is in your hands.

MEMBER WALLIS: Like TRAC?

DR. BANERJEE: Whatever, yes.

MEMBER SIEBER: Yes. Well, LOFTRAN is only one code. There's a lot of codes that are used here.

DR. BANERJEE: Yes.

MEMBER SIEBER: There are VIPRE, MAAP.

DR. BANERJEE: At least to keep them honest to do a few spot checks here and there.

MR. MIRANDA: Yes. And we have done a couple of those.

MEMBER SIEBER: They do audit. You do audits?

MR. MIRANDA: Yes. We did an audit for Beaver Valley in November of last year, three days at Westinghouse's offices in Pittsburgh where we looked at the --

MEMBER WALLIS: When are we going to take a break?

MR. MIRANDA: -- analyses, we looked at

the calculation notes behind the analysis and also the safety analysis standards. And we talked to the people who performed these analyses.

CHAIRMAN DENNING: Sam, let me interrupt you at this point. I think this is a good breaking point, would you not agree?

MR. MIRANDA: Sure.

CHAIRMAN DENNING: Well in that case, we're going to adjourned then until by that clock 25 after 1:00.

(Whereupon, at 12:30 p.m. the meeting was adjourned, to reconvene this same day at 1:30 p.m.)

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

1:30 p.m.

CHAIRMAN DENNING: Okay. We are now back in session.

And, Sam, you can start anytime you want.

MR. MIRANDA: Okay. I will step through three example of non-LOCA transients. And we have the same three transients that Beaver Valley was talking about earlier.

The first is a loss of external load. And this is the event that causes a very high reactor coolant system pressure. And followed by the rapid draw of power for the channels to DNB. And finally the spurious actuation of ECCS. And this event is the one that we look at in order to show that the event will not progress to a condition III or IV event.

The first event, the loss of external load I might comes in several varieties. There is a condition I loss of external load, an operational transient which is also known as a load rejection. We can reduce load by 50 percent and show that the plant will not trip.

There's also a loss of load ATWS, which is the limiting ATWS event in terms of pressure which will reach pressures very close to the 3200 psi limit.

The loss of external load, and moving to the earlier discussion, the best estimate case that showed there was no difference between pre-EPI and post-EPU, I might add that in that instance if you have a loss of load and you have the steam dumping available, basically that amounts to a 60 percent loss of load. Steam dumping to the condenser will take up about 40 percent of nominal steam flow. So comparing that to an accident analysis loss of load, a 100 percent load rejection, there's a big benefit there; first of all. And secondly, if you use the pressure control system pulls and spray the spray will be working during that event. So that seeing two curves that are identical is not a surprise because here you only have a 60 percent load rejection and you have pressure being controlled by the sprays. And that is very likely to be more than enough to handle the 8 percent power increase.

So for this event there are two cases analyzed. I'm going to talk about both of them and you'll see why in a few minutes.

The first case we have a case that's analyzed for channels to the DNB. And in that case as expected the overtemperature delta T trip is reached. And the minimum DNBR occurs shortly after the rods begin to drop.

Typically the minimum DNBR will occur even before the rods reach of the bottom of the core. When most of activity has been inserted, transient is already -- DNB ratio begins to increase again.

One thing I would look for in as a reviewer in a case like this would be for a reactor trip that comes from the part of the reactor protection system that is designed to protect against a parameter of interest. In this case we're worried about DNB and the reactor protection system function that protects against DNB is overtemperature delta T. So if I saw a trip occurring from another source that is not related to DNB, I would have questions.

So here we have the overtemperature delta T trip operational.

The second case is the case that challenge the RCS pressure limit. So here we have the nuclear power and heat flux. Then I have drawn on this the time of the reactor trip right here. And you'll see that the nuclear power begins to drop quite soon. Heat flux begins to drop just a little bit later. And that's just due to the thermo-lag heat flux through the fuel.

And this is the pressure and pressurizer volume.

MEMBER WALLIS: Now it peaks out at the flat top because it actually blows a relief valve, the pressurizer?

MR. MIRANDA: This is the answer to your question right there.

MEMBER WALLIS: Okay. That's it. Thank you.

MR. MIRANDA: Now this is an example of conservatism in the setpoints. The pressurizer safety values are set to open nominally at 2500 psia with a tolerance of plus or minus 3 percent. This is Beaver Valley 1. And in this case since they are looking for a low DNB ratio, they're want to keep the pressure low. Therefore, they're using the low setting on the pressurizer safety valves, opening them at 24, 25 psia, nominal minus 3 percent.

They're also using pressure control. Pressurizer spray and pressurizer power operator relief valves. So you see the first plateau is when the relief valves open at 2350 psi and a second plateau is when the safety valves open. Both of those serve to keep the pressure low and keep the DNB ratio low.

And then finally as a verification that

this is not an event that could proceed to a more serious event, we see that the pressurizer does not fill.

MEMBER WALLIS: Where is full pressurizer?

MR. MIRANDA: It's about 1428 cubic feet. 1420 cubic feet for the pressurizer and another 28 cubic feet for the surge line.

CHAIRMAN DENNING: Now, in this case if they had the valves opening later, would it have threatened the pressurizer more filling the pressurizer?

MR. MIRANDA: If the valves were opening later --

MEMBER WALLIS: It's not turned around by the valves.

MR. MIRANDA: No, actually if the valves opened earlier, the pressurizer level might be higher because you're squeezing the steam out.

This is the last of that transient. This mainly shows that the reactor coolant system pressure here, this is the value that comes very close to the 2750 psi limit. And this is higher than the pressurizer pressure because this pressure is measured at the reactor coolant pump discharge. It's the highest pressure in the system

MR. CARUSO: Do we have that one?

CHAIRMAN DENNING: I don't think we do.

MR. MIRANDA: No. No, I just added that just to show this. I don't think you have any of the curves, do you?

MEMBER KRESS: Yes.

MR. MIRANDA: Okay. I just added that.

And then finally we have the parameter of interest, the DNB ratio to show that it doesn't reach the safety analysis limit. The limit is 1.55. This is the same curve that the reactor trip noted there. And you see that the reactor trip and the minimum DNB ration are related. The reactor trip is what mitigates this event. This is the classic definition of a condition II event. All it takes is a reactor trip.

Now we have another case without pressure control. This is a case that's designed to maximize the reactor coolant system pressure. And this will have a higher pressure than the previous case. It's still within the limit.

A similar behavior, there's the reactor trip and the response in nuclear flux and heat flux. And this occurred you saw earlier today was the peak reactor -- here's a peak pressurizer pressure. And then you come down, on the way down, you see there's a little plateau here. This is at 2575 psia

MEMBER WALLIS: It doesn't look right. Oh, yes it does. It's okay.

MR. MIRANDA: 2575 --

MEMBER WALLIS: Yes, it's okay.

MR. MIRANDA: -- that is nominal subpoint for the pressurizer safety valve.

MEMBER WALLIS: Around the peak. There's a very sharp peak there.

MR. MIRANDA: Oh, that's the reactor trip.

MEMBER WALLIS: The reactor trip is what cuts if off at 2700 or something. That's the way you want to avoid. It just trips in time, doesn't it?

MR. MIRANDA: Yes. Yes. That's right.

MR. FREDERICK: This is Ken Frederick.

Actually, what we've seen is that when the valves open is where we reach the peak. We actually ran an additional case where we didn't credit the first trip, we credited the second trip. And that trip actually occurred after the peak. And the peak was pretty much the same but it occurs right when the valves open.

MEMBER WALLIS: So it's a valve opening that causes the peak?

MR. MIRANDA: Well, the valve opening helps. In fact, this 2575 here, that's when the valve begin to reseat. And that's the higher -- that's the nominal setpoint plus 3 percent. Because the object here is to maximize pressure. So they're using the higher setpoint for the safety valves. And also in this case we see that the pressurizer doesn't fill.

This is another curve that you don't have. This is the reactor coolant system pressure to show the maximum value. That's the number that you saw earlier, the 2747 psia.

We can skip this one.

MEMBER WALLIS: So you're making FENOC's presentation for them here?

MR. MIRANDA: Excuse me?

MEMBER WALLIS: This is all their results, right?

MR. MIRANDA: Their results, yes.

MEMBER WALLIS: And so you're just showing that you understand them? There's nothing that you did to calculate anything separately?

MR. MIRANDA: Actually, I did --

MEMBER SIEBER: He probably do it.

MR. MIRANDA: I did the analysis that Mr. Frederick was referring to.

MEMBER WALLIS: Oh, you did the analysis that they're using now?

MR. MIRANDA: No, no, no no. The one where they took the second trip, I verified the LOFTRAN ran.

MEMBER WALLIS: Okay.

MR. MIRANDA: That is designed to show that these valve sizing meets the ASME design criteria. That's according to Section 5.2.2 in the FSAR.

Any questions on the loss of load?

As I said, the loss of load there's a different of different variation. We've already referred to four variations. The accident analysis, the condition I event which could be a load rejection anywhere from 40, 50, 60 percent, the ATWS analysis; that's three variations.

Okay. Rod withdrawal with power. Rod withdrawal with power is actually a series of transient analyses that could be -- let's see, close to a 100 different analyses that are performed. I'm going to talk about two example.

One, at full power and 80 PCM reactivity insertion rate, a high reactivity insertion rate and another one at full power with a very slow reactivity insertion rate.

And these two events show that the high neutron flux trip will protect against a high insertion rate and the overtemperature delta T trip will protect against very slow insertion rates.

There are other trips that come in, but these are the ones that we look for in a rod withdrawing power since these are directly related to the event.

Here's the high reactivity insertion rate. And we see we get the high flux trip. And there's about a half a second delay and the rods begin to fall. And as the rods fall, you can see the power dropping. This is a very short time scale. It's only 7 seconds.

And since this is a condition II event, they're also in addition for looking for the DNB ratio limit, we're also making sure that the pressurizer doesn't fill. In this case there's lot of margin to filling.

DR. BANERJEE: What is the water volume for filling the pressurizer?

MR. MIRANDA: 1400 cubic feet plus another 28 cubic feet for the surge line.

So the DNBR safety analysis limit is 1.55

and this particular case the ADPC per second reactivity insertion rate at full power meets the limit.

And then for the slow reactivity insertion rate, you can see this is a much longer transient. We have about 2 minutes represented here. And the trip comes from the overtemperature delta T trip. And this event, by the way, is crucial to determining the setpoints for the overtemperature delta T trip.

And in this case we see that the pressurizer power operator relief valves opened right here. But the pressurizer is still not full.

And here's the DNB ratio. And in this case we come closer to the limit. I think that might be the 1.57 case. DNB ratio is reached soon after the -- while the rods are falling into the core.

And those are two cases, as I said, of many more, possibly up to a 100. And the results of all these cases are plotted in something like this.

As I said earlier, the cases that have a very high reactivity insertion rate along here are protected by the high flux trip. And the cases that have slow reactivity insertion rates are protected by the overtemperature delta-T trip. And actually these curves continue. I think they go like this. Okay.

But this plot shows that it was protected through this very wide range of reactivity insertion rates, wider than you might expect during operation by these trips, the overtemperature delta T and the high neutron flux.

And I have more results along those lines. This is at 60 percent power. And then at 10 percent power.

That's the rod withdrawal of power analysis. Any questions on that?

Okay. These DNB ratios, by the way, that you see here are calculated by LOFTRAN, not by VIPRE. And they used that derivative estimation method.

Now the next event, the spurious actuation of safety injection at power is probably the only event in Chapter 15 that actually challenges that criterion that prohibits escalation of a condition II event into a more serious event, at least that's the only one we know of. And the mechanism is that you have a spurious SI signal, a fairly common event, a condition II event and causing the safety injection system to actuate. And in some plants, like Beaver Valley, the safety injection system includes the charging pumps. And the charging pumps are capable of pumping into the RCS at nominal pressure. In fact, their shut off head is at 2600 psi. So they can not only can they pump into the RCS nominal pressure, they can lift safety valves.

If they fill the pressurizer and lift out of the PORVs or the safety valves, then the question is if these valves are not qualified for water relief, the deterministic accident analysis methods assume that such valves once opened would stick open. And that would be a condition III event, a small break LOCA.

Beaver Valley is a little bit unusual compared to other Westinghouse plants. Beaver Valley has three PORVs rather than two.

Another interesting aspect of this accident is that it's misunderstood, it has been misunderstood in terms of its analysis. I've seen analyses in licensing basis that talk about DNB ratio and how DNB ration safety analysis is met. Even some analyses that talk about RCS pressurization or overpressurization. Neither is of concern.

First of all, the safety injection signal will automatically trip the reactor that's in the protection system. The reactor trips immediately. So there's no danger of DNB.

And secondly, since the shut off head of the charging pumps is only 2600 psi, there is no danger of exceeding 110 percent of design pressure.

So those two concerns go away and we're left with the escalation to a condition II event.

So this illustrates how the graphic trip occurs immediately. And we have the core temperature, core average temperature dropping and then eventually coming up to this level here. This is about 563. And basically what this temperature is determined by the secondary side temperature.

The steam generators sitting at about 1100 or 1200 psi perhaps the safety valves are open. Saturation temperature at that pressure is about here.

This is the pressurizer volume, the pressurize fills here. And we see that the cycle to safety valves, we have four openings. And doing the review I questioned the PORVs. Certainly the licensee said, well we don't need the PORVs. We're not going to take credit for the PORVs. We're qualifying the safety valves for water relief. So we'll use the safety valves to mitigate this event as we see here. Safety valves are opening and closing. And they qualify for water relief, so we can expect them to close as designed.

However, the PORVs are going to be there. And the PORVs will open first unless you have them blocked. I don't think that would be very likely. But the PORVs once opened, you have to be sure that they will close.

To qualify PORVs for water relief it takes two steps: (1) the valves themselves have to be qualified for water relief along with the discharge piping, and; (2) the automatic control circuity for the PORVs has to be safety graded. And normally that's not safety graded.

And that's there to guarantee that the PORVs will open when required and will close when required.

In this case since the PORVs are not being credited for mitigation of the event, we need to worry only about the closing. In other words, if the pressurizer fills and pressurized by the charging pumps, it's possible that the PORVs will open. If they open, we need to know that they'll close. If they don't open, then we know that we have the safety valves available. And this is what the transient here shows; that the safety valves will handle this event.

So in response the applicant pointed out the protection grade signal on low pressurizer pressure that will automatically close the PORVs if they should open.

MEMBER SIEBER: On the other hand if the PORV is not tested and qualified to pass water, even though you get a close signal, it may not close, right?

MR. MIRANDA: Yes. The EPRI valve tests were used to qualify the PORVs for water --

MEMBER SIEBER: So they will close?

MR. MIRANDA: They will close if they get a signal.

MEMBER SIEBER: Okay.

MR. MIRANDA: This is the mass flow rate for the safety valves on the four openings.

MEMBER WALLIS: They will close if they get a signal? Don't they sometimes stick?

MR. MIRANDA: Well, for the purpose of the analysis if the valve is qualified under these conditions, if PORV is not only used for steam release; if it's qualified for water relief, we will assume that it operates as designed. Because the valve is qualified for water relief. And it is safety graded, by the way. The PORVs themselves, the components are safety grade. The problem is that the circuitry is not safety graded. There are a couple of single point failure vulnerabilities in the circuitry that need to be corrected. That's for the opening circuitry.

For the closing circuitry that signal comes from the protection system. So there will be a reliable close signal.

MEMBER WALLIS: I thought TMI had a signal that didn't close for mechanical reason. TMI had boron deposits or something that stopped that closing. Hey, you have plenty of signal.

MEMBER MAYNARD: Okay. But for this accident you could have the same situation if a qualified safety relief valve sticks open. Hence, you go into your small break LOCA analysis. For this analysis you're assuming that the valve closes there. It for any reason it did not, you're still covered by your small break LOCA analysis.

CHAIRMAN DENNING: And if you have a monitor that says it didn't close, then you can close a block valve the PORV?

MR. MIRANDA: Yes. Those are practical considerations which are not relevant here.

CHAIRMAN DENNING: In regulatory space you're saying?

MR. MIRANDA: Right. Because here they're concerned about meeting that ANS criteria that says you can't go to a condition III event. So if it sticks open and if you're doing things like closing the block valve, you're mitigating a condition III event. You've already violated the criteria.

This is also important here. This pressurizer water temperature. The EPRI valve tests showed that safety valves and PORVs, but safety valves can be expected to function as designed if the water temperature does not get too cold. For Crosby safety valves which are installed in Beaver Valley Unit 2, the temperature must not go below about 613 degrees.

MEMBER SIEBER: Put them in a box and put a heater in there.

MR. MIRANDA: Excuse me?

MEMBER SIEBER: Put them in a box and put a heater in there, which is what they did.

MR. MIRANDA: And for Beaver Valley Unit 1, which has Target Rock safety valves, they're much better off with the water temperature for those valves has to be above 330 degrees.

So these two plots are fairly important. Eventually if you continue this, you will get below 613 degrees. But we can expect operator action to occur before then. And this is the way the event is mitigated. There's no automatic protection system function such as reactor trip or other function that will mitigate this event. It takes operator action. An operator must shut down the charging pumps. And once that's done, the event is basically over. And that will occur before the temperature reaches 613 degrees.

Westinghouse plants, there's a class of Westinghouse plants in which Beaver Valley is included but Ginna is not which use the charging pumps in the safety injection system. And therefore, are susceptible to this kind of a situation. And there are ways to show that ANSI criteria is met.

One is to show that the operator acts before the pressurizer fills to shut off the charging flow. Another is to qualify the PORVs and to relieve water by qualifying the PORVs themselves and the discharge piping, and correcting the automatic control system's circuitry. And six plants have done that; Diablo Canyon, Callaway, Millstone have done that and Salem also.

And the other option which Beaver Valley has taken is to qualify the safety valves along with taking credit for the closing signal coming from the protection system.

So those are the three transients. Any questions on those?

CHAIRMAN DENNING: Large LOCA lines, too? I didn't see it in the handout.

MR. MIRANDA: No.

CHAIRMAN DENNING: No? So you don't have any large LOCA --

MR. MIRANDA: No, I don't.

CHAIRMAN DENNING: So basically for this part you're done then?

MR. MIRANDA: I'm done, unless you have any questions or you wish to talk about overtemperature delta T or anything else. Do you want to see transients like this for Ginna on Thursday.

CHAIRMAN DENNING: Yes.

MR. MIRANDA: Okay.

CHAIRMAN DENNING: Okay. We're done? Yes.

Okay. Thank you.

MEMBER WALLIS: Let's go back to modern technology now. Note how sharp the last slides were. You could even read the small print on those.

MR. FREDERICK: Again, I'm Ken Frederick. I'm here to talk about the balance of the safety analysis for Beaver Valley.

The last four subject areas we're going to talk about small break LOCA, close LOCA long term cooling and boron precipitation as well as containment, containment conversion program primarily, containment overpressure credit and we'll briefly touch on the dose assessment results.

To start off with small break LOCA. As mentioned earlier, we're using NOTRUMP, which is the current licensing basis for Beaver Valley and Westinghouse approved methodology.

We have made some modifications to the plant in order to retain or regain some of the margin that we're losing for the EPU. The primary change here is the higher head or higher capacity, high head safety injection pumps. The increased flow associated with that modification is around 5 percent.

We're also replacing some instrumentation that gives us lower uncertainties which are factored into how we set up the system, throttling.

We also increased the minimum SI accumulator pressure and that provides some benefit for the small break LOCA analysis.

During the course of the Staff review for the small break analysis several questions were raised for us to address. The first one dealt with the methodology which Westinghouse was using concerning the break spectrum.

Typical practice having to analyze

integer break sizes, for example 2", 3", 4". And the Staff felt that that was too course to capture the maximum PCT.

Another issue which was raised was loop seal clearing assumptions. The approved methodology allowed for loop seal clearing on the broken loop but not the intact loops. And our EPU analysis we had other opinions of that methodology. Had actually credited loop seal clearing on the intact loops as well. So the Staff asked us to address that.

Another request from the staff was that oxidation results for local oxidation needed to include pre-transient oxidation. That's the oxidation which occurs over the normal life of the fuel.

Another issue which was raised here was for some of the smaller small breaks in the analysis these things tend to hang up in terms of the PCT. And primarily that's -- in fact, we reached kind of a stagnation point.

The operators normally have a response within a fairly small time frame. And we see the slides of the PCT curves, we'll maybe talk about this some more. Basically the concern here was that the operator actions needed to be done in a timely manner so that we could demonstrate refill of the core.

DR. BANERJEE: There's lots of little slides that we are missing.

MR. FREDERICK: Pardon me?

DR. BANERJEE: The previous one you had those --

MEMBER SIEBER: He wants to see in that little box.

DR. BANERJEE: Then give us an option.

MR. FREDERICK: This is basically a pictorial explanation of loop seal clearing if you had a question about what that is. Loop seals, of course, are across under leg

CHAIRMAN DENNING: Go ahead. You can proceed.

MR. FREDERICK: So we addressed the Staff questions in this area. We did the analyses. We've looked at break sizes down to quarter inch increments. The allowance for loop seal clearing on the intact loops within the analysis.

We also do -- normally this is always done, but the burnup studies we did for oxidation and that's looking at oxidation over the life of the fuel. And we've included the pre-transient oxidation in that calculation to show that we met with the pre-transient.

This is the spectrum sizes that we've analyzed starting at 2 inch and going all the way up to 6 inch. And in between 2 inches and 3 inches we ran these smaller increments.

You can see there that the case of Unit 1 the peak clad temperature, the highest case ended up being 2.75 inches where previously I think it was 3 inches. And for Unit 2 the worse case is still 3 inches. But, yes, there is a small -- something on the order of for these analyses I think up to 60 degrees. For example 3 inches or 2 3/4 inches.

The other thing to note there as you get into the smaller break sizes you can see that the transients well out here past close to an hour. And the theory there was that we need to take operator actions, which is primarily to pull down, depressurize, which allows the vessel to refill in that time frame.

DR. BANERJEE: Do you get reflux condensation in the steam generators for any of these break sizes?

MR. FREDERICK: Josh from Westinghouse.

MR. HARTZ: Yes, this is Josh Hartz from Westinghouse. I'm in charge of the neutron small break LOCA evaluation model.

Yes, after the single and two phase natural circulation period when that mechanism breaks down, the steam generators go into reflux cooling mode and NOTRUMP does model that.

DR. BANERJEE: And all break sizes or some break sizes and when does natural circulation stop and when did you get into refluxing?

MR. HARTZ: Well, it's going to vary with break size. If you get into larger break sizes, you depressurize so quickly that you lose two phase natural circulation so quickly that the break becomes the dominant means of energy removal. So the reflux condensation aspects tends to increase as break size increases.

DR. BANERJEE: So at 2 inch, say, you'd get refluxing but at 6 inch you wouldn't?

MR. HARTZ: More so than you would in the 6 inch break, that's correct.

DR. BANERJEE: Okay. Now you're going to get more steam flow to the steam generator because your power is greater by 10 percent, roughly, here?

MR. HARTZ: That's correct. Your boil off.

DR. BANERJEE: Now refluxing is effected by flooding at the steam generator tube sheet inlet, right? So can your steam generator inlet flow is roughly the same because it's the same flow area that you have. Does the 10 percent increase in steam flow lead to more water hold up in the steam generators or not?

MR. HARTZ: NOTRUMP does show some liquid hold up in the steam generators, but it doesn't tend to dominate the results too much because we only see it in the smaller breaks. But the --

DR. BANERJEE: Do you get any core level depression due to that?

MR. HARTZ: Due to liquid holdup in the steam generator we have seen it, but that tends to make the results more conservative because the differential pressure is driven up and it tends to drive mixture level down. And sometimes make the break flow stay at a low quality two phase mixture for a longer period of time.

DR. BANERJEE: When you do these reflux calculations, do you get flooding at the inlet of the steam generators due to the steam flow or are you away from flooding? Flooding defined as Graham Wallis would.

MEMBER WALLIS: CCFL.

DR. BANERJEE: CCFL.

MR. HARTZ: The mechanism that we've seen for these, and in some cases we have seen some flooding, but again it was for smaller breaks and that mechanism tends to break down rather quickly. And so it doesn't tend to have much dominance on the transient.

DR. BANERJEE: Well, I'd be interested to see the difference in this due to the increased steam flow rates as to whether you get a more extended period of flooding or not compared to pre-EPU as opposed to post-EPU conditions. Because you're getting 10 percent more flow rate, right? Now whether this is giving you a larger period of flooding or not is interesting for me to know.

So you take the 2 inch break, it doesn't really matter.

MR. HARTZ: Okay.

DR. BANERJEE: Okay. Because you say flooding breaks down quickly. It would only break down if the core level went down somewhat so your steam generation rate went down or because you're getting the same stuff out of the break anyway, right,in rough terms?

MR. HARTZ: That's correct, yes.

DR. BANERJEE: At these conditions. So whatever goes to the steam generator is coming from the core. So you're getting 10 percent more the core. So you would expect you'd get a more extended period of flooding and more liquid hold up in the steam generators and a larger core level depression. So I'd like to see how -- just if we do this by hand, you can more or less work it out using Graham's flooding criteria CCFL to see whether this is in correspondence with what you would expect by a hand calculation or not.

MR. HARTZ: Well, one thing I might add is there were some air water tests done with the steam generator inlet plenum that were performed very early on in NOTRUMP's development. And the model would be based on that data. And what we could do is take a look and see how the EPU would impact that.

DR. BANERJEE: Right. But there was periods of this that occurred in Semiscale as well, if I remember. So presumably NOTRUMP has been sort of validated against those data as well?

MR. HARTZ: Yes, we used Semiscale as part of our validation package.

DR. BANERJEE: So you've got some high pressure validation data, too, right?

MR. HARTZ: That's correct.

DR. BANERJEE: Hopefully. So anyway, it's worth finding out. Because one of the key aspects of this higher steam generation rate is the potential for more liquid hold up. I'm not saying it would happen here. It depends on the flow area of the steam generator, all these things, obviously. So we take a look at this aspect.

Thanks.

MR. HARTZ: Okay.

DR. BANERJEE: How many tubes are plugged, you know, all this.

MR. HARTZ: Well, we assume different plugging levels for each unit because Unit 1 has the newer generators. Obviously, there would be less tube plugging involved.

I believe Unit 1 assumed 10 percent and Unit 2 22 percent.

DR. BANERJEE: Okay.

MR. FREDERICK: Let's go to the next backup slide.

This is a plot which shows the transient oxidation which is calculated over the burn up life of the fuel, the red line. The green line is a representation of a pre-transient type oxidation. Normally that would go to zero at zero burn up. However, this is cut off here at conservatively at about 4 percent.

And blue line is the addition of those two.

So we show that over the life of the fuel, 17 percent criteria including pretransient oxidation.

MEMBER WALLIS: There's that much pretransient oxidation? Yes, there is.

MR. FREDERICK: Yes. Essentially that number corresponds to a fuel design limit. Now, typically the actual does not approach that limit and it's probably 50 to 75 percent of that. But it does represent an upper bound that we use in the fuel design.

Next slide, please.

This shows the results for the EPU analysis as well as the current small break LOCA analysis. You see here all the acceptance criteria are met plus some 2200 for PCT and the hydrogen are below the respective limits.

And this analysis reflects the modifications we made to increase SI flow as well as the accumulator pressure. So those changes tend to offset the effects of EPU.

MR. HARTZ: Dr. Wallis, in case you're wondering, those maximum hydrogen generation rates, we just look at the hot assembly average. And if it's less than 1 percent, that's what we declare. But in reality, as you know, not all the assemblies operate at that power. So if you were to do an actual rod census, it would be something much less than that.

MR. FREDERICK: No more questions on small break. We're move on to post-LOCA long term cooling. And this is the analysis that we do to demonstrate that we do not reach precipitation limits for boron in the core following a LOCA. And another criteria for this analysis is that we show that we have enough flow to meet the boron off and the flushing requirements.

CHAIRMAN DENNING: And what did you have as the backup on this one. Because I'm definitely interested in some particular. What's your backup say?

MR. FREDERICK: This backup just shows the alignment, the system type alignment for hot leg recirculation.

CHAIRMAN DENNING: Okay. We may come back to it. So go forward.

DR. BANERJEE: So you switched to hot leg?

MR. FREDERICK: On Unit 1 we switched to a simultaneous hot and cold leg injection.

Again, as part of the NRC review we had

some questions in this area. Some of these were associate with I think some issues that came up from Waterford. There were issues that we were asked to address for this particular analysis, the first one being core voiding must be part of the calculation for the boron build up. There's some effects such as low pressure drops are needed to be included.

If we were using a boric acid solubility limit higher than base do pure water and boron or elevated temperatures, then we needed to justify that.

And the Appendix K decay heat was the used analysis.

So, again, in this case we redid the calculations taking into consideration these issues.

CHAIRMAN DENNING: Now you're going to have to help me because -- maybe it'll be clear on the next. I'll wait before I ask some more questions.

MR. FREDERICK: So for the core voiding aspect of this, we did more voiding calculations on a transient basis using a modified Yeh Correlation.

CHAIRMAN DENNING: Now I don't understand that. What does that mean, Yeh? You're using what kind of analysis to determine what's happening within the core and --

MEMBER WALLIS: Some sort of heat flux or something or it's a -- isn't that the same thing. It's how you calculate the void fraction.

MR. FREDERICK: I'll ask --

MR. FINK: My name is David Fink. I work for Westinghouse.

Dr. Wallis, that's correct it's kind of a drift flux. It's a way just to calculate the voiding.

MEMBER WALLIS: I think it's actually benchmarked against the rod bundles and things. Real Geometry is like this, so --

MR. FINK: I believe it is.

CHAIRMAN DENNING: Okay. Now tell me again. The vehicle that's doing the analysis, how is it modeling the system?

MR. FREDERICK: It's a fairly simplistic analysis. Essentially you're looking at the core and then the boil off rate and the --

CHAIRMAN DENNING: So it's the equivalent of a RELAP analysis where you would look in -- and why not? I'm missing how you're going to determine -- I'm concerned about the way volumes are mixed under the assumption of when the boron concentrates and you get increased density there, it's not clear to me that you're adequately considering what's really happening axially up the channel and whether as you get more and more bubble formation within the channel, whether that's offsetting the increased density due to concentration of boron. Can you give me a better idea as to how you're actually analyzing the flow characteristics of what's happening in the core.

MR. FREDERICK: Dave, do you want to take that?

MR. FINK: Yes. This is David Fink again.

If I could take a minute here and just explain. The original analysis that we did for the Beaver Valley EPU actually in the time line was several years ago. So they were actually pre-Waterford uprate. Okay. Those analyses used a simple control volume calculation and much as we've done for 25, 30 years for hot leg switch over calculations.

And in those simplified control volume, you have a boiling pot, you have steam coming out, you have borated water going in and you build up boric acid in the core region. Okay.

So for the uprate the difference is more power, more boil off, faster build up. Okay.

In that very simplified approach there were two big conservatism at least as we believe it. And the first was how we selected the control volume. Okay. The control volume that's historically been used didn't include any of the lower plenum. It didn't include any of the volume --

MEMBER WALLIS: Uniform mixing in this whole control volume? Surely when you have boiling in a channel the boron is sort of pumped along and then as the steam evolves, the boron's left behind. So it concentrates at the top, doesn't it?

MR. FINK: Well, our simplified model assumed complete mixing in the core region.

MEMBER WALLIS: There's some experiments that show that's reasonable?

MR. FINK: Well, we believe there's quite a bit of circulation going on in the core region. For example --

CHAIRMAN DENNING: Why do you believe that? Why do you believe that? That's what I want to know.

MR. FINK: Well, we've looked at our large break LOCA WCOBRA/TRAC code and we've looked at what happens in the core region in that code.

CHAIRMAN DENNING: Now, which specific accident is the one of concern here?

MR. FINK: This is all large break.

CHAIRMAN DENNING: Large break?

MR. FINK: Yes, sir.

CHAIRMAN DENNING: Okay. So that you have essentially atmospheric conditions at the outlet, is that true?

MR. FINK: Yes, sir.

CHAIRMAN DENNING: Okay. And you have a big level swell kind of situation in terms of the voiding -- as you get near the upper part, there's a bigger and bigger froth.

MR. FINK: Okay. Well, I can just continue here.

CHAIRMAN DENNING: Yes.

MR. FINK: So that was what we originally did for the first go around.

MEMBER WALLIS: Dry regions? If you have dry regions presumably the boron's left behind on the wall.

DR. BANERJEE: If there was core uncovery.

MEMBER WALLIS: Right. Or you had spattering, a spattering of cooling and you have spattering cooling rather than froth cooling, but the boron's left behind on the wall.

CHAIRMAN DENNING: If you'd like to use that board over there to illustration, you can also do that. If that would help.

DR. BANERJEE: Back to that screen.

CHAIRMAN DENNING: But not the screen.

MR. FINK: I might do that.

So in response to NRC RAIs, and this was largely I guess posed Waterford fallout and specific RAIs asked by the Staff for these calculations, we did this work. Okay. And we addressed the four things that are listed up on the board, most significantly was the use of Appendix K decay heat, which these calculations have always been based on a best estimate decay heat. And so we used Appendix K decay heat. We also calculated a time based core voiding. And all that does is that reduces the liquid volume in your control volume. Okay.

So we did those calculations. Because we are now taking a lot of liquid volume out of the core region we choose to credit some volumes that were not previously credited, and probably the most significant is the one that was discussed during the Waterford EPU, which is the lower plenum.

MEMBER WALLIS: There's an experiment. I'm trying to remember the name of it, isn't there?

MR. FINK: It was the MHI BACCHUS Test.

MEMBER WALLIS: BACCHUS. It was a god of some sort. BACCHUS. This seemed to show that things really were mixed?

MR. FINK: Yes. Yes, it did.

MEMBER WALLIS: Surprising to us.

MR. FINK: It clearly showed --

DR. BANERJEE: Yes, it is surprising. Can you explain that test again.

MR. FINK: Well, the test clearly showed the point at which the denser higher concentrated region up in the core becomes dense enough to displace the less concentrated volume in the lower plenum. So in the test you could clearly see as the --

MEMBER WALLIS: Heavy concentrate --

DR. BANERJEE: I mean isn't there a countervailing flow which is balancing that?

MR. FINK: Well, under this scenario this is a cold leg break where all your excess SI flows out the break. So more SI doesn't help you. You basically have a stagnant boiling pot and you're feeing through the lower plenum enough to make up boil off, but --

DR. BANERJEE: And that's not enough for the density head being developed? It allows you to settle the borated water against that flow?

MR. FINK: Well, the flow that's coming in is coming from the sump and it's coming --

MEMBER WALLIS: In the BACCHUS report?

DR. BANERJEE: Who did these experiments?

MR. FINK: MHI.

DR. BANERJEE: Who is that?

MR. FINK: Mitsubishi Heavy Industries.

DR. BANERJEE: And these were done where in --

MR. FINK: These were done in a scale facility they did specifically to look at this. Because Japanese plants to this day still use a 24 hour switchover time, which was the original Westinghouse design.

MEMBER WALLIS: So it's a big facility, as I recall. It was scale, but it was still fairly big?

MR. FINK: Yes. It was a slab model, so it was like full length, 180th scale, I believe.

DR. BANERJEE: And so they had borated water boiling off on heaters or something?

MR. FINK: Correct.

DR. BANERJEE: And they had a lower plenum markup and they looked at the density profile?

MR. FINK: Well, they had it highly instrumented with boron sensors and temperature sensors. And we wrote a summary report that was presented for the Waterford EPU. And I'm sure the NRC has a copy of it. It's very interesting.

DR. BANERJEE: But do you have a copy of the BACCHUS report itself?

MR. FINK: It's a MHI test, so we wrote a summary report that is part of --

MEMBER WALLIS: Right. I saw it. I think it was in the Waterford context. We spent some time on this.

MR. FINK: Yes.

DR. BANERJEE: So your contention is that the whole thing is well mixed, not just the core.

MEMBER WALLIS: So what's your point? But once you get enough density difference it turns over, doesn't it?

MR. FINK: That's correct. And we'd like to credit the whole lower plenum to give us a little better answer, but we conservatively credited as was done for Waterford. We just credited 50 percent of the lower plenum as being a reasonably conservative approach.

DR. BANERJEE: What happens if you don't credit it?

MR. FINK: Well, it's just how much liquid volume you have in your calculations. So you have --

DR. BANERJEE: Right. So suppose you just stayed with your old assumption of allowing mixing in the core region and nowhere else?

MR. FINK: Well, then the boric acid would build up faster.

MEMBER WALLIS: I guess we had a lot of questions previously about whether just looking at solubility limits was good enough when you're boiling off this -- when it gets concentrated the boron, presumably, can precipitate around nucleation sites and things like that. It's not as if just solubility alone is governing whether or not you get some precipitation. And if you have some drop wise cooling, then if a drop evaporates it leaves behind its boron. So we had questions of that type. I don't know if they were ever answered. Because you just look at the overall solubility, don't you?

MR. FINK: That's correct.

MEMBER WALLIS: I think we asked the Staff to look into this, didn't we, Ralph?

MR. CARUSO: Yes. And they presented.

MEMBER WALLIS: Yes, then we were satisfied. We spent some time on it, I know.

DR. BANERJEE: So are we revisiting something that was --

MEMBER WALLIS: Yes, we went into it. We spent a whole day or something like this.

DR. BANERJEE: Done.

MR. CARUSO: Yes.

MEMBER WALLIS: But you should get the BACCHUS report.

DR. BANERJEE: All right.

MEMBER WALLIS: It's all about Roman orgies and things like that.

DR. BANERJEE: It sounds like it.

MEMBER WALLIS: It's a good report. You should get it. It could tell you some things that wouldn't be intuitive if you just thought about it.

CHAIRMAN DENNING: I'd like some information on the third bullet on --

MR. KELLERMAN: Yes. My name is Brett Kellerman. I'm with Westinghouse. And we can get access to a summary report of the BACCHUS test that we brought for the Waterford --

MEMBER WALLIS: We probably have that in the record somewhere. The Waterford record, we have it. You can just pull it out and give it to him.

CHAIRMAN DENNING: But you do it, like in the third bullet there, you do have some information on sump additives as they effect boric acid solubility, is that what I'm seeing there?

MR. FREDERICK: Yes. Similar to what

Waterford had at I believe their TSP plant.

MR. FINK: Yes. This is Dave Fink again.

In these analyses we do not credit any elevated solubility limit due to sump additives for this uprate.

MEMBER WALLIS: Additives are presumably chemicals?

MR. FINK: Yes.

MEMBER WALLIS: They're not fibers?

MR. FINK: I hope not.

DR. BANERJEE: There's also a possibility that it wouldn't mix because there'll be enough fiber at the core inlet, right?

MEMBER WALLIS: Well, that's another question. Yes.

MR. FREDERICK: We did a test using sodium hydroxide and we found that the precipitation limit increased from 29 percent up to about 48 percent. But we are not crediting that as part of our analyses. And we did use decay heat.

MEMBER WALLIS: It should be part of the sump question, though, when you get fines going through the screens. Would that make any difference to his picture?

MR. FREDERICK: Yes. That's something that

I believe is going to be addressed as part of the downstream --

MEMBER WALLIS: Under GSI-191.

MEMBER WALLIS: -- effects under GSI-191. Yes.

DR. BANERJEE: Suppose that it didn't mix outside the core region, for whatever reason, it could be that the core inlet is blocked with debris --

CHAIRMAN DENNING: The problem may be worse than that if that happens.

DR. BANERJEE: Well, there's some bypass paths through the --

MEMBER WALLIS: The sump?

DR. BANERJEE: Yes. So then what happens to the boron if it's boiling off happily in the core without this assumption of mixing with the lower plenum? Is it then an untenable --

MR. FINK: Yes. You'd have a precipitation limit much sooner and --

DR. BANERJEE: Yes. Is it an untenable situation then or is it still okay? Do you have to make this assumption or do you not to make it liveable?

MR. FREDERICK: Well, if we ended up with a shorter time, say 3 hours or 4 hours or something, not necessarily --

DR. BANERJEE: Is that still okay?

MR. FREDERICK: --untenable but we would have to look at what our makeup rates could be. So we did a test here as we need enough flow to meet the boil off and also flush the core.

DR. BANERJEE: Because if I remember the report that was circulated by Ralph, you have 6 hours to do the switchover, is that right?

MR. FREDERICK: That's correct.

DR. BANERJEE: Yes. So at the moment if you didn't credit half the lower plenum, which is a large volume, and only had the core, would this be like 2 hours, 1 hour, 3 hours? What would be that number?

MR. FREDERICK: Do you have a feel for that, Dave?

DR. BANERJEE: Because the volume is very different, right?

MEMBER SIEBER: Yes.

MR. FINK: This is Dave Fink.

The lower plenum's actually a pretty good size volume, but because we're crediting half of it, it probably represents maybe one-fourth -- maybe one-third, one fourth of the total volume. So it would --

MEMBER WALLIS: So it would feed or something in total --

MR. FINK: Correct.

MEMBER WALLIS: And the core --

MR. FINK: So is representing a third of the volume you'd increase.

DR. BANERJEE: Well, what is the core volume that you're crediting?

MR. FINK: I believe with the one-half lower plenum volume and the core voiding, we're probably -- I'd say approximately 900 cubic feet.

DR. BANERJEE: And of that about 300 is lower plenum?

MEMBER WALLIS: Half of it. Half of it.

DR. BANERJEE: Half of it.

MEMBER WALLIS: A 150.

MR. FINK: I'd say that's --

DR. BANERJEE: So the core volume is so large.

MEMBER WALLIS: Don't get it all because there are voids in it.

DR. BANERJEE: I see.

MR. FINK: Well, it's core and upper plenum, so it's --

DR. BANERJEE: Well, why the upper plenum if it's boiling off. Wouldn't that get full of steam or something?

MR. FINK: Well, we look at the way this calculation is done, we do the voiding at the top of the core at the core exit. And we apply that voiding up through the upper plenum. So the upper plenum does contribute.

DR. BANERJEE: But the upper plenum is not empty in this case?

MR. FINK: That's correct.

DR. BANERJEE: So the steam is going out through the hot leg, is that right?

MR. FINK: Correct.

DR. BANERJEE: Eventually it makes its way out to the cold leg break somehow, around the circuit?

MR. FINK: Correct.

DR. BANERJEE: So why is the upper plenum not full of steam?

MR. FINK: The upper plenum would be full of some mixture, some voided --

MEMBER WALLIS: Otherwise you can't drive the water along the hot leg, presumably.

DR. BANERJEE: There's no water going on--

MEMBER WALLIS: Right. You dry out --

DR. BANERJEE: It's mainly steam, right?

It's mainly steam going along?

MEMBER WALLIS: Yes, but --

DR. BANERJEE: Maybe a sketch would help because I'm sort of a bit lost as to where all the water is in this system. So can you just sketch it?

MR. FINK: Ken, do we have a backup slide that might have that?

DR. BANERJEE: I mean the simple control volume approach is great, but we got to put the water in the right places here.

MR. FINK: Well, we don't credit anything outside of the vessel, outside of the inside of the core barrel actually in this calculation. So we don't credit any of the volume in the former region or the downcomer.

MEMBER SIEBER: Or that?

MR. FINK: No, no.

MEMBER SIEBER: That's a significant amount of water.

MR. FINK: Yes, sir.

DR. BANERJEE: Yes. Show us what you're crediting --

MEMBER WALLIS: Here are the levels down below the hot leg.

DR. BANERJEE: That's what I thought it

would be, but for some reason you have a volume of mixing above.

MR. FINK: Well, in that picture everything we're crediting is right inside that inside cylinder that represents the core. So we don't crediting anything outside of that.

MEMBER WALLIS: Credit the downcomer at all?

MR. FINK: Correct.

DR. BANERJEE: Okay. So how much is that volume that you would credit if you didn't credit any piece of the lower plenum here?

MR. FINK: Up to the bottom of the hot leg, I believe it would be 1,000 cubic feet.

MEMBER WALLIS: With the bubbles or not?

MR. FINK: That would be total volume.

DR. BANERJEE: Only the core?

MR. FINK: Correct.

DR. BANERJEE: Okay. And then if you credited 50 percent of the lower plenum, it's another 300.

MEMBER WALLIS: One fifty.

MR. FINK: Approximately.

DR. BANERJEE: One fifty. Okay. So it's not such a big deal.

MR. FINK: It's actually a little more than 150, I believe.

DR. BANERJEE: All right. I think that's fine. If that -- that sounds good.

MEMBER WALLIS: Well, I think the thing is when you're so close to the limit, you've got to darn sure that it's well mixed. Because all you need is to have a little bit of nonmixing and you have twice as much concentration in the top as in the bottom and you get precipitation. So you really have to study the BACCHUS report to be convinced that there's good mixing.

MR. FINK: There are some other conservatism in the methodology. For example, we don't credit any entrainment around the loops that might take place early on where you'd expect to carry a lot of water around the loops. So we start our problem from the beginning. And that probably represents a great deal of conservatism.

We've always had trouble identifying exactly how much entrainment you'd get around the loops.

CHAIRMAN DENNING: Do you know offhand what the void fraction is in the upper plenum that you're talking about? What's the void fraction?

MR. FINK: Probably I'm guessing 70 percent.

CHAIRMAN DENNING: Seventy percent?

MR. FINK: Seven percent.

CHAIRMAN DENNING: Even though there's that much void fraction, the density of that material is higher than the density of the material than the cold water in the lower plenum?

MR. FINK: It would be the density of the liquid, and you'd have to as you went down into the core and into the periphery is where you'd be much less voiding.

MR. FREDERICK: This slide actually shows the collapsed liquid load that was calculated.

DR. BANERJEE: Where's the bottom of the core?

MR. FINK: The 12 foot level there is the top of the core. So that's collapsed liquid level.

DR. BANERJEE: Right. But where is the bottom of the core?

MR. FINK: Zero.

DR. BANERJEE: Zero? All right.

MEMBER WALLIS: At some previous time this was dried out on top?

DR. BANERJEE: At zero -- time zero.

CHAIRMAN DENNING: Right. This is much later. Sometime it was dried out.

DR. BANERJEE: Early times.

MEMBER WALLIS: And when it was dried out didn't you get boron precipitation on the dried out part?

DR. BANERJEE: That was the large break LOCA.

MEMBER WALLIS: Yes, but you get it in the small break, too, otherwise you never get these high temperatures. Well, they get boron pleating on these tubes. But anyway Staff convinced us that we're not to worry about it I think before.

MR. FREDERICK: Go back one slide.

MEMBER WALLIS: Move on probably.

CHAIRMAN DENNING: Yes. Right. Let's move on. I think some of us are going to want to look at that BACCHUS report again today.

MEMBER WALLIS: Because it's a very interesting subject.

MR. FREDERICK: In the draft SER there was an item identified as a contingency for this particular analysis. And it has some discussions with the Staff about that issue. It's described here, and basically the concern was that for smaller breaks we need to demonstrate the capability that we'll be able to cool down before the precipitation time in order to be able to -- the actual injection on the hot legs. An we've had some discussions with the Staff on that issue. And Dr. Ward will be talking about that later. At this point we're convinced we have a --

CHAIRMAN DENNING: I guess I'm a little bit confused about the difference between large LOCA case and then the small LOCA cases that you were talking about as far as what the conditions are that could lead to precipitation and can you help me there?

MR. FREDERICK: Well, I think for small breaks typically and your temperature and your pressure is going to hang up. So precipitation limits are very high under those conditions. The concern would be that borrowing that scenario who hold on the pressurization mode, want to make sure that you get to the cooled down condition before you reach precipitation limit for the cold condition. That, again, is a function of the operator response to the event.

DR. BANERJEE: Because if you inject in the hot leg, you get cold water into the core, right? Is that the concern?

MR. FREDERICK: That's not the major

concern. The major concern is depressurizing enough so we get hot leg flow. Because for Unit 1, anyway, we're aligning the low head pumps to the hot legs and it would have a shot off pressure of around --

MEMBER WALLIS: Once you get hot leg flow, you just flush the boron out.

DR. BANERJEE: Yes.

MR. FREDERICK: Again, Dr. Ward will be discussing --

MEMBER WALLIS: Now you need to keep enough boron in to avoid criticality concern? And you've already scrammed the reactor --

DR. BANERJEE: Well, the water's is borated, isn't it?

MEMBER WALLIS: Yes. Don't you need still boron for the criticality.

DR. BANERJEE: In the injection --

MEMBER SIEBER: The injection water is refueling water.

MR. FREDERICK: So again, we have addressed the questions that were raised by the Staff for this analysis and the results showed for Unit 1 6½ hours is the required switchover time, 6 hours for Unit 2.

In our procedures we actually make

preparations to do that realignment an hour ahead of time. The actually alignment is only a matter --

MEMBER WALLIS: This time depend on the break size?

MEMBER SIEBER: It should.

MR. FREDERICK: Essentially no, because at the point where we're starting the calculations you're fixed in terms of the volume of water in the --

DR. BANERJEE: Well, in long term cooling, which is within an hour --

MEMBER WALLIS: -- off to atmospheric without any break size contributing.

MR. FREDERICK: Yes, heat boil off at that point.

MEMBER WALLIS: At the point of water boiling, essentially an open top.

CHAIRMAN DENNING: But it's still pressurized.

MR. FREDERICK: Large break, it's not in the small break.

CHAIRMAN DENNING: Right. But in the small break it is.

MEMBER WALLIS: Well then how much is pressurized must depend on the break size?

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: And so the time surely depends on the break size, doesn't it?

MR. FREDERICK: David?

MR. FINK: This is David Fink again.

The effect of some pressure assumption in the vessel really helps you in the voiding. So at higher pressures you get a lot of this voiding --

MEMBER WALLIS: You have more water there.

MR. FINK: A lot more water.

MEMBER WALLIS: So there's nothing magic about 5 hours, is there? I mean sometimes it depends on the break size. So what it is the operator measures so that he knows he has to do something?

MR. FREDERICK: From the start of the event.

MEMBER WALLIS: But he doesn't know the break size, so he doesn't really know --

MR. FREDERICK: Yes. The time that we're calculating it represents the bounding case.

CHAIRMAN DENNING: The bounding case?

DR. BANERJEE: Doesn't he have some indicator to know when it would be prudent to switchover? Like isn't there a measurement of some sort that --

MR. DURKOSH: I'm going to try to answer

that. This is Don Durkosh from FirstEnergy.

The emergency operating procedures are based on the limiting large break LOCA switchover time. We do not have any other measurements. We basically will follow our EOP network and we'll be in our E1 procedure waiting for this switchover time to occur, and then we'll be preparing for it. And we'll initiate switchover. So there is no other measurements. In theory, we don't know where the break size is so we set it up for the most limiting conditions there.

MEMBER WALLIS: If it were smaller, he would have longer time?

DR. BANERJEE: So there are no criteria which requires switchover?

MR. FREDERICK: They're all the type criteria --

DR. BANERJEE: No, no, no. Physical criteria.

MEMBER WALLIS: There's not a measurement that you compare with some other measurement --

DR. BANERJEE: Now I'd better switch because things are getting bad or something.

MEMBER WALLIS: No. He's just told within so many hours to do it.

MR. FREDERICK: There's no way to measure the boron --

MEMBER WALLIS: He has to remember?

DR. BANERJEE: Really of the neutron flux, right, in the core? You still have some sort of a flux measurement, right, something?

MR. FREDERICK: Yes. I guess if the source range was operational still, yes, we would have some indication. I'm not sure how you would correlate that to boron levels, though.

DR. BANERJEE: So you don't have a measure of boron? So you have no measure of boron in the core basically?

MR. FREDERICK: Dave, did you have something?

MR. FINK: This is Dave Fink.

Actually, they don't do it but you could in theory measure the boron by the boron concentration in the sump because all the boron that you're leaving behind in the vessel is coming from somewhere. And that somewhere is the sump. So as the vessel concentration's building up, the sump is diluting. So theoretically you could --

DR. BANERJEE: But is the sump so large in volume that dilution would be relatively small compared to the --

MEMBER SIEBER: It would not look the same as the core condition from a chemistry standpoint. Concentrating mechanisms in the core, the sump has everything else.

DR. BANERJEE: Right.

MEMBER SIEBER: And so the concentrations would be different.

DR. BANERJEE: Would be not -- yes.

MEMBER SIEBER: Does -- help you at all in knowing where you're at?

MEMBER WALLIS: At levels lower in the core?

MEMBER SIEBER: Yes.

MR. DURKOSH: This is Don Durkosh again.

MEMBER WALLIS: EOPs don't speak to that.

MR. DURKOSH: Yes. The switchover time is institutionalized in the EOPs. They're consistent for all Westinghouse plants. And this is the approach that we've been using since literally day one. We use these times as the time to go ahead and initiate switchover to hot leg recirc.

DR. BANERJEE: It could be too early, it could be too late; we don't know. There's no way to know.

MEMBER SIEBER: Well, it's based on the analyses.

DR. BANERJEE: On calculations, right? Who knows what these calculations mean, how good they are.

MEMBER WALLIS: But it's been done since day one.

MEMBER SIEBER: The calculations were done by the Westinghouse owners group at the time that the guidelines were done.

DR. BANERJEE: Therefore they must be good?

CHAIRMAN DENNING: So this is how it's changed by the EPU?

MEMBER SIEBER: That was back in 1981 or '82.

MR. FREDERICK: If you consider the calculations bounding and very conservative, as this slide shows you here, we actually ran cases with more realistic assumptions. And you can see trying to get to the limit, which is 29 percent here. Well, you can't actually see it. But considerable difference when you consider better estimate type assumptions. And, Dave, maybe you can --

MEMBER WALLIS: More significant perhaps

is the effect of EPU on this?

MR. FREDERICK: No, this is just --

MEMBER WALLIS: No. More significant would be to show the effect of EPU?

MR. FREDERICK: Well, the EPU ended up reducing the time from 8 hours to 6½.

MEMBER WALLIS: Yes.

MEMBER SIEBER: And that's basically due to the increased decay heat.

MEMBER WALLIS: Yes. But you assume that's not critical? I mean, it's still got an awful long time.

MR. FREDERICK: Yes. Again, it's not challenging the operators to get it done. So the more meaty concern with shortening that time is that the higher you go up on the decay heat curve, the more flow you need. And --

MEMBER WALLIS: There's some sort of alarm clock that starts when there's a break and then after 6 hours says you'd better switchover injection or is he supposed to keep track of all the time?

MEMBER SIEBER: You have blogs.

CHAIRMAN DENNING: That's a good EOP question, I think.

MR. FREDERICK: Yes.

MR. DURKOSH: This is Don Durkosh again.

The operating crew would keep track of what time the reactor trip and we'd have the technical support center available to us, we have our STAs available to us. So we have multiple people basically keeping track. And we have an explicit step in our E1 emergency procedure. We would transition back into our E1 procedure and we'd basically, the next step would be when you approach the hot leg switchover time, begin making your preparations.

So we have various people that would tab of that time.

MEMBER WALLIS: It still would be good if you had something that alerted him. I mean, if I have to cook something, I don't really look at my watch all the time. I like to have a timer that tells me when to switch things off or take them out of the oven. But this is an EOP question.

I think the more you can take away from the operator having to remember things, the better. You have something which actually tells him he's got to do something.

But anyway, it's not really --

CHAIRMAN DENNING: I think we're ready to move out of that into containment analysis.

MEMBER WALLIS: Yes, I think -- yes.

MR. DURKOSH: This is Don Durkosh.

We do have timers in the control room

MEMBER WALLIS: You do?

MR. DURKOSH: But unlike cooking, we do also have a lot of people available to us.

MEMBER WALLIS: Too cooks --

MR. FREDERICK: Too many cooks in the kitchen.

MEMBER SIEBER: You have to remember to turn the timers over.

CHAIRMAN DENNING: Go ahead and continue.

MR. FREDERICK: Okay. I'm going to move on to containment analysis. Again, the containment analysis was submitted actually a little earlier than EPU in june of 2004, and that was approved in February of this year.

And it was a conversion, which mean we went from a sub-atmospheric design to an atmospheric. The difference there being that in the atmospheric design there's no requirement to contain or to get back to sub-atmospheric conditions post accident, which we had previous to the change.

The primary effect of EPU, which was factored into this containment conversion program, was the M&Es from the primary system and the steamline break. Those are really the things that are directly affected by the increase in power.

The mass and energy release calculations for this program use the Westinghouse approved methodologies, and that wasn't a change.

For the containment integrity, part of the calculations, we utilized MAAP-DBA, which is a modification to MAAP 4 which changed some of the containment calculations.

It's similar to the other codes which have been used or approved for applications such as GOTHIC, COCO.

The program the containment uses traditional heat transfer correlations such as Tagami and Uchida. That's consistent with other applications.

For the NPSH calculations we've incorporated a multi node model. And that allows us to get better details on where water is held up in containment and certain volumes. At the box area you can jus see the nodal model that we used. Eighteen nodes.

For small break analyses, and we've done a much more extensive look at small break primarily for sump inventory questions. For that analyses the mass and energy releases were calculated using MAAP. And those results were benchmarked against the code primarily.

The actual operating containment pressure will still be slightly sub-atmospheric at the site 14.3 approximately is atmospheric pressure. And our operating range will be 12.8 to 14.2 absolute.

The older operating pressure, which is actually an air partial pressure limit, was about 4 pounds lower. So at these higher pressures we eliminate the need for applied air when we do make entries, which is a very nice benefits in terms of personnel safety.

MEMBER SIEBER: Well, and you have decompression in the airlock, which is a time consumer and hard on some people, hard on your ears.

MR. FREDERICK: As part of this analysis we've also credited the various modifications which are beneficial. Replacement steam generators for Unit 1, for example. These generators have the restriction nozzle in the outlet where our old ones did not. So we're looking at 4.6 square foot main steamline break versus a 1.4 square feet. So that is a big benefit for the steamline break analysis.

Also the feed isolation and the cavitating venturies, again, limit the mass energy release during a steamline break.

MEMBER MAYNARD: Are those new valves or just new actuators or --

MR. FREDERICK: They're brand new valves and actuators.

MEMBER MAYNARD: Okay. Are they replacing existing valves that are there or --

MR. FREDERICK: There was an existing valve there. I believe we turned that into a check valve, is that right?

MR. TESTA: Yes. This is Mike Testa, Beaver Valley.

Yes, like Ken was saying, we had a check valve in the system that had a motor on it. And what we ended up doing was we restored that to just a normal or simple check valve. And then in the piping system we added a brand new feed isolation valve. New valve, new actuator controls.

MEMBER SIEBER: It is hydraulic or electric or --

MR. TESTA: Hydraulic. Yes.

MR. FREDERICK: We've also added a cord from the reactor cavity so there's the general basement area that allows the water that normally hold up in that cavity to drain back into the sump, which helps out with our inventory issues.

This QS cutback was a feature that we used to extend the spray at Unit 1 that helped us maintain some of the spurious condition. We don't need that any longer so we're eliminating it.

And again, the setpoint for transfer to recirc was lowered under this program and that gives us a little higher sump level at recirc, which helps out with the NPSH.

For the analysis, essentially acceptance criteria that we look at:

Peak pressure, of course, less than the design, which is 45.

Containment pressure reduction of 50 percent, that's essentially an assumption that's made in the offsite dose analysis so we need to demonstrate that we can met that;

NPSH. We need the required NPSH for the pumps which takes suction out of the sump, and;

When the pumps start we look at minimum pump inventory to make sure we don't have any vortexing issues.

MEMBER WALLIS: Of course, that's all

assuming that the screens don't have too much deposited on them?

MR. FREDERICK: Correct.

MEMBER WALLIS: What kind of insulation do you have on this?

MR. FREDERICK: Insulation?

MEMBER WALLIS: Yes. Kind of insulation? Do you have fiberglass or --

CHAIRMAN DENNING: That's the physics.

MEMBER WALLIS: But I wasn't here. I wasn't here. I'm sorry.

CHAIRMAN DENNING: If you could give a little summary.

MEMBER SIEBER: It's reflective.

MR. FREDERICK: But I know and then Mark can maybe jump in. We do have RMI reflective on many of the components. We do have CALSIL.

MEMBER WALLIS: You have CALSIL?

MR. FREDERICK: Yes. We have CALSIL and we have something Min-K, which I -- it's a fiber.

MR. MANOLERAS: This is Mark Manoleras.

We have very small quantities of that material. We're going to target that for removal, that material for removal.

DR. BANERJEE: That's the only fibrous

material? Is that the only fibrous material?

MR. MANOLERAS: That would be our predominant fibrous material.

DR. BANERJEE: And do you have aluminum as well?

MR. MANOLERAS: Yes, we do. Yes, we do. And we actually have a program which takes a look and monitors and maintains the quantities of aluminum in containment. We know exactly what we have. Zinc and aluminum in containment.

MEMBER WALLIS: You have TSP in the sump?

MR. MANOLERAS: No, we do not.

MR. FREDERICK: Carbon hydroxide.

MEMBER WALLIS: Carbon hydroxide.

MR. MANOLERAS: Correct.

DR. BANERJEE: Carbon hydroxide and aluminum is --

MEMBER WALLIS: Yes.

CHAIRMAN DENNING: You can continue. Thanks.

MEMBER WALLIS: Yes.

DR. ELAWAR: This table shows the peak pressure results for the LOCA and steamline breaks as well as the pre-EPU results.

You see here, for example, Unit 1

steamline break, that pressure actually went down even though we're analyzing for EPU conditions. And, again, that's reflecting the beneficial modifications that were made there.

And essentially all these results benefit to some degree from the methodology change to MAAP-DBA. Again, we're raising initial pressure 4 pounds for these, so obviously we're getting some margin.

CHAIRMAN DENNING: When you show the pre-EPU, is that post-containment conversion?

MR. FREDERICK: No.

CHAIRMAN DENNING: No, that's pre-containment--

MR. FREDERICK: Prior.

MEMBER WALLIS: That's using a previous method of calculation?

MR. FREDERICK: Yes. It's using the Stone & Webster program.

MEMBER WALLIS: Okay.

DR. BANERJEE: What is the difference in the methods of calculations which give you the slide again?

MR. FREDERICK: Hit the backup slide.

This slide shows essentially how the peak pressure is sensitive to airborne water fractions. And that water fraction is essentially the water coming out of the break, what percentage of it is actually entrained into the atmosphere. In the previous methodology essentially there was no entrainment assumptions. It looked at other programs such GOTHIC. GOTHIC actually assumed a 100 percent entrainment.

MEMBER WALLIS: Oh.

MR. FREDERICK: And when we looked at this, the curve basically once you get to 10 percent, you don't get much more benefit. But 10 percent --

MEMBER WALLIS: There's a fog in there, you're saying there's a fog in there?

MR. FREDERICK: Yes. The water at entrainment essentially acts like an additional heat, so it gives you a benefit in the peak pressure.

MEMBER WALLIS: Airborne water fraction is the faction of the water which is entrained?

MR. FREDERICK: Yes.

DR. BANERJEE: Emitted?

MR. FREDERICK: The fraction of the water that is coming out of the break that is entrained.

MEMBER WALLIS: I would think getting a 100 percent of it would be a bit of a struggle, getting it all help up in the air. It's going to fall out, isn't it?

MR. FREDERICK: Well, some of it is, yes.

DR. BANERJEE: I think, I mean most of it.

MEMBER WALLIS: Most of it.

MR. FREDERICK: Well, we did provide as part of the submittal, we provided some comparisons to experimental data. I don't remember the experiments right off hand. But those results showed somewhere in the 50 to 60 percent range were entrained.

DR. BANERJEE: But you have surfaces where the water jet impacts, right?

MR. FREDERICK: Yes, and that does account for that. If there is collisions with surfaces and poor condensation for that matter, it is removed in that--

DR. BANERJEE: But nonetheless, it's a heat sink?

MR. FREDERICK: Yes, essentially.

MEMBER WALLIS: When you start out you've got to make a lot of dispersion. But as you put more and more water in there, there must be a lot of it that comes out?

MEMBER KRESS: Why isn't that below 45?

MR. FREDERICK: It's absolute. But this is not for our plant in particular. This is just --

MEMBER KRESS: Oh, I see. This is just for some plant.

MEMBER WALLIS: So what do you do? You assume something here or what?

MR. FREDERICK: Actually, for MAAP we assume 10 percent entrainment.

MEMBER WALLIS: It's just someone's educated guess?

MR. FREDERICK: It was a conservative relative to what we saw in the experiments.

MEMBER WALLIS: Well, it's interesting. How much mass of water is it then when it's 10 percent? Later in a LOCA it's a lot, isn't it? The air is holding all that up?

MEMBER SIEBER: You get a number of them.

CHAIRMAN DENNING: Well, wait a second. This is the large break and early time peak.

MEMBER WALLIS: Time is --

MR. FREDERICK: Yes, this is all currently in the first 20 seconds.

MEMBER WALLIS: So it's probably okay. Early time, yes.

MR. FREDERICK: Yes.

MEMBER WALLIS: Everything's stirred up.

MR. FREDERICK: Yes, it's very quick. Yes.

MEMBER WALLIS: I was concerned when you

say you assume something.

MR. FREDERICK: Just to cover the other criteria and results, we did show that we met the depressurization rate, time. NPSH requirements were satisfied. We also look at EQ, for example, if the envelopes change, we look at the equipment and we've done that. And as well as the structural issues, the piping and the sump inventory.

The next subject which is related --

MEMBER SIEBER: Before you leave, you said that even with the relaxation of the sub-atmospheric requirement you still returned to some sub-atmospheric condition following a LOCA. How long does that take? An hour?

MR. FREDERICK: I'm not sure I said that, Jack. But we can still get there is the river is cold enough. I mean, this is very much a function of the service water temperature.

MEMBER SIEBER: Okay.

MR. FREDERICK: Typically though --

MEMBER SIEBER: You don't necessarily go sub-atmospheric.

MR. FREDERICK: That's right. Right.

MEMBER SIEBER: And so from a Part 100 standpoint if you have some positive pressure --

MR. FREDERICK: And if some leakage occurs--

MEMBER SIEBER: -- you may see it on the outside, right?

MR. FREDERICK: For the dose analyses we assume leakage occurs for 30 days.

MEMBER SIEBER: Okay.

MEMBER KRESS: I think the section there is you use that high for the peak pressure after 24 hours, right?

MR. FREDERICK: That's reduced to half of that within 24 hours.

MEMBER KRESS: Regardless of what it really is? I mean, it's usually lower than that.

MR. FREDERICK: Yes.

MEMBER KRESS: But it's a conservative calculation?

MR. FREDERICK: Oh, yes.

Moving on to containment overpressure. For Beaver Valley Unit 1 the recirc spray pumps have credited in the past containment overpressure as part of our existing licensing basis. And for this analysis containment conversion and EPU we're continuing to credit that.

Unit 2 does not require any containment

overpressure --

MEMBER WALLIS: Are you crediting the same amount of overpressure for the same amount of time?

MR. FREDERICK: I'll touch on that. We have some slides that show that.

Unit 2 does not credit overpressure and never has. Physically the pumps are a lot lower so they don't have a need for that.

The Beaver Valley recirc spray system, essentially this is our heat removal function post-LOCA in the environment that each train consists of a pump, heat exchanger and spray ring. And it takes suction directly from the sump and delivers a spray flow for Unit 1.

MEMBER WALLIS: When you need it is when you have the high pressure in the containment.

MR. FREDERICK: That's correct, yet. The system was primarily designed to give you a rapid depressurization so you could meet the one hour sub-atmospheric requirement.

The backup slide just shows a sketch of the system, basically.

MEMBER WALLIS: Does it show the pressure needs versus time or something like that and how much you're actually crediting?

MEMBER KRESS: They're different.

MR. FREDERICK: Yes.

MEMBER WALLIS: That's coming up?

MR. FREDERICK: About 2 slides.

MEMBER WALLIS: We're waiting for that. That's the bottom line.

MR. FREDERICK: We're there. This slide shows you the containment over pressure required.

MEMBER WALLIS: You need 10 psi.

MR. FREDERICK: The COP required is basically how much pressure do I need above the initial pressure in containment to get enough NPSH. So, yes, when the pumps first start out, and again these pumps start relatively early, 5 minutes after we reach the high pressure setpoint in containment. So the sump is relatively hot at that point and there is not a lot of level. So the NPSH is somewhat limited. So we need containment overpressure at that point.

Well, let me make another point here. This shows the previous results from pre-EPU and actually pre-containment conversion.

MEMBER WALLIS: The Staff didn't give you any trouble with the blue lines so then they're going to accept the red line?

MR. FREDERICK: Yes. The blue line is

occurring, as you can see, for the EPU we're increasing--

MEMBER WALLIS: And you already have? You already have that approved the blue line?

MR. FREDERICK: That's correct, yes. The increase in actual pressure requirement is on the order of 2 pounds. Duration wise this requirement goes below zero, which means that we don't really need overpressure at that point.

MEMBER WALLIS: Not a very long a period of time compared with some plants.

MR. FREDERICK: That's correct, yes. The point here is that it's roughly ten minutes past the start of the pump.

MEMBER WALLIS: And for hours?

MR. FREDERICK: Right.

MEMBER SIEBER: For the inside research spray pump.

MR. FREDERICK: Correct. And this is for the outside.

MEMBER SIEBER: Right.

MR. FREDERICK: It's very similar.

MR. MANOLERAS: This is Mark Manoleras again.

Ken, why don't you go into detail on the testing of the pumps.

MR. FREDERICK: Yes, I'll get to it. It's a couple of slides away yet.

MEMBER WALLIS: Run without this COP?

MR. FREDERICK: Next one.

This slide shows the available overpressure against the required, the two bottom lines being the required. And what you can see here is actually when the pumps start. They actually start delivering flow about 300 seconds.

MEMBER WALLIS: Now this pressure that's available looks very high. Usually people make a lot of conservative assumptions. This looks like the real pressure. You're going up to 40 psi.

MEMBER SIEBER: Yes.

MEMBER KRESS: This is atmospheric.

MR. FREDERICK: This is actually overpressure.

MEMBER WALLIS: Yes.

MEMBER SIEBER: Containment pressure.

DR. BANERJEE: You have a pretty small containment, right, to get that?

MEMBER SIEBER: Smaller than --

MEMBER WALLIS: Usually you have a containment pressure that's high like that which you use to evaluate the integrity of the containment.

MR. FREDERICK: Right.

MEMBER WALLIS: And then you have a sort of minimum curve which has all kinds of conservative assumptions, which is much lower. And I don't see that there.

MR. FREDERICK: Well, again, you may not see it so much in the peak because that's not really effected by what we do in terms of trying to minimize the pressure.

MEMBER WALLIS: It's not?

MR. FREDERICK: You know, it's when you start the sprays and the peak is basically a function of how Tagami ends up. It's based on volume, energy release and the timing. So that's not something that would really change much.

MEMBER WALLIS: So is this blue curve conservatively estimated to be below the real pressure?

MR. FREDERICK: Yes. We do sensitivity studies that look at really the whole event, not just pressure because it's also a function of sump temperature. And some things that tend to reduce pressure also reduce sump temperature. So both of those are in the NPSH equation. So what we have done historically is we do sensitivity studies on all the sensitive parameters and determine what is the minimum NPSH available case, which is what's shown here.

MEMBER WALLIS: Well, this really should say minimum available overpressure or something, not a best estimate kind of calculation.

MR. FREDERICK: No. This is actually the--

MEMBER WALLIS: The conservative minimum.

MR. FREDERICK: This case reflects the minimum NPSH available result.

DR. BANERJEE: No. I mean the blue curve is the minimum containment pressure available? I mean if it's just about --

MR. FREDERICK: It may not necessarily be the minimum available. It's the minimum available associated with the set of conditions that come to this analysis.

DR. BANERJEE: With this -- yes. Sure. But for this set of conditions it's a large break LOCA or something, right?

MR. FREDERICK: Yes.

MEMBER KRESS: We once wrote a letter that said those calculations ought to have probabilities in them to see how much the probabilities overlap to get some sort of probability that you would have --

DR. BANERJEE: No. Uncertainty anyway.

MR. FREDERICK: And we actually have some stuff in here on that, too.

MEMBER KRESS: Yes.

DR. BANERJEE: If not probability, at least uncertainty.

MEMBER KRESS: Uncertainty. Yes.

MEMBER WALLIS: We did write the letter. We got several members who endorsed additional comments, wasn't that --

MEMBER KRESS: Yes, as I recall.

CHAIRMAN DENNING: You only spray in recirculation mode? You don't spray from the refueling water start --

MR. FREDERICK: No, we do both.

CHAIRMAN DENNING: You do both?

MR. FREDERICK: Yes, and that's what you can see here. I mean, we're going from 40 pounds down to nothing in a little over 10 minutes.

CHAIRMAN DENNING: That's due to spray?

MR. FREDERICK: Yes. So once the spray start, we have a quench spray system which comes from the RST which is --

MEMBER WALLIS: If the pumps weren't working, the blue code would be higher? So it's a kind of self-controlling situation?

MR. FREDERICK: That's correct, yes. The reason we need overpressure is because we're running the sprays. And you can see the pressure comes down pretty quickly once those sprays go on.

MEMBER WALLIS: The sprays themselves reduce the overpressure?

MR. FREDERICK: That's correct.

MEMBER SIEBER: And if you didn't have the overpressure, you wouldn't need the sprays.

MR. FREDERICK: The problem with not having the sprays is that it's our only means of getting heat out of the sump.

MEMBER SIEBER: Right.

MR. FREDERICK: We need the heat exchangers more than we need the sprays.

MEMBER SIEBER: Right.

MEMBER WALLIS: When you need the sprays, they work?

MR. FREDERICK: Yes.

DR. BANERJEE: Those little side diagrams, maybe we should get copies of those because they have -- yes.

MR. FREDERICK: Just a point there. Again, that was the NPSH limited case. It's not necessarily the longest duration. For all the cases we look at, the most amount of time that we need for overpressure credit is 20 minutes after the pump starts.

And we did do some testing of these pumps way back in the late '70s. Actually, it was North Anna pump that was tested, but they're basically identical to ours.

Hit this backup slide. They actually ran these pumps at reduced NPSH all the way down to about 4 feet available, the left line there. And basically you can see, as you reduce NPSH below the required, the performance suffers. But they ran these up to about a half hour in this reduced NPSH mode.

MEMBER SIEBER: And they still pump?

MR. FREDERICK: And they still pumped and they tore them down, and there was no damage to the pumps.

DR. BANERJEE: Well, there was some cavitation, but --

MR. FREDERICK: Yes, obviously it's offering in a cavitation --

DR. BANERJEE: Not significant. Not until to --

MEMBER WALLIS: Until they fall off the cliff there.

MEMBER KRESS: Even with the required net positive suction you had some cavitation, right?

MR. FREDERICK: Yes, 3 you're percent reduced by definition.

MEMBER KRESS: Yes. Yes.

MR. FREDERICK: Go back.

DR. BANERJEE: Excuse me. Go back to that slide.

What is there, I can't read that very well, but what is the suction head required. Yes, I can't read the ones on top there.

MR. FREDERICK:

(Off microphone).

MEMBER SIEBER: You have to talk into a microphone.

MR. FREDERICK: Right.

DR. BANERJEE: Is that 16, 14? The four I can read, but beyond 4 I can't read any of those. They're blurred.

MEMBER WALLIS: Are you saying that even if there were no overpressure available they'd still work? If you lacked 10 psi, will they still work or not?

DR. BANERJEE: These are in feet of water, I take it.

MEMBER WALLIS: Twenty feet of water, do they still work at 20 feet of water.

DR. BANERJEE: No, there are 4 feet of water, they would work.

MEMBER WALLIS: Yes, but not at 20?

DR. BANERJEE: No, at 20 they'd work perfectly.

MEMBER WALLIS: Oh. Well, you've got 4 feet, don't you? What is that you need? You need--

DR. BANERJEE: 11.5 feet. Is that your reference is, 11.5 feet of NPSH on this?

MR. FREDERICK: For these pumps the minimum required that we use is 9.8 feet.

DR. BANERJEE: 9.8 feet. All right. So that's the one, Graham, which is the fourth line down from the top.

MEMBER WALLIS: That one there?

DR. BANERJEE: That's your reference, right?

MR. FREDERICK: Yes.

MEMBER WALLIS: And how compact can it get and still satisfy your needs there?

MR. FREDERICK: Four feet available, that would be something around 2 psi overpressure --

MEMBER WALLIS: It's still pumping.

MR. FREDERICK: -- still required.

MEMBER WALLIS: But that's much less than you're asking for?

MR. FREDERICK: Yes. This is a kind of margin we don't use these lower limits in anyway or we don't model the pumps in a degraded performance.

MEMBER WALLIS: It seems to depend a lot on the dynamic head required. How much is the dynamic head required? There's a load line somewhere here.

DR. BANERJEE: Right, that's what I was going to ask. Where is that load line? Just conceptually if you sketch it.

MR. FREDERICK: Well, these pumps normally operate around 33 to 3500 so your system curve comes through here somewhere.

MEMBER WALLIS: So some of those have already crashed and gone over the -- they went over the precipice by the time they come down to the load line?

MR. FREDERICK: Well, yes, you would see a much reduced flow but you would still get some flow.

CHAIRMAN DENNING: But in reality isn't it just a matter that you don't want them to fail. Because suppose for 20 minutes they didn't work and they didn't remove heat, isn't this really a real long term problem that you're concerned about, which is long term heat removal.

MR. FREDERICK: Yes.

CHAIRMAN DENNING: So the fact that they're not able to keep up with heat rejection during this period when you really need it doesn't really matter.

MR. FREDERICK: If we have reduced heat removal, the ultimate effect is that the sump's a little hotter a little longer.

MEMBER WALLIS: So you'll get 2000 GPM instead of 3500 or something?

MR. FREDERICK: Right.

MEMBER WALLIS: And it's no big deal?

CHAIRMAN DENNING: As long as you --

MR. FREDERICK: It only last for 10 or 20 minutes, yes.

MEMBER MAYNARD: I think the more significant part of this what shows is that they operated for a long period of time, it reduced NPSH and did not fail the pumps and they were still in good shape.

MR. FREDERICK: Yes.

CHAIRMAN DENNING: Okay. Continue.

MR. FREDERICK: Next.

We looked from the PRA aspect of this, you know what's the probability of losing containment isolation which could lead to loss of overpressure. And we estimated that to be about one times 10 to the minus 8. And that's based on the LOCA coincident with failure of isolation for the lines that communicate directly with the containment atmosphere. And those lines for Beaver Valley are actually pretty small. The largest such line is a 2 inch line.

CHAIRMAN DENNING: Since you're still operating a little bit sub-atmospheric, does that help your probability here? Do you know that you're isolated?

MR. FREDERICK: Yes. Essentially we would screen out any large preexisting failure because we would notice that if it occurred.

DR. BANERJEE: Is there any interaction with a LOCA which would sort of tend to make you lose containment isolation?

MR. FREDERICK: No. All of our containment --

DR. BANERJEE: Nothing that --

MR. FREDERICK: -- systems are fully qualified.

DR. BANERJEE: Completely independent?

MR. FREDERICK: Yes. We actually did an analysis where we looked at -- you know, essentially run the NPSH cases with holes in containment. And we did up to a 3 inch based on what our penetration size are.

And if you look at the next slide here essentially all the results are on top each other so there is no significant effect of opening a small hole in containment. Again, that was the most probable based on the actual penetration sizes that are open to containment atmosphere.

DR. BANERJEE: But then what happened to the pressure as you open the hole?

MR. FREDERICK: It didn't change much.

CHAIRMAN DENNING: You can't tell at that small hole size.

MR. FREDERICK: Right. Essentially there's a minimal change in the pressure response such that the NPSH margin doesn't change much.

Next slide.

We do a conservative analysis in terms of minimizing the overpressure available. We do not ask the operators to intervene in anyway to try and maintain pressure at a certain value or certain limit to try and assure that we have available COP.

MEMBER WALLIS: Suppose the screens were getting block, how would the operator know it and what would he do?

MR. FREDERICK: I'll let my operator handle that one here.

MR. DURKOSH: This is Don Durkosh again.

Recently, probably within the last year or so, we've implemented sump blockage guidelines. And we've updated our emergency procedures. So basically when we enter the recirc mode we have RNO, response not obtain actions where we would start a pump or verify a pump is running. And we would monitor things like pump amps, discharge pressure and flow. And if we see any variations, then we have a sump blockage guidelines available to us.

And in the big scheme what the sump blockage guidelines really do is have you look for ways to reduce flow, which would reduce the line losses across the sump screens. So basically kind of get you to reduce the flows, get NPSH back into an acceptable range and operate in that mode.

MEMBER WALLIS: You don't backflush or anything like that?

MR. DURKOSH: Not at this time.

MEMBER MAYNARD: I wouldn't think that the things you would be looking for would be much different than what you in mid-loop operation, making sure that your RA pumps are cavitating or lose suction. I mean it would be a similar situation with the sump.

MR. DURKOSH: I agree.

MEMBER MAYNARD: Yes.

DR. BANERJEE: Are we going to talk about sump blockage at some point?

MEMBER WALLIS: Yes, you are.

CHAIRMAN DENNING: You already have as much as we are.

DR. BANERJEE: Because it was be interesting to know how difficult it would be to backflush.

MEMBER WALLIS: I think it's taboo, though.

CHAIRMAN DENNING: Yes, I think we shouldn't be talking about that now, no.

MEMBER WALLIS: That's another subject.

CHAIRMAN DENNING: I mean it's interesting to see what they are going to do.

DR. BANERJEE: But you're going in for an EPU. You may as well put it in.

MEMBER WALLIS: Yes, but it's a generic

issue.

MR. CARUSO: Yes, but it's a generic issue and we don't resolve generic issues.

DR. BANERJEE: Okay. We won't resolve it.

MEMBER WALLIS: You don't dump it all on one licensee.

CHAIRMAN DENNING: We just initiate generic issues under this.

Okay. Proceed.

MR. FREDERICK: Just to finish up this slide, we did look at potential modification that could be made to eliminate the need for containment over pressure and essentially they're all impractical.

MEMBER WALLIS: I'm curious. You're putting in a bigger screen. What design is it?

MR. FREDERICK: Design in terms of -- hit the back slide.

MEMBER WALLIS: This is a whole lot of cylinders or --

MR. FREDERICK: Yes, it's an array of cylinders.

MEMBER WALLIS: An array of cylinders.

DR. BANERJEE: But is this the top hat design.

MR. FREDERICK: Yes.

MEMBER WALLIS: Okay. Ah, so the problem there is to figure out how that performs when you've only tested one?

DR. BANERJEE: Yes, it's the same problem-

MR. FREDERICK: Our testing is actually looking at it.

MEMBER WALLIS: Testing arrays?

MR. FREDERICK: I think we're do a 9 set of array.

MEMBER WALLIS: Oh, okay. Okay. Thank you. That's better than one.

MEMBER SIEBER: It looks like that would take up a lot of space.

DR. BANERJEE: Then it would be prudent to do backflushing.

MEMBER WALLIS: It's not difficult to figure out that works.

MR. FREDERICK: Just summarizing I guess for the containment overpressure, COP is required for Beaver Valley Unit 1 RS pumps. And it's part of the licensing basis. And it's continued to be credited in the recently approved submittal.

We have run these pumps at reduced NPSH with satisfactory results. And we looked at the risk of losing overpressure, and it's very low. And we also looked at modifications to eliminate the need, and they're not practical.

The next two slides --

CHAIRMAN DENNING: You can go quickly on these I think.

MR. FREDERICK: Yes. These essentially summarize the dose assessment results from the accident analyses.

Again, we're moving to full implementation of the alternative source term and we've updated X/Qs with more recent meteorological data and we've also switched to ARCON 96 for the onsite X/Qs.

We've incorporated the results from our control room tracer gas testing.

Unit 2 continues to use the alternate repair criteria, which develops the accident induced leakage limits. And all the results are within the 50.67 limits, as you can see on the next slide.

Again, here the Unit 2 value is maximized based on the alternate repair criteria methodology.

Just to summarize for safety analysis. Again, we've looked at the required events. All the acceptance criteria seem to be met at the EPU conditions. And we feel like we have enhanced the plant in some way with the modifications we've made and are beneficial impacts in terms of the safety margin. And we've been able to retain a lot of the safety margin.

That's it. Any questions?

CHAIRMAN DENNING: Are there any questions on safety analysis here? Anything that we want to prod for more information tomorrow?

MEMBER WALLIS: I want to know what the Staff thinks about the containment overpressure, but that's not any of that today.

CHAIRMAN DENNING: That's to come.

Okay. Thank you very much.

We're now going to go in recess until by that clock up there it's going to be -- we'll make it a quarter of by that clock.

(Whereupon, at 3:33 p.m. a recess until 3:50 p.m.)

CHAIRMAN DENNING: Okay. We're now back in session. And we're now going to hear about the Staff's view of safety analysis SBLOCA.

DR. WARD: Can you hear me? Okay.

My name is Len Ward, I'm in NRR in the code review analysis branch. And what I'm going to talk about, I'm going to talk basically about post-LOCA long term cooling, and that's large and small break, but then I'm also going to talk about short term behavior small break LOCA.

But before I do that, what I wanted to do is just quickly go over the ECCS system that's used to control boric acid, what's the approach. And then I'll talk about large break LOCA and small breaks.

Now Beaver Valley, it's a 3 loop plant. It's about an 8 percent power increase.

MEMBER SIEBER: Do you want a pointer?

MR. LEE: Yes, you know, I thought I had one here. Here we go.

A key ingredient here in this plant is that it has three accumulators. And as you heard earlier, the pressure was increased to 625 pounds and that's key for short term small break LOCA behavior.

And I'll also be talking about the switch to simultaneous injection and because of the way the ECCS is aligned, because of the ECCS configuration, cold let breaks are limiting in this plant for boron precipitation.

As I said, large breaks to control boric acid, you realign the ECCS, that's the high pressure safety injection pump to deliver half the flow in the hot leg and the other half in the cold leg. And I'll be showing you some calculations that I did to audit the precipitation times that the licensee performed.

I'm also going to talk about small breaks. And it was mentioned before, but small breaks you can hang up at a higher pressure. You don't go down to 147 where you're basically at run out on that high pressure pump. You had some intermediate pressure. It could be 200 pounds, 100 pounds. When you split the flow between both legs it's not enough the flush the core. So what do you do? Well, you cool the plant down. And you cool the plant down to a low enough pressure so that you either get it low enough so that you can flush the core when you switch simultaneous injection or you've cooled it down low enough and fast enough so that you refill the RCS with ECCS coolant, you reestablish single phase natural circulation and you disperse the boron. Okay? And I'll show you some calculations that we did to illustrate that.

MEMBER WALLIS: Even though there's a break, you can fill that whole thing?

DR. WARD: That's right. We're talking small breaks, one inch, two inch, three inch; they're really tiny. You'll fill it back up. I'll show you that when I get to the slide.

MEMBER SIEBER: It's the pot. The break's above the pot.

DR. WARD: The break's in the cold leg.

MEMBER SIEBER: Right.

DR. WARD: Or the hot leg. And the alignment is done such that you don't need to know where the break is. And the analysis is done so you don't need to know necessarily. It's nice to know what the concentration in the core and vessel is, but you don't need to know that. If you do a bounding calculation on precipitation time, all the operators have to know is when the accident started and at certain times you just go switch. And it doesn't matter what the break location is or where the break is.

DR. BANERJEE: When the HPSI are there line sizes indicator of the flows or is it --

DR. WARD: No, that's just where it's going.

MEMBER WALLIS: It's not to scale or anything?

DR. WARD: This is not to scale. So what I want to do is to show you for a cold leg break, before you switch to simultaneous injection you're injecting into the downcomer. You're storing some of it out the break.

MEMBER WALLIS: Right.

DR. WARD: But because there's no flush, okay, you're going to concentrate boric acid in the vessel, in the upper plenum in the core. And basically -- let me use this. This is better.

I mean what happens is you're going to fill the downcomer to the bottom of the cold leg. You can't get anymore water in there because the break's there. Anymore water you add spills.

The water that flows in is dependent on the low pressure drop. And the model I'm going to show you, and it's consistent with the licensee and vendor, it considers the pressure drop. So I have a fixed head here. Depending on the core power level, time and the event, that determines the steaming rate. And that determines where the two phase level is. So in the beginning of the transient very early the two phase level is low. It will grow --

MEMBER WALLIS: It's not on top?

DR. WARD: In the beginning, that's right, you've blown down the core. I mean, the whole core is voided. Now you're refilling. This is early. And it's slowly going to fill up. And I'm only going to be able to get enough water in here that the loop resistance will allow me. My ability to get water into this core isn't any better than my ability to relieve the steam around the loop.

MEMBER WALLIS: And the boron comes in and doesn't leave, so it just builds up?

DR. WARD: No. It just builds up. Right. And that's why with cold side injection, that's why cold leg breaks are worse for boron precipitation.

MEMBER WALLIS: You get some water in is because there are other cold legs from that one, so the water can get in?

DR. WARD: That's correct. Yes. There are two other loops. So this is spilling and the other one's keeping me full here. For this plant within about 45 minutes to an hour, the two phased level is up here above the bottom of the hot leg.

DR. BANERJEE: What's the partition coefficient of boron between the steam and the water.

DR. WARD: What's the what?

DR. BANERJEE: Partition. I mean it's partitioned, right?

MEMBER KRESS: It depends strongly on the pressure and temperature.

DR. BANERJEE: I see.

MEMBER KRESS: Low pressure it stays behind and high pressure it goes with the steam. It's a variable

MEMBER WALLIS: With these pressures it stays behind.

MEMBER MAYNARD: Not much stays behind.

DR. WARD: We're assuming the steam does not remove any of the boric acid nor is there taking any credit for any entrainment. You look at the UPTF tests, they show entrainment for about the first 15 minutes. For every pound of steam you're producing, you're taking 2 or 3 pounds of liquid out. So you're not going to build up very fast at all in the first 45 minutes. But that's neglected as well.

I mean so basically what I was going to say, if you want steaming in the core and I fill the vessel up, I'd have water here. But since I had void in it and if the loop pressure drop isn't a consideration, I' going to swell up into the hot leg. And I'll probably swell -- I won't swell the two phase level any higher than within maybe a half of foot to the top of this hot leg because the steam's got to get out and it's going to pressurize. And you're going to sit there concentrate.

Now, they don't take credit for the volume above the bottom of the hot leg. They're just taking credit for the mixing volume here, the core and half of lower plenum. And the void fractions coming off the top of the core early in the event throughout to about 6 hours is anywhere from 80 to about 65/70 percent. So it's pretty high. There's not much liquid in this region hardly at all. I mean, it's very hard. The void fraction, a very healthy steep gradient from zero to 70/80 percent at the top of the core.

MEMBER WALLIS: I asked the question previously, when you begin to get very high concentrations of boron, doesn't that change the formability and the drift flux and all that kind of thing?

DR. WARD: Yes, i think it does.

DR. BANERJEE: I probably does.

DR. WARD: Yes. I mean --

MEMBER WALLIS: But that would make a difference to the carryover.

DR. WARD: What I did in sensitivity studies, you saw the Waterford report in there.

MEMBER WALLIS: Yes.

DR. WARD: I varied the drift velocity by a plus or minus 25 percent. And, I mean, I'll show some precipitation times. But when you're precipitating out around 6 to 8 hours and in reality you're really not going to get there until about 15, 14 or 15 hours and that's where this plant's at. And I'll show you why that is.

A change of 25 percent in the drift velocity is probably not going to make much difference. I mean, if the drift velocity goes down, then I'm going to swell more, I'm just distributing the liquid and steam over a larger volume. I still got the same amount of liquid.

MEMBER WALLIS: The question we raised, which I don't think was every answered, you know when you boil down something like maple syrup it's just like boiling water. But when you get it up to the point where it's strong enough, it boils like milk. It's overflow and go all over the kitchen because the foaming --

DR. WARD: If it foams --

MEMBER WALLIS: It doesn't break. It just--

DR. WARD: I don't think the BACCHUS test showed that, but -- Yes but I mean those are good questions. But what we have done, and I mentioned this to you the last time we talked -- you had a lot of questions --

MEMBER WALLIS: Yes, but answers --

DR. WARD: And you've had a lot of good

questions today, and you haven't got all the answers. And I don't know all the answers because I want to know the answers to them, too.

We sent a letter out about 8 months ago, about a 15 page letter with about 20 or 30 questions asking what's the effect of boric acid on drift velocity, what's the effect on viscosity, surface tension, show us what the concentration profile is across the core, what's the effect of adding debris in here, how does that effect the concentration?

MEMBER WALLIS: Was this all to Beaver Valley?

DR. WARD: All those questions are in there. And we are --

MEMBER WALLIS: Is this to Beaver Valley or is this a generic question to the industry?

DR. WARD: It's not the strict sense generic letter issue. What we've done is we've sent a letter to all the vendors asking them to answer this question.

MEMBER WALLIS: Okay.

DR. WARD: And address these model concerns--

MEMBER WALLIS: So then you'll report to us on what happened some day?

DR. WARD: And we will.

MEMBER WALLIS: Okay.

DR. WARD: But I haven't heard anything yet. I know they're working on it. I think they're still digesting it. And I think they're planning to do calculations, experiments or whatever. And so when that's done, then we will come and present that to you.

MEMBER WALLIS: Okay. Good. Thank you.

DR. BANERJEE: A couple of these questions clearly can be answered fairly easily, viscosity surface --

DR. WARD: Sure. Sure.

DR. BANERJEE: But the drift velocity is more difficult. And I guess maybe the people at MHI would know the answer to that.

MEMBER WALLIS: But does it boil over? We just need to put it on the stove in your kitchen and wait.

DR. BANERJEE: Well, that's a good way to do it, too.

MEMBER SIEBER: Another way.

MEMBER WALLIS: Well, it's best to do it outside on the grill or something.

DR. WARD: Yes, right. Right. Well, those questions have been asked. And again, when we've had meetings with -- when we get some of the results from all these questions, then we'll be happy to share them with you.

MEMBER WALLIS: If I buy some borax and dissolve it in water in my kitchen, can I boil it and see what happens?

DR. WARD: Sure. I mean --

MEMBER WALLIS: Would that be realistic?

DR. WARD: Well, there was a test done, and I probably shouldn't -- you know, I'm not sure if I should mention it or not.

MEMBER WALLIS: Well then don't.

DR. WARD: So I can't. But if you took a plexiglass vessel and pumped borated water into it, an electrically heated core and you pumped it in at the RWC concentration of roughly -- now they're up around 2600 ppm, and if you took pictures of it you would see because if the water's cold coming in the lower plenum, you see some crystallization even on the surface. But the test would probably show mixing throughout the entire lower plenum and core. And there'd be a gradient in there. But once it precipitates, when you hit that limit based on whatever pressure you're at, it's probably going to look like you filled that whole thing up with salt. Lower plenum core and upper plenum is going to be looks like full of table salt, crystals.

But, you know, there may be some worm holes through it. You know, there are some cooling channels that may be there. But that's probably what's going to happen.

But what I'm going to show in this calculation so we don't get anywhere near that --

MEMBER WALLIS: But it would be slurry cool. It would be slurry cooled. It won't freeze up solidly?

DR. WARD: Yes. Probably.

But I want to show you. hopefully we shouldn't get anywhere near there. And there's enough margin to accommodate. We don't feel that there's answers here, we just want to make sure the industry is doing everything consistent. They're not using a 1.0 multiplier. They'll all using appropriate mixing volumes. They're taking credit for the void fraction in there instead of assuming it's full of liquid, and they're not assuming the whole mixing volume is this size from time zero on, because it grows. So let's do it right. And they are doing that. And they're starting to do that now.

So let me just go over some of the assumptions. I've already discussed it. We're only taking credit for half -- they're only allowed to take credit for half the mixing volume in the lower plenum. The core and the upper plenum, they choose to just credit the volume below the bottom elevation of the hot leg.

Now this was done during the Waterford review, and you'll remember that. I did some calculations. Compared my model to that. And as I recall, it's been a while since I looked at it, the reason why we did this is because since it's an average concentration, it more closely tracked the concentration near the top half of the core instead of some lower average. So they're only allowed to take credit for half of the lower plenum. And I think there was some mixing in the upper plenum, too. But we predicated the precipitation time within an hour. So for a crude model like that, it's probably not too bad.

We're using the 1971 ANS decay heat standard with an additional 20 percent. It's like the plant's operating at 20 percent more power.

The mixing volume is calculated as a function of time. The higher the steam rate, the slower the growth of the two phase level and a mixture of volume in the vessel.

Now this is not a model assumption, but I just wanted to point out that the source concentrations for this plant are 2600 ppm. And again, the cold leg break is limiting for precipitation.

What you want to do --

DR. BANERJEE: 29.27 percent or what?

DR. WARD: That's at 14.7 -- that assumes the pressure in the upper plenum is 14.7.

DR. BANERJEE: But it must include the boiling point.

DR. WARD: That's the boiling point at 14.7 with boric acid in there.

DR. BANERJEE: So what's the --

DR. WARD: The upper plenum pressure is going to be more -- upper plenum is going to be more like 20 or 25 pounds pressure. So the precipitation limit is not going to be 29. It's probably going to be more like 32/33.

And now our additives in there that will jack it up to about 40 percent. But we're going to assume -- the licensee assumed conservatively 29 percent.

Now hot leg break. I guess I don't need to -- if you have a hot leg break, clearly during the injection phase --

MEMBER WALLIS: Flushes it down.

DR. WARD: You're going to flush this thing fairly quickly because you're going to fill it up. And once the two phase level in the vessel gets above the bottom of the core, it's going to start flushing. AS a matter of fact, it's going to have positive flow through there and I don't think they're going to build that much boron at all. So that's why hot leg breaks are clearly not the thing you want to look at.

Now, if you take that model, and it's the same model that I described last time and it's documented in the Waterford report. So if you want to see the physics of the model, it's pretty simple. It's hydrostatic balance against a loop pressure drop where the drift phrase model calculates a two phase level. And that drift flux model is compared against test data that I've shown you on AP 1000. But it's documented again in that report. So if you want to see anything more on that, you know, feel free and I'd be happy to come over and explain it in some detail.

I want to show you the calculation that I did compared to the Westinghouse calculation. And this is the concentration as a function of time. You can see that the Staff model predicts the Westinghouse calculation, and I used this decay heat, their sump concentration as a function of time which they calculated. Basically used the same assumptions in the calculating a precipitation time, which is within 15 minutes.

DR. BANERJEE: Based on the same volume?

DR. WARD: Based on the same mixing volume. That's half below plenum, that's the core. And only the volume in the upper plenum below the bottom elevation of the core.

Now they could have taken credit for the volume in the upper plenum adjacent to hot leg because the level swells up to there within about an hour, hour and a half and it's going to sit there near the top of the hot leg. So there's an additional 200 cubic feet.

The lower plenum in this plant's about 750 cubic feet. So we're getting about 325 in the lower plenum. Let's see, the core area as I recall is 42 square feet, the height's 12½ feet. So you've got about 400 in the core and another 200 in the upper plenum. And in the hot leg, they've got about another

200 cubic feet, but that's being neglected.

And remember, the steam doesn't carry it away. There's no entrainment. The upper plenum pressure is 14.7. I'm not taking credit for additives. I'm up here if I take credit for the additives. I know we don't like to extrapolate, but gee, we're talking --

MEMBER WALLIS: Ten hours.

DR. WARD: -- 10 hours or more. And they're switching at 6 hours. I guess they're starting at five. I'm sorry. So I mean there's clearly 4 or 5 hours there of margin relative to these.

MEMBER SIEBER: Volume of the core is not the product of the physical dimensions because the core itself occupies about half that space, right?

DR. WARD: That is the free space. That's the free area.

MEMBER SIEBER: That's the --

DR. WARD: That's in between the rods and the --

MEMBER SIEBER: Okay.

DR. WARD: Yes. It was the core flow area. Okay.

That's a conservative calculation. I mean, it's bounding.

Now what I want to do before I talk about boron precip for small breaks, let's talk about the -- yes, blurry. Can you see that okay?

MEMBER SIEBER: Yes. Better than the other one.

DR. WARD: Okay. The old technology works.

When Veronica Klein and I looked at the spectrum, we noticed they only looked at integer break sizes. And if you look 1, 2, 3, 4, 5, 6 inch diameter breaks, you find the area is .0055, .02, .05, .09, .14; there's a pretty wide range there. And typically for small breaks the limiting break is usually in the .05 square foot range, somewhere in here and it's typically a break that's controlled entirely by HPSI flow, which means you find a break size with a system depressurizer and it hangs up just above 600 pounds. The HPSI flow doesn't put as much flow in as an accumulator so it's going to uncover and then slowly recover. And typically that's the worse small break.

For this plant the accumulator comes on during that range. We asked them to do a more detailed spectrum analysis, and you saw that plot. Maybe quarter inch. They went every quarter inch between 2 and 3 and 3 and 4 and found out that breaks between 2 and 3 could be more limiting. The worse break turned out to be a 2.75 inch break compared to the original analysis submittal of 1759. Now this is not one-to-one because I think the 1917 degree F PCT is a time in life study for oxidation. I think the 2½ inch break was worse because although the peak didn't quite get up, it was uncovered longer so the oxidations were like 13.42 percent. But basically what this did looking at a more detail spectrum, better identified the PCT. And when you got these high power uprates, I've seen a plants with a difference of .005 square feet, the PCT can increase by 70, 80 degrees. So when you're getting p around 1900, 2000 if you want to make sure the margin by Appendix K is there, then you need to do this. You need to do a better calculation.

Now we did some calculations. Veronica Klein and I did. Veronica did most of the calculations.

DR. BANERJEE: This is by using your --

DR. WARD: This is RELAP5. No, this was RELAP5. We had a deck. And we got it -- we might have gotten from the licensee and we thank them for that. They have been very cooperative in answering all questions. In trying to understand their model, I've even asked them to do some calculations so I can understand how their model behaves. And they answered everything.

DR. BANERJEE: What is actually run here for the RELAP5? Is it just the core region?

DR. WARD: No. This is the entire system. It's your full blown RELAP5 model, okay. Vessel, each loop. Now we've got 24 cells in here. Better track the two phase level. And also put a hot bundle in there with 24 cells in it with a hot rod in it.

DR. BANERJEE: And this is the low pressure long term --

DR. WARD: No, this is short term. This was for PCT. No, no. The boron precip stuff is --

DR. BANERJEE: But you don't continue this into the low pressure?

DR. WARD: Yes. I ran this all the way out to 8 or 9 hours to show refill. And I'll get to that on the long term part. We ran this for short term to look at PCT. We also ran it to show for small breaks where you can't the pressure down low enough to flush the core, but you can refill the core or resubcool it, reestablish single phase natural circulation and disperse the boron. It was run for that. I'll show you some of those.

DR. BANERJEE: Yes, how does it behave at low pressure?

DR. WARD: Well, great. I mean ask Veronica. I mean, Veronica never came in my office once and said "Damn code bombed again on properties." Never said that once. Run these cases up two hours. We ran .5, .75, 1 all the way up to one square foot. We looked at breaks on the top of the pipe because the lube seals would fill up and potentially depress the core. And we also looked at side breaks. And we found that the most limiting break was between these 2 and 3 inch range. A little different break because they're different critical flow models. But we basically beat it to death.

And we ran these tiny breaks half an inch, 1, 2, 3, 4 out 30,000 seconds.

And running with a .05 second time step, the case runs in two hours.

MEMBER WALLIS: You didn't use TRAC?

DR. WARD: No. I didn't have an input deck for it.

DR. BANERJEE: But I thought this was seamless now, conversion from a RELAP5 deck to TRAC?

DR. WARD: Not quite.

DR. BANERJEE: Little seams still there?

DR. WARD: Yes, there's some bugs in it, you know. The control system you've got to develop. They're not quite the same. You know, the RELAP5 input is a little different, but they're getting there. Not quite there yet.

DR. BANERJEE: Okay.

DR. WARD: They're working feverishly on it.

So I guess I've already said that. So basically we confirmed the worse break, ran it 14 kilowatts per foot, I think it's a little higher at the extended power uprate value. And what I want to do is show you this break between 2 and 3 inches.

And the thing I want to point out is the accumulators. The accumulators are keeping the PCT down below 2000 degrees. And you can see they're coming on here. So the system pressure then rises. They cut back off because it fills the core back up and so there's more energy addition, the pressure goes up. And there's a balance between energy addition and break flow. And so you don't get a huge deluge but it's enough to turn that temperature over. So the accumulators are really controlling PCT here. So if anybody says accumulators are there for large breaks.

No, small breaks. That's why they're there. That's why they're important.

I'm not going to bore you with the results, I just thought I'd show you a PCT plot. And there's 24 cells in the core, so the peak, the peak is in the top four cells. Temperature is around 1900 degrees.

DR. BANERJEE: When do the accumulators kick in that?

DR. WARD: The accumulators kick in right about here and then they deliver enough flow and they turned it over right here. The accumulators are kicking in right about here.

MEMBER WALLIS: That's 5 or 6 hours.

DR. BANERJEE: And what are those two curves?

DR. WARD: Those are two different axial slices. This is cell 22. That's two cells from the top of the core. And this is cell 20. It's 24 cells in that. That's in the hot bundle. So if you want to capture the shape and the void distribution at two phase level, you really need -- I wanted to make sure we had enough detail in there to capture it.

DR. BANERJEE: These are the hottest areas?

DR. WARD: This is the hot bundle. Right. The hottest bundle in the core and the hot rod with the 1400 kilowatts per foot approximately 2 or 3 feet from the top of that core.

Now remember this is Appendix K. This is 20 percent more power than is really there. If we rerun this with 1.0 multiplier, this temperature is going to come down here. It's just like increasing the HPSI flow by 20 percent. That's huge. So it's a pretty big conservatism.

That's probably the conservatism.

And we can skip the next one. It's just another break size and it just shows you the accumulators are controlling PCT here.

I'm only going to mention this quick. If you look at those slides, you'll see a first peak here. There's an early CHF condition. Westinghouse didn't calculate it. I did. It's about 2000 degrees. And I'm not quite sure. We haven't really figured out what's causing it, but my suspicion it's a combination of two things. I'm assuming a reactor trip at the time you get -- I'm assuming a loss of offsite power at the same time you would get a reactor trip on a low pressure during that event. What that does is it says the -- start coasting down and I got about a 2 second delay before rods go in, so I've got two to three seconds before the rods in far enough where I'm generating full power and I'm voiding that hot bundle, very quickly and rapidly, and I get a heat up.

MEMBER WALLIS: And you said Westinghouse didn't calculate them?

DR. WARD: They made the same assumption in their model tripping it at the same time and they're not getting a first peak.

DR. BANERJEE: They used NOTRUMP, right?

DR. WARD: They're using NOTRUMP, I'm using RELAP. Now, I've got a single hot bundle channel with cross flow.

DR. BANERJEE: How far into the transient is this?

DR. WARD: It's right at reactor trip.

MEMBER SIEBER: Two seconds.

DR. WARD: It's two seconds in. Once I get reactor trip --

MEMBER WALLIS: So it still meets the regulation?

DR. WARD: It meets the regulation. The bottom line is it's still below 22. I've never seen a first peak much over 2000. It's usually anywhere from 1400 to 2000 degrees. But I only mention it, you know, we've been talking to each other. We want to get to the heart of it and figure out what -- there's probably differences in the model. It could be input. You know, I'm not sure. But I just wanted to mention it because it's there and however even if we're conservative in the resistance and the way we modeled it, it's still -- the PCT is still less than 2200.

DR. BANERJEE: Your model is a two fluid model whereas theirs in some form is always a mixture model of sorts?

DR. WARD: Yes. It's drip flux approach.

DR. BANERJEE: Yes. So you cannot decouple of the phases which you can?

DR. WARD: Right.

DR. BANERJEE: So they're bound to move --

DR. WARD: Right. Yes.

So anyway, what we'll do, we'll follow up with this. If it looks like we need to pursue this farther, then we will. But I think we probably, we'll be able to resolve this once we have the time to devote to it. More important things were long term cooling, operator actions and behavior.

Now what I'll do is get into the small break. And as I said, small breaks pressure can hang up 1 or 200 pounds for these tiny leaks for long periods of time. And the pressure remains too high and you can't flush. So what do you do? You've got to reduce the pressure to low enough to flush it or cool down early enough and fast enough within your cool down tech spec limit and refill this thing and resubcool it.

And this was an open item identified in the SER, but we're very close to getting closed here. The licensee has done their calculations. I haven't seen them yet, but once I see them and I can see that they've got essentially the same response that I did, then that will be a closed door. But --

MEMBER WALLIS: This comes to the full Committee when it's all going to be sorted out?

DR. WARD: Yes. Yes.

MEMBER WALLIS: Yes?

DR. WARD: Yes, it should.

MEMBER WALLIS: Next week?

CHAIRMAN DENNING: That's next week.

DR. WARD: Yes, it should. They've got the calculations all finished, I just haven't seen them. I just want to -- I have convinced myself that this works. And I'm comfortable with it. I understand it, did the calculations.

MEMBER WALLIS: But it's up to them to

show you.

DR. WARD: But it's up to them to do it and it's up to them to make sure that it works with their model. And they have said that they're getting the same response that I've got for these breaks. It's for the breaks they can't flush, the refilling for the bigger breaks, they're depressurizing and they're flushing the core.

DR. BANERJEE: Tell us the differences that were there before you started to rationalize it. What were you seeing and what were they seeing?

DR. WARD: Well, I wasn't seeing anything from them. I wanted them to do this. There wasn't any analysis of this at all. This was a question I had, hey, you guys got to look at small breaks, too, because you've either got to cool it down and flush it or you got to refill it. And I want to see those calculations. And they did that.

DR. BANERJEE: Okay.

MR. HARTZ: Yes. This is Josh Hartz of Westinghouse.

Dr. Ward did some hand calculations that cast some concern on the depressurization aspects under small break LOCA long term cooling. We have since gone off and done some runs in NOTRUMP space to demonstrate you can get down to a low pressure to the point where you can provide RHR flow to mitigate the boron precipitation here in a timely manner.

And also in speaking for Dr. Ward, he has since done RELAP calculations which basically show the same thing. And we're in the process of validating those calculations and they'll be done within the next few days, the official review of them.

DR. WARD: I'm going to show you the results of a 1, and a 2 and a 3 inch break in the cold leg. And you can boil for a while here.

This is RCS pressure versus time and you can see the smallest break here is the 1 inch break. It hangs up on a pressure plateau. That's because the break is not big enough to depressurize the system. You need heat removal through the generator. So a delta T will develop between the primary and the secondary. You are condensing steam here. You are refluxing. And it's holding the pressure above the secondary side, which is probably around 1100, somewhere, a 1000. At one hour open the atmospheric dump valves, cool this plant down. And cool down. And then at about a little over an hour and a half, maybe just under two hours, you can see this little blip there. And I should have blow this. I apologize.

But what happens here is it refills. And if I plot the void fraction in the core, you will see it go up and it will go to zero right at this time.

Now, if I look at a little bigger break, a 2 inch break --

DR. BANERJEE: Is there any core uncovery during that refluxing?

DR. WARD: Yes. For the 2 inch -- it's in the short term. It's back. It's occurring back -- well, it would occur back in here. Now remember that analysis that you saw for short term doesn't assume any cool down. So if you cool down, you've probably got to limit the amount of uncovery and it's recover fast. So the temperature is probably going to be a little lower.

But we're looking at boron precipitation and getting down here. And the procedure now says cool this plant down at an hour. And so what that does is the one inch refills at about 7,000 seconds. Just under 2 hours.

The 2 inch, and see I stopped it after refill. It refilled right here. So it's a little bigger break, take a little bit longer to refill. But it repressurized and it's resubcooled, void fraction went to zero right here in the core.

And then I said let's run the 3 inch, what happens with that guy. And, of course, he depressurizes a little faster because the break's big enough to -- you get steam out the break and you depressurize real early. But that refills out here around 17,000 seconds. And you can see the void fraction in the core go to zero right about there.

And if I look at a 4 inch or bigger, I'm down below 100 pounds in the real low pressure range where the high pressure pump is going to flush it.

DR. BANERJEE: Then let me ask you something. You get significant periods of concurrent flow here, right?

DR. WARD: Yes, that's right.

DR. BANERJEE: In your opinion how does NOTRUMP calculate concurrent flow?

DR. WARD: Well, it looks at the junction connected from the hot leg to the generator. And it looks at the steam flow going up and it says if the steam flow is greater than a JG that says no liquid goes down, then it doesn't allow liquid to go down. I think the drift velocity model is solved such that if you're in that flooded region, only steam goes up and no liquid will come out.

DR. BANERJEE: Can you get counter

currents.

DR. WARD: Yes, you can. If the steam velocity is low enough, you can have -- for this transfer -- small breaks typically you don't see the water hold up for these 2 and 1 and 2 inch breaks because there's not enough steam flow. You're far out in time. There's a large area there. So there's just not enough of a flux to hold it up.

With these power uprates though, you asked a good question. You're starting to see higher steam rates. And they did see some hold up. And I saw that. We asked them hey, what happens if you don't hold it up, you let it drain out or carry it over. And Josh did some calculations where he let it drain it out.

If you let it drain out, then the core uncovers later and not as deep because it's in a lower decay heat span. Because the code was calculating some water hold up, once the core uncovered, you can see once it got down to about 50 percent, 60 percent uncovery, the steam rate dropped off. The JG was too low and liquid started to drain out. What it did is it recovered the two phase level. But it turned out that the early uncovery, even with that slight recovery, that's still worse than throwing it on the other side or letting it drain out. Because what it does is it throws the uncovery out farther in time when the decay heat is lower, so that's not as limiting.

MR. HARTZ: Yes. Plus there was a little bit of a extended period of two phase low quality mixture coming out the break in the cold leg there, which tended to drive mass loss up.

DR. WARD: Okay.

DR. BANERJEE: And RELAP5 isn't great at this flooding calculation either. Because, you know, the problem -- we can discuss it off line.

DR. WARD: Okay.

DR. BANERJEE: But it's long known that the interfacial drag correlation has difficulties in this region.

DR. WARD: Yes. Could be.

DR. BANERJEE: Way back --

DR. WARD: Yes.

So what this really says is it really emphasizes operator action. I mean to control boric acid you have to cool -- in order for this refill to occur, you have to initiate a cool down at an hour. And the licensee has agreed to emphasize or make sure that it says start your cool down no later than an hour. Because it's important to depressurize and get the pressure down and flush it as early as -- you don't want to sit there boiling for long period of time because if you did, let's say a dump valve failed -- and that analysis I did I'm going to point out there are four dump valves. I failed one of them and I failed the HPSI part; that's a multiple failure event and it still worked.

What this says is that they need to be very aware of there are other depressurization capabilities. And they have to PORVs as a backup. Plus four dump valves. There's one on each generator and then there's a common one on the main steamline for both units. And they're a huge capacity.

So really what this says is the EOP guidance is really important and the equipment you use to cool down. And make sure that you can control boric acid for small breaks is important. And all they need to know is when the break opened and they switched to simultaneous injection at 6 hours, that's all they need to know about. But they need for small breaks to be successful, you need to cool down no later than an hour. If you're going to wait longer then -- the scenario is going to change. The other thing is you don't also caution -- there's going to be a caution in there, I think this is part of their training program. And if your boiling for extended period of time, let's say you're out eight to ten hours. And since the pressure in those cases is up pretty high, the precipitation limit is up like 50 percent. So the 6 hour doesn't apply. I can sit there and boil for a while. But you don't want to do that because if you get power back, you don't want the operators crashing the pressure down when you've got 40 weight percent in the system. So it's important to cool down and get this thing refilled and flushed as early as possible.

And the calculations show that you can do that. Even with a multiple failure event you can do it. At least I'm convinced of it. And I think Josh and Westinghouse has done the calculations to also show that.

So the EOP, this review had done a couple of things. It's identified a worse break. We got rid of the integer break spectrum.

They were assuming all the loop blown. Now that's not their approved model. Had them rerun it again with only assuming the broken loop seal clears, and that's what we approved. And they did in order to compensate for the very high PCTs. Probably PCTs over 2200, they increased the accumulator pressure to 625 to keep it down around 1900. So from a safety standpoint, that's a good thing to do. Now they'd already increased the HPSI flow 5 percent. That's also from a safety standpoint a good thing to do.

But then the Staff calculations on boric acid precipitation for small breaks also enabled us to emphasize the need for the EOPs and have the operators cool this thing down no later than an hour and be very sensitive to the depressurization equipment that they have. And not to inadvertently depressurize the system if you for some reason boil for 8 to 10 hours. And even if you're up there around 100 pounds to 200 pounds pressure, boiling for 10 or 15 hours, it's in solution. You've got 55 weight percent for probably a limit. But your accumulating too much boil. You don't want to sit there too long. The emphasis is get the thing down and get it refilled.

CHAIRMAN DENNING: I'm missing as far as whether you made recommendations for EOP actions that haven't really been implemented yet relative to this timing of cool down?

DR. WARD: Right. The vendor needs to EOP guidance that's consistent with their analyses that shows in order to refill the system for these small breaks, you need to initiate a cool down no later than an hour. Don't boil for long periods of time because you can get --

CHAIRMAN DENNING: You say "initiate a cool down." Where do you have to be when?

DR. WARD: Well, you start -- remember I showed you the calculation. Right here. One hour.

This analysis, the refill for these breaks and you flush this. It's based on cooling down at one hour. If you come out here, I mean you're going to be boiling for a longer time, you're going to build up more boron. It's probably not a good thing to sit there boiling for a long time building up a lot of boron because you put yourself in a situation where if you get power back out here and then you decide to open the turbine bypass and crash -- let's say you could crash the pressure down, you could cause a precipitation. You don't want that to happen.

You want to cool it down. Start the cool down early and get it refilled and disperse the boron so you don't have these large amounts of boron in the system.

MR. HARTZ: This Josh Hartz from Westinghouse again.

The way the EOP guidance is currently written this would occur. In fact, it would occur sooner than that. What Len's analysis is showing that if you start to cool down at one hour, the boron precipitation concern as analyzed here really isn't a concern.

Estimates from the Operations folks show that this cool down would actually start somewhere between 30 to 40 minutes into the transient. And that's the way the guidance is currently.

And Pete with his Operations experience can maybe add something to this.

MR. SENA: Yes. This is Pete Sena.We ran the Operations crews both units through simulated small break scenarios, various spectrums of small breaks, using existing EOP guidelines. And the crews were able to initiate the cool down with the existing network within 30 minutes.

I personally ran it and with one signal operator, assuming one operator was incapacitated. And the cool down was initiated within 24 minutes.

So with existing guidelines we can satisfy the one hour requirement that Len has identified.

DR. WARD: A couple of other things here, too, I'd just like to add.

There's some other depressurization mechanisms that we didn't even account for. And one would be using pressurization ox spray if the power operator relief valves on the pressurizer were not available. We did not credit that.

And also for these smaller breaks which don't depressurize, like I discussed earlier you do go through a single and two phase natural circulation period. Typically for these breaks that's on the order of anywhere from 1,000 to 2,000 seconds. During that time frame everything within the reactor coolant system is homogenous. And so these boil off calculations would really start after that mechanism breaks down.

We assume that that starts at time equal zero. And so if the calculations has truly took that into account, the actual hot leg switchover time would be extended well beyond what is being calculated here, not accounting for that.

DR. BANERJEE: But the RELAP5 calculations automatically should take natural circulation and break down of natural circulation into account.

DR. WARD: They did. They did. They have that in there. That's built it. That's built it.

DR. BANERJEE: So I mean that's automatically taken --

MR. LASH: Yes, it's in there.

DR. BANERJEE: --into account then.

DR. WARD: Right. You're right. That's correct.

MR. HARTZ:

Well, they do for the depressurization aspects, but for the boric acid precipitation calculations they do not because it's a different model.

DR. WARD: Yes, that's a different model.

DR. BANERJEE: But you could incorporate boric acid into your -- as a scale of field, right?

DR. WARD: You could. And then you get diffusion problems. You know, you got to make sure that -- all over these cells.

DR. BANERJEE: Because of your --

DR. WARD: Because of the first order -- difference on the --

DR. BANERJEE: On the cells.

DR. WARD: You know, so I got to go through and got to do a third order and then I got to a put -- boy, that's a pain in the you know what.

DR. BANERJEE: Yes. So the scale equation would have to be solved --

DR. WARD: That's right. That's right. Right.

CHAIRMAN DENNING: You done?

DR. WARD: Yes, I'm done. So I guess I

don't -- unless you have any questions.

CHAIRMAN DENNING: Thank you.

DR. WARD: Looks fine.

DR. BANERJEE: You do that in any case, you know.

DR. WARD: Yes.

DR. BANERJEE: You could with a lot of these issues?

DR. WARD: I could, yes.

DR. BANERJEE: It's not such a big deal.

CHAIRMAN DENNING: And now we're going to have a discussion of containment from NRR.

To the extent that there is some repetition, go quickly.

MR. LOBEL: Yes, there's a lot of repetition.

Good afternoon. My name is Richard Lobel. I'm a senior reactor systems engineering in the Office of Nuclear Reactor Regulation. I'm here today to discuss the Staff review of the FENOC proposal to convert the Beaver Valley Unit 1 and Unit 2 containments from sub-atmospheric to atmospheric containment designs.

The licensee performed the analyses to support the containment conversion at extend power uprate conditions. So the Staff's review of their containment conversion also serves as the review of the extended power uprate.

A lot of what I was going to say has already been discussed, so I'll try to go through it or skip parts of it.

Next. Okay.

February 6, 2006 there was an NRC letter to FENOC that approved the conversion of the Beaver Valley Unit 1 and Unit 2 containments from sub-atmospheric to atmospheric. And as part of that proposal, part of the original proposal the licensee included consideration of extended power uprate and the Unit 1 steam generator replacement. Also the licensee used the new analysis method, MAAP-DBA.

Next slide.

Beaver Valley units aren't the first power plants to convert from a sub-atmospheric to an atmospheric containment. Millstone Unit 3 is a 4 loop Westinghouse designed reactor that was originally licensed as a sub-atmospheric containment in 1986 and in 1990 the licensee for Millstone proposed converting from a sub-atmospheric containment to a higher pressure but still with a vacuum, but the design basis was changed to that of an atmospheric containment, which is pretty much what Beaver Valley has done. And the staff approved the Millstone Unit 3 proposal in January of 1991.

I think I'll skip this one. The licensee already talked about the pressure ranges, that they're increasing the pressure in the containment but it'll still be operated from 12.8 psia to a very slight vacuum. The licensee added a lower temperature limit in the tech specs also that limits the mass of air in the containment for a given pressure that's important for the pressurization calculations.

Next slide. Let me just say that this is the sub-atmospheric containment design bases which were the design bases for the Beaver Valley containments before the conversion. And the design bases that are italicized are the ones that changed.

For sub-atmospheric containment the requirement is to depressurize after a LOCA in one hour and once depressurized to stay sub-atmospheric for the rest of the accident. And that has a direct impact on the dose calculations once the reactor is depressurized again, they don't have to assume leakage from the containment for dose calculations.

For the atmospheric containment design, the other design bases remained the same, but the ones of concern, the sub-atmospheric containment, were replaced by one that says that the containment pressure should be less than 50 percent of the peak within 24 hours. And the reason for that is that helps in the dose calculations because when the pressure is less than 50 percent, the guidance for dose calculations states that the containment leakage can be reduced by half after 24 hours.

CHAIRMAN DENNING: What do you mean "minimum containment pressure greater than 8 psia." It's just at that initial time when they need credit?

MR. LOBEL: For the atmospheric containment -- no, they calculate a peak pressure and then they demonstrate that within 24 hours the pressure is reduced to 50 percent of that peak pressure.

CHAIRMAN DENNING: Your fifth bullet right there.

MR. LOBEL: Oh, that's really a requirement for reverse pressure on the containment that the pressure on the outside of the containment could be larger than the pressure inside the containment. And --

MEMBER WALLIS: Is it collapsing the containment you're worried about?

MR. LOBEL: Yes. And there's a structural requirement for that. And that's demonstrated by assuming an inadvertent actuation of the containment sprays and that the pressure won't go down below 8 psia.

CHAIRMAN DENNING: But clearly you'd have to lose an awful lot of air for that to happen in this containment?

MR. LOBEL: Well, you start with a low pressure and then you make very conservative assumptions about the temperature of the sprays and that kind of thing.

CHAIRMAN DENNING: Okay.

MR. LOBEL: It's a very conservative hand calculation.

The large break LOCA I think you've pretty much gone through, or the licensee pretty much went through with that. Let me just say that the calculations for the mass and energy release were done with NRC approved Westinghouse methods for less than one hour. For greater than one hour the mass release was calculated with the same NRC approved Westinghouse methods. The energy was calculated with the MAAP-DBA code.

We had some questions about separating the calculation of the mass and the energy between two separate codes. So Veronica Klein, who is still here, did some calculations for us with the RELAP code that essentially verified that we got almost the same results the licensee did with separating the two calculations. And so we found that their approach was satisfactory.

You've already seen the LOCA results. I won't go through that again.

For the main steamline break, the mass and energy release calculations were done with Westinghouse approved methods. The licensee modeled the replacement steam generators, the cavitating venturies. Since it's difficult to tell what size break and what power level they're limiting for main steamline break, the licensee did a spectrum of breaks and power levels. And made conservative assumptions, the -- failure and other conditions that maximize the inventory in the steam generator and the stored energy in the steam generator.

One of the important parameters from the main steamline break calculation is the liner temperature. The LOCA gives the peak containment pressure, the main steamline break is the highest temperature. The acceptance criterion for the containment liner was 280 degree. And the licensee calculated temperatures lower than that with conservative assumptions. For instance, the heat transfer coefficient between the containment atmosphere and the liner was multiplied by a factor of 4 that's consistent with the Standard Review Plan.

Now for over pressure and NPSH. The Standard Review Plan Section 6.2.2 for sub-atmospheric containment allows credit for containment accident pressure for available NPSH during the injection phase of the LOCA. At the pre EPU power level for the sub-atmospheric containment Beaver Valley Unit 1 credits containment accident pressure calculating the available NPSH for the recirculation spray pumps and the low head injection pumps. And this was part of the original licensing bases.

At the pre-EPI power level in the sub-atmospheric containment Unit 2 doesn't credit containment accident pressure. At the extended power uprate conditions conversion on the atmospheric containment, the containment accident pressure is credited for Unit 1 for the recirculation spray pumps not for the low head safety injection pumps. That's based on changing the timing of the actuation of the low head safety injection pumps.

Unit 2 at extended power uprate with the containment conversion still doesn't need credit for containment accident pressure.

Let me see. I think they went through the basic reasons. Basically for Unit 1 the recirculation spray pumps start at a time when the level in the sump is still relatively low and the temperature of the sump water is relatively high and due to the placement of the pumps in Beaver Valley 1, that's what requires credit for containment pressure. And we queried the licensee about what would happen if you did a realistic calculation and not a conservative calculation. And they say that due to those factors they would still need credit for containment accident pressure.

CHAIRMAN DENNING: I wasn't sure I heard that earlier. Is that basically the position of Beaver Valley that for realistic calculation with uncertainties, not suggesting that you would do that, but is that your feeling that -- did you hear that fifth bullet?

MR. LOBEL: We asked that question in a formal RAI.

CHAIRMAN DENNING: In a RAI. So it get a formal answer.

MR. FREDERICK: Ken Frederick.

In looking at a better estimate analysis the parameters that we can vary towards more best estimate do not directly impact the sump temperature to a degree where we could get rid of the requirement for containment over pressure. There is some benefit there, but it's not enough to get rid of the requirement.

CHAIRMAN DENNING: Thank you.

MR. LOBEL: Next.

This is similar to the curve that was shown before, and it's a curve for the worst case of the containment pressure actually in terms of overpressure versus the pressure that's required for adequate NPSH for the inside and outside recirculation spray pumps.

Again, this is in terms of overpressure so you're looking at their definition of overpressure which is the calculated containment pressure above the initial containment pressure.

And you can see that this is for the first case, that they don't need the credit for a very long time and there is margin to a conservatively calculated containment pressure.

The difference between the peak pressure in this case and the minimum pressure is really less than it was last time I was here talking about Vermont Yankee. There was a lot larger difference. But the licensee submittal was very good with respect to talking about the input parameters that went into this and sensitivity studies they did. And there's a table in the Jun 2, 2004 letter, it's table 4.3 where they have a list of the significant variables and sensitivities that they've determined for the different cases and for NPSH they assumed values that were in the most adverse direction for calculating NPSH.

So judging from that, we're convinced that the calculation is conservative for a minimum pressure.

The next curve you've also seen before, and I think that had a pretty good explanation so I won't go through that again. But, again, I think the important point is in terms of containment integrity. For the largest assumed hole between the inside and the outside of containment, the largest penetration that connects the inside atmosphere to the outside atmosphere if I assume that that's open, I still maintain some NPSH margin.

Next slide.

There is a 1977 report which was submitted to the NRC where there was some testing of a recirculation spray pump for North Anna Unit 2. You saw the NPSH curves for it before. And the central point, again, was that this pump was tested in cavitation at different levels and then run for half an hour at a significant amount of cavitation well below the 3 percent usual required NPSH value. And there was essentially no wear and no damage to the pump.

So in conclusion for this part, the Staff accepted the licensee's proposed credit for containment accident pressure in defining available NPSH for the recirculation spray pumps based on several reasons.

First, containment integrity is assumed for postulated designed bases accident, in particular as I've said before here, Appendix K permits the use of conservatively minimized containment pressure in determining peak cladding temperature and oxidation limits. And also offsite and control room dose calculations assumed containment leakage at -- which is a very large leakage value of containment that's specified in the technical specifications. And that low leakage rate also assumes containment integrity.

Furthermore, the licensee's study shows, as I just said, that for the largest penetration directly connecting the inside of containment to the outside of containment, that there would still be sufficient NPSH margin.

The Beaver Valley containment pressure during normal operation would be slightly sub-atmospheric. That's a tech spec requirement. And therefore, any significant leakage in containment should be detected.

Also credit for containment accident pressure is applied for a relatively short time in the case of Beaver Valley. And as I just said, also the Beaver Valley pump tests that demonstrated that the pumps can operate with some level of cavitation for a longer time than they would need to according to these conservative calculations without experiencing any damage or wear.

And finally, there's no impact on the emergency operating procedures of crediting containment accident pressure.

MEMBER MAYNARD: I would agree with a caveat that containment operating at a vacuum doesn't always guarantee that there's no leak path when it's pressurized. But I do agree with the overall conclusion.

MR. LOBEL: It's sort of like the argument that I was making for Vermont Yankee, which was an inerted containment. That it's just another factor.

MEMBER MAYNARD: Yes.

MR. LOBEL: And it depends on the size of the hole.

MEMBER MAYNARD: And the characteristic. A check valve will stop flow one way but not another way.

MR. LOBEL: Right.

MEMBER MAYNARD: A minor thing.

MR. LOBEL: Right.

MEMBER MAYNARD: Not a direct correlation.

MR. LOBEL: I think part of this review was actually the review of the MAAP-DBA code. The licensee actually made a presentation to ACRS to the Thermal-Hydraulic Phenomena Subcommittee back in November of 2001. And since then the Staff and the licensee have had an interaction talking about the various proposed models in the code. The licensee submitted a description of MAAP-DBA in November of 2003 in a letter to the NRC. And there's another description of the code in the licensee's containment conversion submittal.

MEMBER WALLIS: When we saw, we had a lot of questions, didn't we?

MR. LOBEL: Right. There --

MEMBER WALLIS: We were expecting to see it again.

MR. LOBEL: There was some good questions that were asked. That version was called MAAP5. And the licensee revised the code based on the review that we did to MAAP-DBA where MAAP-DBA is more in line with the Standard Review Plan. MAAP5 had a lot of -- not a lot. Had some moderates that were kind of unique to containment analysis at the time. And as we went through the review process, we ended up with MAAP-DBA.

I really have a longer presentation on MAAP-DBA, but given the time constraints, I wasn't going to do very much. Of course, if you'd like to see more. I can't speak for the licensee, but we can come back, the Staff can come back and talk about it in more detail.

DR. BANERJEE: Can I just ask a couple of things about it.

MR. LOBEL: Sure.

DR. BANERJEE: Do you have some experiments against which it's been validated?

MR. LOBEL: Yes.

DR. BANERJEE: That's one.

MR. LOBEL: Separate tests and integral containment experiments.

DR. BANERJEE: And any other codes against which it has been compared?

MR. LOBEL: The licensee made comparisons and got pretty close agreement with GOTHIC6. GOTHIC is kind of getting to be kind of the industry standard for CONTAIN code. Are you familiar with GOTHIC at all? GOTHIC was developed by EPRI.

DR. BANERJEE: Yes.

MR. LOBEL: Developed for EPRI by Numerical Occupations, Incorporated. And it's an Appendix B code. It's subject to Part 23. And EPRI for ever new version that makes a significant version, basically the whole validation process in a lot more detail than vendors usually do for these kinds of things. They compare with a lot more data.

Most of the data that Beaver Valley used for the MAAP code was International Standard Problems. There's a German decommissioned reactor, HDR, that had a couple of standard problems. And some very old data that's still useful from a decommissioned reactor and the reactor in this country, CVTR that they compared with. And the comparisons were good.

DR. BANERJEE: This is the spray and all this sort of stuff?

MR. LOBEL: Right. With spray and without spray. There are some separate effects tests that were done with some Canadian data where there is, I believe, one nozzle on a five nozzle spray test in a steel vessel. But the first test was without the spray. So the licensee compared with the data without the spray and with the one nozzle and the five nozzles.

And also for some Japanese data, they did comparisons against data -- I'm trying to remember now if they did -- the Japanese tests were done with a single nozzle and with multiple nozzles. And the advantage of the single nozzle test was that the spray didn't touch the walls of the vessels. So it was strictly an interaction of the spray with the atmosphere without the effects of the walls and condensation and impacted the spray --

DR. BANERJEE: Has the NRC Staff had a chance to use this code and compare it with some experiment which it hasn't been validated against?

MR. LOBEL: Use the MAAP code? No. No, we haven't.

DR. BANERJEE: You don't have access to it to compare it with anything?

MR. LOBEL: Really didn't ask for access to it.

DR. BANERJEE: Okay. In other words, I'm always sort of worried that codes can be validated against data but once they're frozen and you compare them to a new set of data, they may not work so well.

MR. LOBEL: Well, back in the days when we were reviewing MAAP5 we did pretty extensive calculations to compare with MAAP5 using our CONTAIN code. We didn't use the MAAP code, but we used the CONTAIN code. And our Office of Research was involve din that review. And at a certain point in that review we decided when the licensee came in with MAAP-DBA, we decided that based on the changes that were made from MAAP5 to MAAP-DBA, that MAAP-DBA pretty closely followed the Standard Review Plan, the Tagami Uchida correlations and the same type of heat transfer correlations that are used in the CONTAIN code. And we made the decision that we didn't need to do anymore audit calculations.

DR. BANERJEE: Do you have any code available to you to do an independent audit?

MR. LOBEL: We have the CONTAIN code. Like I say, we used the CONTAIN code for the MAAP5 review.

We also have the GOTHIC code. We have--

DR. BANERJEE: GOTHIC6?

MR. LOBEL: Well, GOTHIC6 is what the licensee compared with. We have GOTHIC7.2, which is a later version. The latest version, I believe. So we have that code available to us also.

CHAIRMAN DENNING: To what extent is this operated in a best estimate versus a licensing kind of mode, isn't it? Don't you typically use it in a mode in which, depending upon whether you're looking for high containment pressure or low containment pressure and stuff like that, it's --

MR. LOBEL: Are you talking about MAAP?

CHAIRMAN DENNING: MAAP-DBA, the way it's used.

MR. LOBEL: A lot of the conservatism I think comes from the assumptions that are made, the input that's made. So you --

CHAIRMAN DENNING: Like Tagami Uchida I've always thought that those were very conservative correlations.

MR. LOBEL: Yes. Yes, they are. There's some disagreement about how conservative in comparing the data. But the Staff has always accepted those on the basis that they're conservative.

MEMBER WALLIS: They're conservative in what way?

CHAIRMAN DENNING: Node.

MR. LOBEL: But-- but -- but MAAP has other heat transfer correlations that they use. For MAAP, MAAP is used for single node and multiple node calculations. For the single node calculations which they used for the peak pressure and temperature and those things, they're done, it's Tagami and Uchida because the basis of deriving Tagami and Uchida was a single volume experiment. For the multiple node different heat transfer correlations are used that are more best estimate.

But then like I was showing for the case of the liner temperature, you know you can bias the results to either give a high heat transfer, a low heat transfer, high pressure, low pressure.

DR. BANERJEE: Perhaps the concern is that this core is being used in sort of an inverse way. Usually you are trying to be conservative with regard to how high the pressure is. I mean, most coded are tuned to do that. Now you're trying to be conservative with regard to how low the pressure can be.

MR. LOBEL: It's really just a function of the input. For instance, if I'm trying to predict a low pressure, I --

DR. BANERJEE: Lower limit?

MR. LOBEL: Lower limit.

DR. BANERJEE: Yes.

MR. LOBEL: Lower limit, a lower bound on the pressure, I'll assume that the containment starting pressure is low. If I were doing a peak pressure calculation, I would assume that the starting pressure is high.

MEMBER WALLIS: But how about the heat transfer coefficients?

MR. LOBEL: The heat transfer coefficients--

MEMBER WALLIS: Are they conservative one way or the other way?

MR. LOBEL: Right. Right. That would be another one.

MEMBER WALLIS: Which way are they?

MR. LOBEL: Well, for peak pressure --

MEMBER WALLIS: You'd use those?

MR. LOBEL: -- you would want to minimize the --

MEMBER WALLIS: Right.

MR. LOBEL: -- heat transfer. They say like for the peak pressure you want to minimize the heat transfer coefficient.

MEMBER WALLIS: Right.

MR. LOBEL: For the minimum pressure you try to maximize.

MEMBER WALLIS: Well how do you do that?

MR. LOBEL: How do you do that? Well, you can do it in several ways. You can minimize the heat transfer --

MEMBER WALLIS: You can make it zero. You can make the heat transfer coefficient zero.

MR. LOBEL: You could --

DR. BANERJEE: You could not do it in infinity --

MR. LOBEL: That's what the BWRs do.

MEMBER WALLIS: Right.

MR. LOBEL: They look at zero.

DR. BANERJEE: But you can't make infinity?

MR. LOBEL: Well, I --

DR. BANERJEE: Or can you?

MR. LOBEL: I haven't done the calculations, but I imagine there's probably a point of diminishing returns where it doesn't matter anymore.

DR. BANERJEE: Well, if the energy goes

through --

MR. LOBEL: Perhaps others can elaborate.

DR. BANERJEE: -- the containment. I mean, is it the conduction losses of --

MR. LOBEL: But that's pretty minimal the time we're talking about. The containment is a pretty stiff concrete structure. That's not a major concern.

DR. BANERJEE: So if it soaks up all the heat, the containment, then what happens?

MEMBER WALLIS: Limited by conduction into the wall.

DR. BANERJEE: Yes. Is the conduction limited then or is it convection limited, the heat transfer?

MR. LOBEL: Are we talking about peak or minimum or --

DR. BANERJEE: We're trying to establish a minimum pressure curve.

MR. LOBEL: Okay.

DR. BANERJEE: So if heat is now conducted into the wall of the containment --

MR. LOBEL: Right.

DR. BANERJEE: -- and we assume the containment is extremely well mixed, then the only resistance would be the conduction heat transfer. We can do a hand calculation, correct?

MR. LOBEL: Well, the big impact isn't the conduction into the containment. It would be the sprays. And especially --

DR. BANERJEE: Well, you turn that off, that heat transfer to get a minimum, right? Or is that--

MR. LOBEL: To get a minimum pressure? No, that's how --

DR. BANERJEE: Sorry. You want it all into the spray?

MR. LOBEL: Right. Right. The Standard Review Plan says for the LOCA analysis where you calculate a minimum pressure that all systems that can reduce the pressure have to be assumed to be operating and --

MEMBER WALLIS: To spray, the pumps have to work, so these --

MR. LOBEL: Fan coolers, containment sprays, maximizing the heat transfer to the structures.

DR. BANERJEE: Right. One would have to look through this and write down all the assumptions--

MEMBER WALLIS: That's what they did?

MR. LOBEL: Yes. Yes.

MR. FREDERICK: This is Ken Frederick.

MR. LOBEL: And that's in the table 4.3 that I was referring to before. If you want to look at that, But that lists two pages, that list of variables.

DR. BANERJEE: So if you now compare the code with the data, it always under predicts the data then?

MR. LOBEL: Well, when they do the --

DR. BANERJEE: It has to.

MR. LOBEL: -- calculations for data, they're trying to do a best estimate calculation because presumably that's what the data is. It's the best estimate.

DR. BANERJEE: But if you make corresponding assumptions that you did for these calculations with the data --

MR. LOBEL: If I made -- well, there are some studies that were done by the Staff. The Office of Research published some reports. We in NRR asked Research to look at the CONTAIN code and make some recommendations of how to use the CONTAIN code as a design bases code. And they went through and did sort of what you're talking about in those reports. They compared with data and then they made different assumptions to show that they would be above or below the data or how it impacted comparisons for the data. And I can give you those references, if you want.

DR. BANERJEE: So there is a set of comparisons with CONTAIN at least --

MR. LOBEL: Right. Right.

DR. BANERJEE: -- with the data where they always under predict the data given a certain set of assumptions?

MR. LOBEL: Well, I don't want to over sell it. I think I want to stick with what I said that just they compared with data and then did some sensitivities to see how different parameters effected the results. They weren't trying to do -- you know, minimize, get a lower bound compared to the data. But it's done primarily with codes like GOTHIC and MAAP and even CONTAIN is the assumptions you make on the input more than the models that are in the code itself.

MR. FREDERICK: I just want to add something here. This is Ken Frederick.

In terms of the multiple node analyzes which we were using for NPSH and over pressure calculations, that typically uses a natural convection coefficient. And as part of our sensitivity studies we did multiples by that. WE increased it by a factor of 4 or 5. And we don't see a whole lot of change based on that.

And one thing that becomes limiting for most of the heat sinks is conduction through paint and coatings actually become more limiting than the convection on the surface. So that's why it doesn't have a dramatic impact on the results.

DR. BANERJEE: So the limiting phenomena are conduction to structures in terms of --

MR. FREDERICK: For structures that are painted, yes.

DR. BANERJEE: So the --

MR. LOBEL: No. I think you have to understand what he was saying. For the structures, the paint is limiting.

DR. BANERJEE: Yes.

MR. LOBEL: But in terms of what minimizes the pressure, I don't think you would say it's the structure.

MR. FREDERICK: No. It's been effected by the heat transfer coefficient to a degree.

MR. LOBEL: Yes.

MR. FREDERICK: But you reach a point where it doesn't make any difference because conduction becomes limiting.

MEMBER WALLIS: So the sprays dominant in this circle, where if they work it means the pumps working and therefore everything is okay. So it's, you know, a self-correcting situation.

MR. FREDERICK: Right.

MEMBER WALLIS: That probably dominates everything.

DR. BANERJEE: Does the spray dominate everything?

MR. FREDERICK: Yes. Once the sprays come on, the heat transfer to the structures is relative unimportant because the sprays control the pressure.

MR. LOBEL: Especially for a plant like Beaver Valley that was sub-atmospheric, but there is sub-atmospheric containment because first of all there are three spray systems or two spray systems, depending on how you look at it. There is a quench spray system which is taking section from the RWST which for a sub-atmospheric containment is cooled. So it's not at assumed 90 degrees or a 100 degrees or whatever. It's down around 45 to 55 degrees for the quench spray.

And then there's the recirculation spray.

So you're putting an awful lot of water

into the containment atmosphere to lower the pressure because that's the way they were designed. They had to get down below atmospheric pressure in an hour. And that's the main way that was done with all the spray water into the containment.

So you have cooled spray water from one spray system and then two other spray systems that are spraying into containment.

DR. BANERJEE: Yes. I suppose the system is self-correcting, as Graham says. But leaving that aside for the moment, the voracity of MAAP-DBA with regard to establishing a lower pressure bound for the system, which is what we're looking for as opposed to an upper pressure bound which most of these codes are usually tuned to do, is sort of an issue which maybe you could just --

MEMBER WALLIS: Well, you're writing --

DR. BANERJEE: Yes, write a note or something which sort of establishes why we think that it's --

MEMBER WALLIS: You're writing new guidance on this whole issue, aren't you?

MR. LOBEL: In the Reg. Guide, yes.

MEMBER WALLIS: Can you come back to us with some of this other technical data, too, at that time?

MR. LOBEL: Sure.

MR. LOBEL: But I think the important point is that these newer codes, GOTHIC, CONTAIN which isn't a new code anymore, MAAP-DBA don't try to buy us things one way or another with the code itself as much as with the input data. So that gives the code more flexibility. I can use the same code to calculate peak pressure and minimum pressure. I just change the bias on the input, not the code itself.

DR. BANERJEE: Well, you'd have to demonstrate that that, that is true in some way.

MR. LOBEL: Well, I think if you look at this table, 4.3 in Attachment 1 to the June 2, 2004 report, the licensee did a pretty good job of listing the biases and a lot of variables for the NPSH calculation and for the peak pressure calculation, and for some of the other calculations. So if you go through that you can see how things were biased to get a certain result.

DR. BANERJEE: Sure. But that's a sort of a sensitivity study. But what would be, perhaps, more convincing would be in this note to compare it with data where you actually do the similar sort of thing. You bias the input. And show that you under predict the data or over predict it. And that would be convincing that the same methodology applies to data. I mean, if it applies to itself, you're just doing a sensitive study. We don't know about the voracity of the code at this point.

MR. LOBEL: No. Are you asking the licensee to do that --

DR. BANERJEE: No, no, no.

MR. LOBEL: -- or are you asking the Staff to do it without a code or --

DR. BANERJEE: I don't know. In this note where you're establishing guidance, perhaps --

MR. LOBEL: Then it's the Reg. Guide that you've been talking about.

DR. BANERJEE: Yes.

MR. LOBEL: I think that's what we're talking about.

DR. BANERJEE: The supporting data or whatever for a methodology would be to show that a sensitivity study on a code somehow done on a scenario related to a reactor is equivalent or is supported by some sort of sensitivity study done on data which establishes that this type of variation of input parameters truly establishes a lower or upper bound. I mean, the only thing we know is data at the end;

nothing else.

MEMBER WALLIS: It's usually not up to the licensee, though --

DR. BANERJEE: Yes. Well, but it is.

MEMBER WALLIS: -- and the NRC will approve a code based on comparison of the data, then it gets used.

DR. BANERJEE: And if this is methodology is established that, yes, we can vary the input parameters and this will give us a lower bound because I've compared it with all this data, we're sure of it, then we --

MEMBER WALLIS: Well there's been a guide which says you can do uncertainty analysis, so --

DR. BANERJEE: Somewhere here.

CHAIRMAN DENNING: Actually, I don't thin that -- I think really, Sanjoy, the way to do it is to validate your code realistically against data.

MEMBER WALLIS: Right.

CHAIRMAN DENNING: Once you have a code that you believe, then it's not that hard to play the games of changing the parameters --

MEMBER WALLIS: Right.

DR. BANERJEE: Yes.

CHAIRMAN DENNING: -- to under estimate or over estimate.

MEMBER WALLIS: The way to do it.

DR. BANERJEE: All right. If you can assume an uncertainty at this time --

MEMBER WALLIS: Right. Right.

CHAIRMAN DENNING: But let's move on now because I think we've spent enough time on this for the moment, I mean other than your conclusions here.

MR. LOBEL: I can go to my conclusion. Can we go to the conclusion, the last slide. Okay.

The Staff has issued the SER approving the conversion from sub-atmospheric to atmospheric containments for Unit 1 and Unit 2.

And also approving MAAP-DBA as part of the same review.

CHAIRMAN DENNING: Actually, go back one slide to the validation slide. Because we ought to at least look at that since that's kind of the focus of this discussion you had there.

MR. LOBEL: Okay. There was a comparison with GOTHIC6. There was a comparison for the mass and energy release for small break with the NOTRUMP code. We did some calculations comparing MAAP-DBA for greater than one hour with RELAP. Those were the code comparisons.

Like I say, for a previous review where it was a MAAP5 code, I think we did quite a lot of comparisons with --

MEMBER WALLIS: RELAP can model the containment?

MR. LOBEL: I'm sorry, what?

MEMBER WALLIS: Can RELAP model the containment?

MR. LOBEL: No. In that case we were doing mass and energy release calculations.

MEMBER WALLIS: Oh, I see. Okay.

MR. LOBEL: And for the NOTRUMP calculations that was comparing MAAP-DBA to NOTRUMP for mass and energy release calculations.

There were separate effects tests were done, condensation and spray tests. And then the integral test I talked about. The Canadian spray test, Japanese spray tests. There was the CVTR which stimulated a steamline break without sprays and with sprays. There is the HDR, which is a German reactor which doesn't look anything like a U.S. reactor, but there are international standard problems from that that the license compared with. And all those comparisons were pretty good.

CHAIRMAN DENNING: Thank you. And you're

done then?

MR. LOBEL: Pardon?

CHAIRMAN DENNING: You're done now?

MR. LOBEL: I'm done.

CHAIRMAN DENNING: Thank you very much.

Okay. Now we're going to hear about source terms and radiological consequences. And this is another presentation I think can really be pretty brief.

MEMBER WALLIS: Yes, let's move it along.

CHAIRMAN DENNING: Let's try to move quickly.

MEMBER WALLIS: Well, must give us some presentation and we'll listen.

MR. PARILLO: Good afternoon. My name is John Parillo. I'm a health physicist with the Accident Dose Branch in the Office of Nuclear Reactor Regulation. I'm here to --

CHAIRMAN DENNING: Mr. Parillo, speak into the microphone.

MR. PARILLO: All right.

Good afternoon. My name is John Parillo. I'm a health physicist in the Accident Dose Branch, and I'm here to discuss the source terms and radiological consequences analyses.

The first part of the discussion refers to the source terms for input into radwaste management systems. So basically how does the EPU effect the normal operations. This is covered in EPU Section 2.9.1 of the SE.

Basically what you do here is just evaluate the radiological source term in the reactor coolant for the EPI conditions, the power uprate. And the evaluations performed show that the source term continues to meet the requirements of 10 CFR Parts 1, 10 CFR Part 50, Appendix I and General Design Criteria-60.

The next portion of the discussion involves the design bases accident radiological consequences analyses. Again, this is covered in section 2.9.2 of the SE. And the licensee has implemented the alternative source term in all of the radiological analyses performed. For the actual EPU submittal, the analyses that needed to be looked at were the fuel handing accident because of an increase in fuel inventory and the main steamline break and the steam generator tube rupture for Unit 2 only due to change in mass release. All the other design bases accidents have been previously approved, and I'll go through that a little bit later.

For the radiological consequence analyses, the EPU power -- the power level evaluated was 2,918 megewatt thermal. And this represents a 100.6 percent of the rated power of 2,900. And this is based on the approval of a 1.4 percent measurement uncertainty recapture uprate.

And we also wanted to mention the NRC Staff performed an onsite audit of the radiological analyses supporting both the steam generator replacement license amendment request as well as the EPU.

Other DBAs have been evaluated as part of a selective implementations under 10 CFR 50.67. The loss of coolant accident and the control rod ejection accident were evaluated, Amendments 256 and 139 which were issued September 10, 2003.

The locked rotor accident and the loss of AC power and the small line break outside of containment for both units. And the main steamline break and the steam generator tube rupture accident for Unit 1 only. All those accidents were evaluated in Amendment 273 for the steam generator replacement issued February 8, 2006.

Put up a slide that concerned the control room. The evaluations for Beaver Valley and for those accidents in the EPU, the control room emergency ventilation system is credited for the main steamline break. They credit a pressurization mode, as it says, 500 cfm filtered intake. And during that period the license is assuming 30 cfm of unfiltered inleakage. And the licensee performed tracer gas testing which support the unfiltered inleakage assumptions.

For the accidents discussed here, the licensee credits a control room purge, a post-release control room purge. And in order to do that they credit the control room emergency air cooling system. And this system is credit for post-release purging for the steamline break, the steam generator tube rupture and for the Unit 1 fuel handling accident. Again, at the times when those releases are assumed to have ended.

The purge credit was not needed for the Unit 2 field handling accident because of more favorable meteorology for that particular half.

And basically the design bases accident rate radiological consequences, the licensee has adequately accounted for the effects of the proposed EPU and all the design bases accidents meet the 10 CFR 50.67 and Standard Review Plan 15.0.1 dose acceptance criteria for both offsite and the control room. And the Staff finds the proposed EPU acceptable with respect to the radiological consequences of design bases accident.

CHAIRMAN DENNING: Well, thank you very much for a focused presentation.

Do you have a question.

MEMBER KRESS: Yes. Here the source term you're talking about, the AST, the source term into containment, did they then use the MAAP code to subsequently get the release to the environment and the transport to the control room?

MR. PARILLO: No. The guidance in the Standard Review Plan pretty much is a cookbook. It dictates the percentage of the radionuclides that are released to containment. And the codes that are used for radiological analyses are not quite as sophisticated. They don't need to be. They're just volumes. So you start with so much activity in this volume and it leaks into another volume and eventually to the environment, and then leaks back into the control room. So we don't use the MAAP code.

The licensee, their calculations were done with Stone & Webster proprietary code, but we did confirmatory analyses with the RadTRAC code, which is the code we use at the NRC for these types of analyses.

CHAIRMAN DENNING: Okay, Tom. You happy?

MEMBER KRESS: No, but that's all right.

CHAIRMAN DENNING: Are you done?

MEMBER KRESS: Yes, I'm done.

CHAIRMAN DENNING: Okay. Thank you very much.

MR. PARILLO: Okay.

CHAIRMAN DENNING: Okay. And now we're going to hear about materials and reactor vessel integrity from FENOC.

MEMBER WALLIS: Just please start when you're ready.

MR. WEAKLAND: All right. My name is Dennis Weakland. I'm been with Corporate Materials for 3 or 4 years. Prior to that I've had 24 years experience with Beaver Valley primarily in the areas of materials inspections, analyses and the like at Beaver.

I've also been very active in the industry initiatives in materials -- owners group.

What I'd like to talk about a little bit on the materials construction, the integrity programs that we have, the Alloy 600 management and the vessel integrity.

The reason I emphasize the Alloy 600 and vessel integrity is I think these are the areas that are most important with the EPU uprate. And we'll discuss those in a little greater detail.

Our basic materials construction our reactor vessel, our steam generator and pressurizer are carbon steel vessels clad with stainless steel. Penetrations in these areas are stainless steel with a few Alloy 600 penetrations primarily at Unit 2.

RCS loop piping is Cast SS material. This is a really robust material in the RCS areas dealing with things like boric acid are not an issue. There is some concerns in license renewal license extension space as far as thermal embrittlement. Areas of that are not within the current license life.

And the balance of the RCS piping in both units is stainless steel, again robust material, high fracture toughness and not subject to boric acid corrosion.

The vessel components and welds are primarily stainless steel. A few at Unit 2 for Alloy 600, and I'll touch on those a little bit later.

So in general the Westinghouse design with a combination of the Cast SS, the stainless steel really provides a pretty robust RCS system to minimize the number of vessel and component welds.

The investment integrity programs we have, the steam generator integrity program complies with the 97.06. We've adopted it at Beaver Valley. It performs operational assessment at every outage. So the effects of the EPU, and since there's virtually no change in the hot leg anyhow from 609 to 609.5, we expect a little change. But we did do an operational assessment coming out so we know the status of everything coming out of every outage.

The Alloy 600 program we complied with the industry standards, primarily MRP 126 and 139.

The boric acid program is run under the WCAP which is the industry program 15.988. And we're adopting the material degradation program under NEI or 308 initiative to have an integrated materials program on our site, and those will be effective come June 1st this year in accordance with our 308 and the NEI initiative.

Together with the other operational programs we have and systems programs and things like system engineering routinely test our systems, our maintenance rule operational tools, BVTs that we run, we have a very good handle on the integrity of our systems and minimize the amount of damage. We see anything occurring, it's back into the system, repairs do occur and we address the issues while they're small.

So, as you see, we take these programs as a whole. We ensure the system integrity is maintained and degradation issues are identified at our earliest possible times and take appropriate mitigative actions.

This carton I thought was appropriate because it kind of covers both units. The basic RCS is the same. And right here these surge nozzles are only in a tube that are Alloy 600. Unit 2 has the vessel piping along with an Alloy 600 weld that we'll have to address. And the balance of this is all 315, 309 type material. So we have very, very limited amounts of Alloy 600 material.

The recent outage we've replaced all the Alloy 600 material at Unit 1 in the top of our head, taken it out of the picture, mitigated it and gone to 690.

At Unit 1 all the Alloy 600 materials in the steam generator at Unit 1 have been removed and are now 690. And at Unit 2 that will be managed under the existing program.

MEMBER WALLIS: 690 is a pretty new

material, isn't it? We don't really know what the problems are with it yet?

MR. WEAKLAND: No. The information that we have from the industry looking at the Naval reactor information and overseas information on 690 appears to be extremely robust. We can't put on a number on what it is. So as a result, the testing protocols that are done by the industry in 03.009 will continue the timing models and the Uranus equations that are used for Alloy 600 as a very conservative measure. As more is learned, those may be relaxed. But currently we would follow the same protocols.

DR. BANERJEE: So there is information on exposure to boric acid and everything for 690?

MR. WEAKLAND: 690 is used widely within the nuclear Navy in the borated systems.

DR. BANERJEE: And no problems?

MR. WEAKLAND: And they're robust. And 600 to the best of our knowledge.

MEMBER SIEBER: Navy plants are correlated, are they?

MR. WEAKLAND: Not the Navy, but the Alloy 600 testing, there's Alloy 600 testing to 690 that's been done at Westinghouse Labs and whatnot has shown no issues with the nickel based alloys as referred to

Alloy 600 and boric acid.

The austenitic materials 316, 309 when it comes to Alloy 600, you have very little problems.

DR. BANERJEE: So 690 is used in the Navy but the Navy uses borated systems or not?

MR. WEAKLAND: No, no.

MR. KAMMERDINER: This is Greg Kammerdiner from FirstEnergy.

As far as industry experience with 690, at least in steam generators, Indian Point 3 was the first one to switch to 690 in 1989. So we have quite a bit of experience from that date forward with 690 both domestically and internationally prior to 1989. I think Ringhalls was the first one to replace a steam generator with 690. And those steam generators have basically performed degradation free since the late '80s with 690.

MR. WEAKLAND: The next slide we cover the head inspections that we're doing at Beaver Valley Unit 2, which is mainly 600 material and these are the two heads at the two units. And this coming fall we'll doing -- well, the past fall, the fall of '03 we did bare metal visuals, found no degradation and volumetric of CDRM and J-welds, did an Eddy current examinations of the outside and no degradation.

In the spring of '05 we repeats in accordance with your order the bare metal visuals and we have volumetrics coming up this fall at the same unit for ongoing evaluations of the head inspections.

At Beaver Valley Unit 1 we've taken a very active approach on the mitigation of the Alloy 600. As I noted, we replaced the head, the steam generators and I just completed 1R17 outage this spring. This next fall we're planning on doing a weld overlay on the pressurized nozzles, which are the 600 dissimilar metal welds that we have to top the pressurizer. So we'll mitigate those, put them in a compressive state and we will continue to monitor them in accordance with the industry guidance.

MEMBER SIEBER: Do you have any indications on the places where you're going to do the weld overlays right now?

MR. WEAKLAND: No.

MEMBER SIEBER: So this is a preventive --

MR. WEAKLAND: Preventive overlay, yes.

MEMBER SIEBER: Okay.

MR. WEAKLAND: We're planning the same kind of preventive overlay in Unit 2.

MEMBER SIEBER: You're going to compress the fitting?

MR. WEAKLAND: Correct.

MEMBER SIEBER: Okay.

MR. KAMMERDINER: Again, this is Greg Kammerdiner again.

Besides inducing a compressive stresses, will be full structural overlays also. So it's a double measure here. Inducing the compressive stress on the existing 82/182 weld material plus full structural overlay of 690 on top of that.

MEMBER SIEBER: Well, if you're going to have problems, that's a good place for you to have them.

MR. WEAKLAND: They would be the likely suspects?

MEMBER SIEBER: Yes.

MR. WEAKLAND: Right.

The remaining Alloy 600 therefore at Unit 2 would be limited to the BMNs, the bottom mounted instrumentation. We'll continue to inspect those in accordance with the industry guidance. And then the reactor vessel internals, there's some Alloy 600 in there that we'll be addressing.

CHAIRMAN DENNING: Now to a large extent what you're talking about is not necessarily related to power uprates.

MR. WEAKLAND: No.

CHAIRMAN DENNING: As far as power uprates are concerned though there is some temperature increases--

MR. WEAKLAND: Slight temperature increases. Unit 2, that half of degree is virtually nonexistent in the space.

CHAIRMAN DENNING: Yes.

MR. WEAKLAND: Unit 1 it's approximately a 4 degree increase and there's very limited material that would be effected here. So from a power uprate perspective the materials construction really don't see much different.

CHAIRMAN DENNING: Well, we're certainly interested in this.

MR. WEAKLAND: Okay.

CHAIRMAN DENNING: But it does seem that a lot of it, except within the context of some temperature increase is why would have some additional concern about it.

MEMBER SIEBER: Well, I think just to amplify that a little bit, some folks suspect that there's sort of a need in the curve, right around 610. When you go beyond that the rate of degradation in some folks speculation may increase. And so you're right at that point. But I agree, the temperature increase is very small.

DR. BANERJEE: But isn't it very sensitive to temperature in this range, the susceptibility?

MR. KAMMERDINER: This is Greg Kammerdiner again.

I think the emphasis though is our degradation throughout the industry has primarily been at Ally 600 locations.

DR. BANERJEE: Right.

MR. KAMMERDINER: And what Denny's trying to point out here at Unit 1 we've eliminated that, for the most part, from the equation by replacing the generators with 690, by replacing the head penetrations with 690, we're planning to overlay the pressurizer nozzles, which are essentially Alloy 600 welds. There will be minimal amount of Alloy 600 left at Unit 1 and the bottom nozzles operate at cold leg temperature, so they should be on the lower susceptibility ranking of locations.

So as far as Unit 1 the 4 degree increase in temperature is somewhat mute at this point because we've basically taken the Alloy 600 out of the equation.

MEMBER MAYNARD: I believe it is sensitive in this range, but I think that for the temperatures you're going to they're still within what there's good history out there within industry. They're not becoming an outlier from breaking the ground.

DR. BANERJEE: Right. And Alloy 600 is out, this unit with the 4 degree rise. The other unit only has half a degree, right?

MR. WEAKLAND: Yes, sir.

MR. KAMMERDINER: Correct. Right.

MEMBER SIEBER: I think the interesting thing that sort of gives you some confidence is that one of the suspect heats was used in the Beaver Valley 1 reactor vessel head nozzles, the same one that didn't do well at Davis-Besse.

MR. WEAKLAND: Right.

MEMBER SIEBER: And they have seen a leakage or other problems there. But they have still replaced the head.

MR. WEAKLAND: Yes, that's correct.

MR. PATNAIK: I'm Pat Patnaik from DCI, Dividend of Component Integrity.

I want to add one more thing here. That the cold leg temperatures go down actually by a couple of degrees. As a result I don't see any problems with the bottom mounted nozzles.

MEMBER SIEBER: Right.

MR. WEAKLAND: Right. Thank you.

I will then just brush over what's at Unit 2 just to give you an idea of what plans are on Alloy 600.

We are planning mitigation in the areas for pressurizer nozzles for weld overlay. Management's currently looking at multiple approaches to address the cold leg loops, as we have Alloy 600 there. I think which will leave us with the BMNs, the internals, the generator tubing and the CRDM nozzles. And since the amount of temperature movement is very, very slight, we would expect no change from our current history, and we'll continue our inspections.

The other thing I want to touch on where the power uprate does have some effect because of the increase of fluence and the fluence impact is the area of materials for the two units. I'm going to talk a little bit more about the fluence, the uprate, the increases in improved capacity factor and what it has done with our projected EFP wise and end of expected life.

When we looked at the surveillance schedule, there will be no change in our schedule. We'll still pull five capsules for Unit 1, four for

Unit 2 in accordance with Appendix H. No changes there.

The upper shelf energy, both units at the end of -- actually at the end of extended life because I've done some of that with our projections there, are still good for upper shelf. So really the impact for the power uprate has been minimal for upper shelf.

Our PTS screening criteria for Beaver Valley Unit 1 and Unit 2, both our units are a little unusual in the industry in that they're both plate limited. Many vessels or most vessels are actually weld limited. Ours are plate. And I'll touch on the numbers we have those in the next slides.

We've looked at the applicability for the heat up and cool down curves. In the application what we did is we artificially took our existing heat up/cool curves for Unit 1, conservatively rolled back the effective dates so that until the LAR gets into position, that the effected curves have just been moved from 20.80 EFPY to 27.44 so that we know we don't exceed those limits. Base the fluence for heat up and cool down. As we do more testing and analysis then we'll adjust those in accordance with our PTLR and move forward.

Okay.

In the area of fluence in relationship to the uprate, we used a basis for WCAP Capsule & material at 3.54 E19 fluence. And our RTpts based on that fluence is 259. Capsule Y meant it was a major change in our fluence projections. We gained almost 12 degrees, which is very good. And that assumed a 1.4 uprate, but did not address the 8 percent uprate at the time that capsule was pulled. So when we made the uprate LAR and backed the effected EFPYs down, assuming that a power uprate would have done in June of '03 and holding the fluence constant at 3.54.

At Beaver Valley Unit 2 we used a Capsule Y data of 32 EFPY, fluence of 3.8 and RTpts of 149.

And incidentally, the RTpts screening number is 270 for plate for both units. It had included the 1.4 percent uprated and the 8 percent uprate. So the Unit 2 numbers were reflective of a June '03 power uprate, so they are conservative.

MEMBER SIEBER: Have you made any projections for renewed license end of life?

MR. WEAKLAND: Well, that's going to lead to the next slide, Jack. Thank you.

MEMBER SIEBER: Yes.

MR. WEAKLAND: As a result of looking at a potential extended license and the excellent operation of the past three cycles at Beaver Valley operating capacity factor in the high 90, 97, 98 percent; projecting those kind of capacity factors into the future and the 8 percent power uprate based on June of '06 what we're seeing now is an expected end of life EFPY of about 30.5 at the same fluence.

MEMBER WALLIS: Doesn't the fluence change with the uprate?

MR. WEAKLAND: Well, the fluence in this particular case didn't happen to change from the projection because the projection was made assuming that the uprate would have occurred in June of '03. And since the fluence is really controlled by core and when the uprate occurred, the 3 years delay provided me that cushion. And the core design being maintained at L4P has maintained the fluence at 30.5, virtually 3.54. The numbers like -- it's like 3.51 or 3.52 is very, very close to 3.54. At 30.5 at the end of our existing license life. That's reflective of the capacity factor and then this uprate in June this year.

At Unit 2, it's just coincidental I had a capsule due. It came to the NRC last week, so it's very new information to them, the submittal. And I did the projection of 36 EFPY for EOL. The reason I did that is when I did the projections looking into the future based on the higher capacity factors, it looks like we'll be at the end of our 40 years license somewhere around 35.1 to 35.2 actual EFPY. So 36 pounds allows me to be conservative.

As you can see, both of them give me RTpts that are still well below the screening criteria.

MEMBER WALLIS: Well RTpts doesn't seem to change at all as you do all this --

MR. WEAKLAND: No. It's based on fluence, that's why.

MEMBER WALLIS: But your fluence has changed for BV2.

MR. WEAKLAND: BV2 the fluence -- the difference between the two numbers, too, it comes into rounding of RTpts. At the earlier fluence of 32 FPY I think it was 3.86. The actual number when you run it and if you run out a decimal point or two, it's like 148.7.

MEMBER WALLIS: Well, it's so low it doesn't--

MR. WEAKLAND: It just doesn't matter. Right. And that's the reason for those activities.

MEMBER SIEBER: Well, what will it be after 60 years of licensed operation? Do you know that?

MR. WEAKLAND: On Beaver Valley Unit 1 we could reach 60 years of power operations and still be below the 270 criteria right now.

MEMBER SIEBER: You will?

MR. WEAKLAND: It's going to require some fuel management, some continued fuel management. We stay at L4P, we get within 2 years of extended license operation doing absolutely nothing different than we're doing today.

MEMBER SIEBER: I think you don't make it.

MR. WEAKLAND: We can make it.

MEMBER SIEBER: Oh, you can, okay.

MEMBER WALLIS: By then the PTS rule may have changed.

MR. WEAKLAND: Yes. Well, we believe it will be changed. Beaver Valley was the model plant for the NUREG and it's been very well studied by Oak Ridge. And if I look at their numbers, I'm probably good for a 100 EFPY, and I like their numbers.

MEMBER SIEBER: Too bad it's not regulation.

MR. WEAKLAND: Oh, yes. We're working on it.

In summary, the temperature assessment for the two units show really no programmatic impact on either the Alloy 600 or the steam generator program.

Fluence assessments, no significant impact on either the vessel integrity, upper shelf.

Maintaining our core, I don't see any problem. There's some small changes in response to materials. It will be managed under the rest of our programs. That primarily deals with internals activities, BMNs and the rest. And we have programs in place to monitor and maintain those through the rest of plant life.

MEMBER SIEBER: How many tubes are plugged percentage wise in Unit 2, steam generator 2?

MR. WEAKLAND: Unit 2? Greg?

MR. KAMMERDINER: This is Greg Kammerdiner.

Approximately 4½ percent.

MEMBER SIEBER: Pretty much even across the--

MR. KAMMERDINER: Pretty much. Yes, it's not like Unit 1 where we're skewed the one generator there. They're pretty evening distributed.

MEMBER SIEBER: What's the main reason?

MR. KAMMERDINER: Primarily sludge pile ODSCC.

MEMBER SIEBER: Thanks.

MR. WEAKLAND: Okay. That's all I have.

CHAIRMAN DENNING: Thank you very much.

MR. WEAKLAND: Any other questions?

CHAIRMAN DENNING: Hearing none, we will move on.

MR. WEAKLAND: Very good. Thank you.

CHAIRMAN DENNING: However, this is our final presentation of the day.

MR. MEDOFf: Good afternoon. My name is Jim Medoff. I'm a materials engineer for the --

DR. BANERJEE: Where are the slides for this?

MR. MEDOFf: They're in this package.

MEMBER WALLIS: Yes, the pages keep starting all over again.

MEMBER SIEBER: And you thought you were going to talk about materials.

DR. BANERJEE: Yes. It's after the control room thing.

MR. MEDOFf: Right.

MEMBER KRESS: Let me ask you a question, what did you do about the containment?

MEMBER WALLIS: What don't you start with page 7?

MEMBER SIEBER: Pretty good condition.

MEMBER WALLIS: A good slide to start with.

MR. MEDOFf: Good afternoon. I'm Jim Medoff. A materials engineer currently with the Flaw Evaluation and Welding Branch. My current supervisor is Dr. Kimberly Gruss. I just recently transferred over from the Reactor Vessels Internals Integrity Branch, which is currently being supervised by Mr. Matt Mitchell.

At the time of the EPU I was in the Reactor Vessels Internals Integrity program.

I'm here today to talk about our evaluation of the licensee's application with respect to the structural integrity of the reactor vessel and the reactor vessel internals components, and as well as the licensee's evaluations of its reactor coolant pressure boundary materials. And with respect to that, we're going to focus on the Alloy 600 and what they did to address it.

Next slide, please.

For the EPU we assessed the Staff's evaluation of how the EPU impacted the structural integrity of the Alloy 600 components, in particular whether it would change the crack growth rates if you postulated a crack occurring in the Alloy 600 components. And these included Alloy 600 base metal components as well as Alloy 682 or 182 filler metal materials.

For the most part, the piping at Beaver Valley Unit 1 doesn't include Alloy 600 materials, so we don't see a big impact on that. And Mr. Weakland provided a good summary for where the few components are located and addressed how they addressed structural integrity there.

For the Alloy 600 and the Alloy 82/182 welds in the Beaver Valley Unit 1 reactor vessel closure head, we determined that the licensee did replace the head in the last outage and we feel that the monitoring program that they're going to do this under the schedule for replacement head should address this. It includes not only Alloy 600 and 82/182 materials, but the ordered that we issued to the industry on Inconel materials also covers Alloy 52, 152 and Alloy 690 materials. So just the fact that they replaced the new materials doesn't change the requirements in the order and they're still required to follow that.

Next slide, please.

For Unit 2 the Alloy 600 and Alloy 82/182 materials in the Unit 2 reactor coolant pressure boundary are managed by the licensee's Alloy 600 management program. And what this program does is it does a susceptibility ranking of the components based on -- the susceptibility program is basically Uranus program that is a function of the temperature of the components.

DR. BANERJEE: There's no effect of stress on the -- I thought there was, as well -- I mean temperature is one effect, but stress must be another.

MR. MEDOFf: Stress probably comes in it, but I think the big factor in the Uranus program is the temperatures.

MR. PATNAIK: This is Pat Patnaik from Dividend Component Integrity.

The analysis has been done at 617 degrees which bounds the temperatures for power uprate.

DR. BANERJEE: Right. But --

MR. PATNAIK: That was done, has been done at a bounding temperature of 617 degrees. And with power uprate your hot leg temperature is not going over 611.3 degrees.

DR. BANERJEE: I'm just saying about the susceptibility ranking.

MR. PATNAIK: Susceptibility ranking?

DR. BANERJEE: Yes.

MR. PATNAIK: Well, the components that are Alloy 600 and welded with 82/182 filler metal have been ranked based on stresses and also the time and temperature.

DR. BANERJEE: Right.

MR. PATNAIK: Yes, that ranking has been done. And their volumetric inspections will be performed according to the susceptibility ranking--

DR. BANERJEE: Which take both factors into account.

MR. PATNAIK: Oh, yes.

DR. BANERJEE: Yes.

MR. PATNAIK: Of course.

DR. BANERJEE: All right. I'm happy with that.

MR. PATNAIK: Go ahead.

MR. MEDOFf: Okay. and in accordance with this program what they're going to do is they select the susceptible components for augmented inspection and they put the inspection in accordance with the program. So they do monitor for their Alloy 600 and Alloy 82/182 materials in Beaver Valley Unit 2 plant.

With respect to the Alloy 600 nozzles and Alloy 81/182 partial penetration welds in the Unit 2 head, they are categorized as highly susceptible heads to primary water stress corrosion cracking and FirstEnergy does perform augmented inspections of these things in accordance with the criterion in the first order for high susceptible reactor vessel closure heads. And this complies with the rule and should address structural integrity for those components.

Next slide, please.

From my review I reviewed the impact of the EPU on the reactor vessel and the reactor vessel internals, the internals components.

With respect to the reactor vessel, we really focused on how the EPU would impact the fracture toughness assessments that we require for the ferritic materials in the reactor vessel. This includes the RTpts calculations to ensure integrity against the events of a pressurized thermal shock event. The RTpts calculations that go into the pressure temperature limit calculations, the upper shelf energy calculations for demonstrating margins against -- tearing of the reactor vessels materials and each of those assessments requires that they account for the effects of irradiation and they monitor for that through their reactor vessel surveillance program. So we assess the impact of EPO on the withdraw schedule for that program.

We also looked at the impact on the structural integrity of the RV components. And I'll address that later on in the presentation.

Next slide, please.

With the impact on the RV surveillance capsule program, the program's required by 10 CFR Part 50 Appendix H. And basically the rule requires them to withdraw surveillance capsules in accordance with ASTM Stand EI185-82. In accordance with that standard the licensee is required to pull 5 capsules from Beaver Valley Unit 1 and 4 capsules from Beaver Valley Unit 2. And it's really dependent on what the limiting shift in the reference temperature will be for that vessel at the end of life.

We found out that there were a few minor adjustments to the withdrawal schedules for the remaining capsules because each one has one remaining capsule to get pulled. And I'm not sure whether that report that Mr. Weakland referred to in his presentation was actually one of those capsules. But from the data I had, they were still required to pull two capsules for the plants.

Basically, we find that the changes that they propose to the schedules were still in accordance with the ASTM standard and so we found that the EPU didn't impact the overall schedules for the units. We found them to be acceptable.

Next slide, please.

For the PTS assessment, the calculation of RTpts values is required by 10 CFR 50.61. As Mr. Weakland said, the rule establishes screening criteria of 270 degrees for reactor vessel base metals and axial weld materials. And a screening criteria of 300 degree for reactor vessel circumferential weld materials. And these are upper limits on the adjusted reference temperature for RTpts value.

The licensee gave you his values. We did independent calculations of the RTpts values using our reactor vessel integrity which mods the methodology in the rule for doing these calculations. And we came up with an RTpts value 259.5 based on the fluence provided by the licensee for Unit 1. And RTpts value of 148.6 degrees F for Unit 2 based on their end of life fluences. And therefore, we didn't see any impact of the appeal in compliance with 10 CFR 50.61.

Next slide.

Basically we looked at the impact on the pressure temperature limits, but to make it sweet and short, Generic Letter 9603 allows them remove their pressure temperature when it's from the limiting conditions of operations in the technical specifications if they put them into a owner controlled documents called the Pressure Temperature Limits Reports. And they calculate them within an NRC approved methodology, any changes to those technical specifications PTLR figures are done through an administrative tech spec.

We granted license amendments for them to do this in 2002 and 2003. And although there may be changes in the RTndt calculations that goes into these PT limit calculations, they'll be done through the PTLR process, and that's acceptable to us.

Next slide, please.

Like the RTpts calculations, we looked at the impact on the effort of shelf energy assessment for the plant. Basically we used this parameter as a measure of looking at the remaining ability to withstand ductile taring in the reactor vessel materials. It's governed by 10 CFR Part 50, Appendix G.

The rule establishes that the upper shelf energy values must be greater than 75 foot pounds in the unirradiated condition and greater than 50 foot pounds through the licensed life of the plant including all of accounting for the effects of irradiation.

We did our independent calculations of the upper shelf energy values for limiting materials and we agree that the limiting materials for Beaver Valley are all plant limited, both for RTpts and for upper shelf energy. We calculated for Unit 1 an upper shelf energy value at end of life under EPU conditions of 53.8 foot pounds and for Unit 2 a 59.4 foot pounds. Both of these comply with the acceptance criteria 50 foot pounds at end of life. So we didn't see an impact on the ability to comply with 10 CFR Part 50 Appendix G.

Next slide.

The last thing we assessed is the impact on the structural integrity for the reactor vessel internals. All of our assessments were done in accordance Matrix-1 of Review Standard RS-001. And with respect to this we really look at whether the fluence for these materials above a certain level, a certain threshold because above that threshold there is a concern that the materials, the components maybe susceptible to irradiation assisted stress corrosion cracking. And what the matrix specifies you should do if you're above the fluence is either provide a commitment and provide an augmented inspection program for these components or commit to participation in industry initiatives that are being performed on age related degradation of these components. And we sent out an RAI informing the licensee of this document, and they did provide the proper commitment to the NRP initiatives. And this satisfied the matrix. And so we concluded they were sufficient for the RV internals.

So basically we assessed six things: The Alloy 600 materials, the structural integrity of the RV internals, the PTS assessment and the upper shelf energy assessment and the RV surveillance program. And we concluded that an impact to safety margins or that they were providing commitments to provide augment inspection programs.

CHAIRMAN DENNING: Questions?

MEMBER WALLIS: Thank you.

MR. MEDOFf: Thank you.

CHAIRMAN DENNING: According to the agenda, it is now 5:00 p.m., so we will recess.

(Whereupon, at 6:09 p.m. the hearing was adjourned until 8:33 tomorrow morning.)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee Reactor Safeguards Subcommittee on Power Uprates
Docket Number:	(not applicable)
Location:	Rockville, Maryland
Date:	Tuesday, April 25, 2006
Work Order No.:	NRC-982

Pages 1-396

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

+ + + + +

BEAVER VALLEY POWER STATION EXTENDED POWER UPRATE

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TUESDAY, APRIL 25, 2006

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The subcommittee meeting convened at the Nuclear Regulatory Commission, Two White Flint North, Room T-2B3, 11545 Rockville Pike, at 8:30 a.m., Richard B. Denning, Chair, presiding,

<u>SUBCOMMITTEE MEMBERS PRESENT:</u>

RICHARD B. DENNING, Chair
SANJOY BANERJEE
ACRS Consultant
THOMAS S. KRESS
OTTO L. MAYNARD
JOHN D. SIEBER
GRAHAM B. WALLIS

<u>ACRS STAFF PRESENT:</u>

RALPH CARUSO

FIRSTENERGY STAFF PRESENT:

A.R. BURGER

FENOC

MATT CERRONE

Westinghouse

DON DURKOSH

FENOC

KEN FREDERICK

FENOC

DAVID FINK

Westinghouse

CHUN FU

Westinghouse

NORM HANLEY

Stone & Webster

JOSH HARTZ

Westinghouse

GREG KAMMERDINER FENOC

BRETT KELLERMAN

Westinghouse

JAMES LASH

FENOC

MARK MANOLERAS

FENOC

CHRIS MCHUGH

Westinghouse

BRIAN MURTAGH

FENOC

MAHESH PATEL

FENOC

JACK PENKROT

Westinghouse

PETE SENA

FENOC

GEORGE STORLIS

FENOC

MIKE TESTA

FENOC

DENNIS WEAKLAND

FENOC

NRR STAFF PRESENT:

TIMOTHY COLBURN

RICHARD LOBEL

JIM MEDOF

SAMUEL MIRANDA

JOHN PARILLO

PAT PATNAIK

LYNN WARD

A-G-E-N-D-A

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

8:32 a.m

CHAIRMAN DENNING: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates. I'm Richard Denning, Chairman of the Subcommittee.

Subcommittee members in attendance are Tom Kress, Otto Maynard, Jack Sieber, Graham Wallis who is virtually at the moment, but will be physically here later and our consultant Sanjoy Banerjee, who also seems to be virtually here.

The purpose of this meeting is to discuss the extended power uprate application for the Beaver Valley Power Station. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC Staff and the Beaver Valley Power Station licensee, FirstEnergy, 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 April 12, 2006.

A transcript of the meeting is being kept and 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 received any requests from members of the public to make oral statements or written comments.

We think that the agenda that we're going through today and tomorrow is quite well balanced towards addressing the principal interests and interests of the Subcommittee. We know that the power uprates will result in some eating into safety margins. WE need to know where that's occurring and become convinced that the margins are still adequate.

This is a very quantitative Committee. The Staff's review of the application must be comprehensive, our view must in many sense be in many aspects be more focused. We'd like you to spend minimal time on the aspects of plant safety that are not effected by the uprate. The nice thing about having the safety analysis results today is that there is always tomorrow to ask you to come back and give us more detail.

You'll notice our room has been modified somewhat over the last couple of weeks. I hope that everything's going to work okay. I know the screen isn't perfect, but we will proceed.

Now I would like to turn the meeting over to Mr. Colburn of the NRC Staff to begin.

MR. COLBURN: Thank you, Mr. Denning.

My name is Tim Colburn. I am a Senior Project Manager in the Division of Operating Reactor Licensing in the Office of Nuclear Reactor Regulation. I'm assigned to the Beaver Valley Power Station, Units 1 and 2.

During the next two days presentations will be made by the Staff and the licensee concerning background information related to the application, plant changes associated with the application and fuel and core design changes, safety analysis including methodology used for conducting those safety analysis, discussion of non-LOCA events and large break LOCA.

The Staff and licensee will conduct discussions of the safety analysis.

The safety analysis discussion will also include discussions by licensee and the Staff on small break LOCA, long term cooling and boron precipitation, containment over pressure credit and dose analyses.

The Staff will also provide a discussion of the containment analysis associated with the conversion from sub-atmospheric to atmospheric conditions and its dose analysis and implementation of the alternative source term.

CHAIRMAN DENNING: I think you can just arrow down, Tim, if you want to there.

MR. COLBURN: The Staff and the licensee will also discuss the materials and reactor vessel integrity issue associated with the safety evaluation for the power uprate.

On day two a discussion of the balance of plant issues associated with the power uprate, flow accelerate corrosion, vibration, corrosion erosion and risk evaluation will be conducted by both the Staff and the licensee.

Operations and testing associated with the power uprate including human factor issues, power ascension testing and the licensee test plan for basically what amounts to a two phrase implementation of the testing will be discussed. And then conclusions of the licensee and the Staff.

The licensee had several license amendment applications that they had submitted prior to the power uprate which were needed to support the power uprate review. These included:

Steam generator allowable value setpoint changes, which were to eliminate concerns the Staff had with measurement uncertainty;

A containment conversion license amendment application to convert the Beaver Valley Power Station 1 and 2 containments from sub-atmospheric to atmospheric conditions;

Best estimate LOCA methodology approval for the large break LOCA analyses;

Steam generator replacement for Beaver Valley Power Station Unit 1 only. Replace the previous steam generators with the Model 54F steam generators; and

Implementation of the relaxed axial offset control methodology for both units.

These amendments have all been approved and all have been implemented for Unit 1. Implementation of some of these will be for Unit 2 in the fall of 2006 outage.

The licensee's submittal originally was sent in on October 4, 2004. It had numerous supplements. The licensee had submittals on February 23rd and June 14 of 2005 which were necessary to consider the application a complete application. The Staff issued its acceptance review of the licensee's application in July of 2005 and indicated that it would be reviewing the application for basically within a one year time frame.

The licensee's application requested an increase in reactor power from the current 2689 megawatts thermal to 2900 megawatts thermal. This is approximately an 8 percent increase in power and is considered an extended power uprate.

The Staff plans to issue its safety evaluation and amendment on or about the end of June 2006. The licensee plans to implement the extended power uprate for Unit 1 within 120 days of receipt of the approval. And for Unit 2 in a phased approach concluding with the completion of balance of plant upgrades including a turbine upgrade in the spring of 2008.

What I'd like to do now is turn the presentation over to the licensee's site Vice President Mr. Jim Lash for his opening remarks.

MR. LASH: First off, my name is Jim Lash.

CHAIRMAN DENNING: No. Hold on just a

second.

MR. LASH: Okay. First off, my name is Jim Lash, site Vice President of Beaver Valley Power Station.

Good morning, Mr. Chairman and distinguished members, ACRS consultants. This morning I'd like to provide a brief introduction and some background to the Beaver Valley power uprate. Our decided outcome is to provide you with sufficient information and answer all relevant questions regarding the Beaver Valley power uprate so that you can form appropriate decisions and recommendations to the NRC Commissioners.

We've built this presentation to cover a number of areas effected by the uprate in areas that we believe are of interest to the Committee in fulfilling the desired outcome of these proceedings.

We have a full agenda of items to cover in the next two days, and that is shown here on this slide.

I'd like to introduce the presenters from FENOC. Other than myself will be Pete Sena will provide an overview. He is the Director of Engineering at Beaver Valley.

Mark Manoleras on plant changes. He is

the Design Engineering Manager at Beaver Valley.

A.R. Burger will do reactor fuel and core design. He is a supervisor of core design.

Ken Frederick will address safety analysis. He is a nuclear safety analyst.

Dennis Weakland materials and reactor vessel integrity. He's a fleet material representative.

Mike Testa the mechanical plant VOP. He's the EPU Project Manager.

Risk evaluation Colin Keller, who is the supervisor of the PRA group at Beaver Valley.

And finally the operations and testing aspects of this project will be Don Durkosh, who is a senior reactor operator.

Each presenter will describe their area of expertise and introduce any subject matter experts that they'll use during the course of their presentation and at the time of their presentation.

In addition to the presenters we have subject matter experts here from Beaver Valley as well as some contractors, organizations supporting us, Westinghouse and Stone & Webster.

The balance of my comments will briefly focus on the history of Beaver Valley, the extended power uprate time line, the peer units experienced with power uprate and the oversight of our power uprate project.

Okay. Beaver Valley units are three loop Westinghouse PWRs that achieved commercial operations in 1976 for 1776 Unit 1 and 1987 for Unit 2. The original core licensed power was 2652 megawatts thermal or 2660 megawatts thermal NSSS power. And both units have currently implemented a 1.4 percent uprate to 2689 megawatt thermal or 2697 megawatt thermal NSSS power. This uprate credited the improved feedwater flow measurements implemented in the fall of 2001.

CHAIRMAN DENNING: Let me ask you just a couple of questions related to the differences between the two designs. Obviously there's a long distant time differential between when the two were started. But even before we get into the steam generator replacement there are some fairly significant differences. And you have, I gather, separate simulators for the two. Can you give me just a little feeling as to what the principal differences are just at this point prior to?

MR. LASH: Well, they're principally the same design, however there is a time difference between the implementations of those units so there is a difference in some aspects of the systems for both units.

CHAIRMAN DENNING: Yes.

MR. LASH: We do qualify operators independently for those two units, so we have dual simulators to maintain a bank of SROs qualified personnel for each unit. We're not dual licensed on the plant.

The specific design aspects I think we'll get into in the safety analysis and how we've treated those differences later on with some of the other presenters.

CHAIRMAN DENNING: Yes. But the operators are licensed to operate just one or the other unit?

MR. LASH: That is correct?

CHAIRMAN DENNING: And do some of them learn how to do both or --

MR. LASH: We have had personnel licensed on both units. For example, Pete Sena who will follow me was licensed on both Unit 1 and Unit 2.

CHAIRMAN DENNING: But any particular time they're dedicated towards one or the other?

MR. LASH: Predominately the SROs are qualified and maintain a license, an active license, only on a single unit.

CHAIRMAN DENNING: Thanks.

MR. LASH: A time line of Beaver Valley. This is a recent time line starting in 1998. The first item I'd point out there is that FirstEnergy Nuclear Operating Company was formed in December of 1998. And that operating company has now matured to a fleet organization and is staffed to support all functional areas at the three nuclear stations Beaver Valley, Davis-Besse and Perry.

FENOC Corporate is currently charged with providing governance and oversight of all station activities.

Beaver Valley was purchased by FirstEnergy from Duquesne Light & Power Company in late 1999 through an asset swap of fossil fire units for the nuclear station.

In early 2000 FENOC implemented a full potential program for Unit 1 and Unit 2 with a key objective of managing design margins and increasing the electrical output of both units. The EPU project, which is a subset of this potential program, has updated the station's analyses to include the selected final design of the Unit 1 steam generators, which were already referenced as the Model 54, which were recently installed during the last outage at Unit 1. We'll talk about that briefly in a moment.

In total, the EPU project and its supporting projects, steam generator replacement, containment conversion, best estimate LOCA and others that will be referred to this morning span a period of 6 years. As a result of the project, Unit 1 and Unit 2 have established a revised baseline of supporting plant analyses that will be used to manage design margins for the remaining life of both units. This is in keeping with the original premises of the parent full potential program that I spoke of earlier.

I previously mentioned the recently completed outage at Unit 1. Let me briefly touch on the scope and significant accomplishments of that outage.

This is a picture of our containment. You can see that we replaced all three steam generators in this outage. By the way, this outage completed April 19, last Wednesday at 2018. And Unit 1 has achieved 100 percent power, full power operation on Sunday at 1400 hours and it remains at 100 percent power.

So during the outage we replaced the steam generators and the reactor vessel head with a modified simplified design, and the major accomplishments in these replacements is obviously the elimination of the Alloy 600 aspect of materials that were associated with the older components.

Now shown here, because it's not in containment, is the main unit generator rotor was replaced. It has a short. We replaced it. And the main unit generator itself was rewound.

Now there were many other activities, but I won't go through all of those.

I would point out that the average time frame to do a steam generator outage first time for a station is about 82 days. Beaver Valley accomplished this outage in 65 days. And I believe that to be a very positive indication of both the strength of the organization as well as the level of planning and the preparedness for that outage.

The larger power uprate which we're referred to and why we're here today, 8 percent was initiated in mid-2000 and used an initial scoping phase to determine the best approach and the optimum targeted licensed power level. As a result of the scoping evaluation, a target power level of 2900 megawatts thermal or 2910 megawatts thermal NSSS was selected.

As you can see, that target aligns us very well with our peer three loop Westinghouse units that have already previous uprated. We benchmarked closely these units, both their approach to uprate and their operating history since its implementation. We feel that collectively using the experience of these stations gives us confidence in the approach we have chosen. Specific examples of benchmarking in implementation would be the use, for example, of the specification for Model 54 steam generators used at Farley Station and now at Beaver Valley. And the phased approach to implementing the uprate, which we will be discussing in greater detail later on in the presentation.

MR. CARUSO: Have you ever considered doing the stretch uprate?

MR. LASH: No, we have.

MR. CARUSO: I mean, I don't know if you've ever --

MR. LASH: We've never discussed it.

MR. CARUSO: Never discussed that?

MR. LASH: Next slide, please.

In the area of oversight, executive and senior management oversight of the project has been in place since its inception. The site leadership team has been closely involved, and this team includes the site Vice President, myself, the Plant Manager and Engineering Director.

A FENOC executive leadership team has also provided oversight and this includes our Senior Vice President of Engineering currently Dan Pace who bring unique experience in operating activities rom his previous role at Entergy.

Oversight of the engineering and licensing process that supports this uprate has been directly performed through implementation of the mentioned boards, committees and assessments. And an example of the independent assessment you find at the bottom there would be the NPR Associates for a review of our uprate supplemental.

That completes my introductory comments. And if there are no other questions, I will turn over the presentation to Pete Sena, the Director of Engineer for Beaver Valley. Thank you.

MR. SENA: Good morning. Again, I'm Pete Sena. I am the Director of Engineering at Beaver Valley. My previous position at Beaver Valley was as the Operations Manager and also as a senior reactor operator at both units. So I did hold a senior reactor operator license, active license for both units simultaneous. So I'd take a stand working both units one at a time, so I do have a unique perspective as far as the differences between the two units. And when we come into questions with respect to some of those specifics during the presentation, I can speak to it. And also we have one of our shift managers here, George Storlis, who is also licensed in both units, however at a different times. So we will be able to provide the Chairman with additional detail as you request.

I will speak to principally the preparations for the uprate, the general criteria, the project team and the technical reviews. And before I do so, I do want to comment that we at Beaver Valley did attend the previous Subcommittee meeting that Ginna participated in. We found that to be extremely helpful as we prepared for our presentation, and we have tailored our presentation we believe to what the Committee desires. We will focus heavily on our safety analysis so you can understand the margins that remain following the uprate. We will be going into great detail on our LOCA and our limiting non-LOCA transients, such as a loss of feedwater and uncontrolled rod withdrawal accident. So as we go into those details, I think you'll appreciate what margins do remain.

All right. As you can see from this next slide there were several amendments that have prepared Beaver Valley for the power uprate. And again, the uprate project was a full potential project initiated back in the year 2000. Just that some of these amendments will be touched on as we go through the presentation, but I would like to speak to several of them right here.

The positive moderator temperature coefficient was previously approved and implemented back in the year 2002. So what that has enabled us to do is to gain operating experience on startup with a slightly positive MTC throughout the years now that we've had several cycles of operation. I personally was the first SRO to perform a reactor startup with that slightly positive MTC.

Now that experience and the lessons learned have been captured and formalized for subsequent crews and subsequent startups.

Also the alternate source term, we will speak about that again in the future, but we did selectively apply AST to several accidents such as a fuel handling accident LOCA, rod ejection. And what this permitted Beaver Valley to do was to eliminate or retire circle systems, and one in particular would be what's called the control room air model pressurization system which, Mr. Sieber, you may remember that that has challenged the plant in the past with an inadvertent actuation which had resulted in a dual unit shutdown, a tech spec 303 shutdown. So there were several benefits towards that selected implementation.

Finally, containment conversion and best estimate LOCA, those amendments were previously approved by the NRC in the first quarter of this year. On the containment conversion, there is an industrial safety benefit that the site has realized with respect to more frequent and safer containment entries at power to allow for inspection of various components as we see fit.

CHAIRMAN DENNING: What did you lose on that in terms of -- you know, it's never been absolutely clear to me why they were sub-atmospheric and what the perceived benefits were of that and how this might impact it.

MR. SENA: What I'd like to do is defer that because we have an entire presentation on the containment conversion and we're going to go through that in great detail.

CHAIRMAN DENNING: Okay.

MR. SENA: A couple of things, though. We did not change the containment design pressure of 45 pounds. We did not change the structural design temperature of 280 pounds. But there are several aspects that were a benefit to the plant. For example, the increased initial pressure provides additional back pressure for the loss of coolant accident. However, but we still need to meet our designed pressure of 45 pounds. So we will go into the detail on that particular amendment.

MEMBER SIEBER: Maybe before you soot away from that, the idea early on was to be able to build a smaller containment, spend less money on concrete and rebar. And if you started out at a sub-atmospheric pressure, the presumption was that you would not reach as high in ultimate pressure. On the other hand, the containment was built as a large dry strong containment and the sub-atmospheric really didn't change things all that much.

One of the advantageous, though, is you get increased head to the sump because you're starting at higher pressure, which could assist in the recirculation phase of a LOCA accident.

I have a question about the positive moderator temperature coefficient. It's quite common to have a positive moderator temperature coefficient when the plant is cold. I presume that you're still positive when the plant is hot early in core life?

MR. SENA: It's --

MEMBER SIEBER: And that goes away sometime probably a third of the way through core life?

MR. SENA: At about 30 percent power. We're really starting off with zero feedback, around a zero moderator temperature coefficient upon initial criticality and the initial power ascension. Once you come up to around 30 percent power and increase power, it then starts --

MEMBER SIEBER: It goes the other way?

MR. SENA: -- inching it in the positive direction.

MEMBER SIEBER: Oh, okay. And does that stay throughout the life of the cycle?

MR. SENA: Well, again throughout the cycle the same. As --

MEMBER SIEBER: At burndown it changes?

MR. SENA: -- you bring up the boron -- right. Then you're progressing towards a more traditional negative MTC.

MEMBER SIEBER: Right.

MR. SENA: To maybe minus 4 or minus 5.

DR. BANERJEE: The increased pressure, does that lead to increased temperature in the sump water?

MR. SENA: I'll tell you what we're going to do is we're going to go through specifically the need for containment overpressure during our presentation.

DR. BANERJEE: Right.

MR. SENA: We currently at Unit 1 do credit containment overpressure and will continue to credit overpressure. And the onset of the accident, Mike, what's our initial steam temperature about 280 degrees?

MR. TESTA: This is Mike Testa, the Project Manager at Beaver Valley.

Pardon, could you repeat?

MR. SENA: The initial temperature for the assumptions for containment overpressure, for containment sump temperature?

MR. FREDERICK: You want to answer. I'm here. This is Ken Frederick.

When the initial pumps start, the sump temperature is around 260 degrees.

DR. BANERJEE: And what would have been in the sub-atmospheric case?

MR. FREDERICK: It's roughly the same. I'll show you some slides later that show you how that changes.

DR. BANERJEE: So you say it doesn't change?

MR. FREDERICK: It goes up a few degrees, not much. The initial pressure change does not really impact the transient conditions and some of that's due to some methodology changes that we've incorporated in its analysis.

DR. BANERJEE: Okay. You'll speak of this in detail, right?

MR. FREDERICK: Yes.

MR. SENA: Yes. We have a specific presentation talking specifically towards containment over pressure.

Finally on the best estimate LOCA again, that was recently approved. Both containment and conversion and best estimate LOCA were both approved first quarter of this year and have been implemented at Unit 1 upon the completion of the Unit 1 outage.

At Unit 2 we have a full outage, those two amendments will be implemented on the completion of the Unit 2 outage.

CHAIRMAN DENNING: Was that essentially to be able to accommodate the uprate?

MR. SENA: Yes, it was.

All right. The best estimate LOCA that we're speaking of is not the ASTRUM methodology utilized by Ginna, but the more traditional COBRA/TRAC. And we will discussing best estimate LOCA in a future presentation. But it is the same methodology used by Gravewood, Byron.

Next slide, please.

Again, is the key elements of the uprate. I think I've spoken to these already with respect to the containment conversion and best estimate LOCA. And, again, we will go into great detail on analyses.

Next slide.

And the message about this slide is simply that we at Beaver Valley did not forge new ground here. We followed the same methodology used by other utilities in their uprate. There are no new or unlicensed industry methodologies being applied here.

Next slide.

As Mr. Lash said, this was a Beaver Valley led project. The ownership remained with us at the site. We did have corporate oversight, corporate oversight and governance. But, again, the ownership remained with our experienced site personnel.

We provided overall project management and direction. But, again, we had significant support from our teammates, from Westinghouse and Stone & Webster. And, again, many are here today in support and are various subject matter experts that we may call upon throughout the presentation.

Next slide.

Again, we at Beaver Valley, even though we did have vendor support, we reviewed and approved the design inputs and performed detailed owner acceptance of each vendor calculation.

Finally, I do want to make a comment in recognition of the NRC Staff. The NRC review and challenges and various RAIs were very detailed, very challenging and did result in a better project here today. And in particular, the Staff audits that were performed either at Westinghouse or at Beaver Valley in the area of PSA, safety analysis and radiological assessment did significantly help us to come to closure on many open items and also significantly streamlined the review process. So we do appreciate that from the NRC.

Next I'd like to introduce Mark Manoleras. Mark is the Manager of Design Engineering at Beaver Valley. Mark will be looking at the plant modifications that we had done and plan to do at Beaver Valley.

Thank you.

MR. MANOLERAS: Thank you, Pete.

My name is Mark Manoleras. I'm the Design Engineering Manager at Beaver Valley. I've been the Design Engineering Manager since 2002. My department's responsibility has been the oversight and performance of the modification packages and the safety analysis associated with the uprate.

At this time I'd also like to mention in the back, Mahesh Patel. Mahesh Patel is my lead electrical engineer. He will be here to support the second part of my presentation.

Next slide, please.

I'd like to discuss three areas today. I'd like to discuss the plant modifications that were performed to support the safety analysis for the power uprate. Many of these modification packages were performed to satisfy initial conditions in the safety analysis. I will touch on the modification package, discuss it briefly and we will discuss each modification in great detail when we come up to the safety analysis section.

I'd also like to spend a few minutes to

talk about the electrical system summary. The electrical system summary we will spend some time on it. There was very minor changes associated with the electrical system associated with the power uprate. So we will touch on it in my portion of the presentation.

And we will also discuss the use of operating experience. The operating experience that we touched on during the project.

Next slide, please.

As you see, this is the start of a list of our plant modifications that were performed for the power uprate. I will discuss each modification and then I will identify its status whether it had been implemented at Unit 1 or Unit 2.

The first modification is replacement of our charging/safety injection pump rotating assemblies. This modification extends our pump runout flow limit and it improves high head margin and it improves small break LOCA margin.

At Unit 1 we have replaced all three of our charging pumps. At Unit 2 we have currently replaced two of those three pumps, and currently are planning to replace our third pump prior to our Unit 2 outage, which will implement some of the amendments that you saw previously.

The next modification package I would like to discuss is the addition of fast acting feedwater isolation valves at Unit 1. These valves reduce containment pressure following a mainstream line break inside containment. And they also provide redundant isolation capability for feedwater isolation events. These feedwater isolation valves are already existing at Unit 2.

I'd also like to discuss briefly the addition of aux feed cavitating venturies at Unit 1. These venturies minimize mass input to containment and reduce aux feed flow on a feedline break and maintain minimum flow to the intact steam generator. These cavitating venturies already exist at Unit 2.

We also added a reactor cavity drainage port at Unit 1 to facilitate post-accident drain to improve NPSH performances as pump draw from the sump. We intend to install that reactor cavity drainage port at Unit 2 in our next outage.

We eliminated our quench spray cutback feature and it's not longer required due to the containment analysis at Unit 1. This quench spray cutback does not exist at Unit 2.

Additionally, we replaced our steam

generators at Unit 1 and that includes the narrow range level transmitters. We increased the narrow range span. And we'll talk about that in great detail in the non-LOCA analyses that follow.

DR. BANERJEE: Why was it necessary to put those auxiliary cavitating venturies?

MR. MANOLERAS: Yes. What we did that for was we wanted to make sure that we minimized the mass input to containment following that feedline break. We wanted to do that. Basically reduce the mass addition to the containment following a feedline break.

DR. BANERJEE: And that came about because of the uprate?

MR. MANOLERAS: That's correct. Basically part of the containment analyses.

MR. TESTA: Yes. This is Mike Testa again from Beaver Valley.

As Mark said, Unit 2 plant already had that feature, had cavitating venturies installed in the auxiliary feedwater system.

When we looked at Unit 1 we wanted to again, as Mark said, help support the revised mass and energy release to the containment for feedline break and a steamline break. And it also helps to protect the pumps from run off condition. So early on in the project we decided to install those cavitating venturies and then credit those in the mass and energy release for the containment analysis.

DR. BANERJEE: I guess a more general comment is I see a list of things you're doing, but I don't have a clear picture of why you do them. And does this come out later on or --

MR. MANOLERAS: Yes. Actually, when we get to the safety analysis section of the presentation we will identify which modification packages satisfy which initial conditions of those analyses.

DR. BANERJEE: Anyway, if you could just briefly mention the why, that would be very helpful.

MR. MANOLERAS: Okay. I will do that.

DR. BANERJEE: Why do you replace the steam generator? Maybe it's obvious, but we'd like to know.

MR. MANOLERAS: Yes. For example, our Unit 1 steam generators were the oldest steam generators in the country. We basically had very limited tube plugging margin there. So we installed new steam generators. The generators that we installed actually do not have any tubes plugged. So, obviously, that was the reason that we did that Unit 1. That's an example.

DR. BANERJEE: Okay.

MR. MANOLERAS: Okay. Next slide, please.

We replaced our high pressure turbine at Unit 1 with a turbine with all reaction design. At Unit 2 we're going to do that also. We basically needed to do that to basically maximize our megawatt capacity; that's why we did that.

At Unit 1 we already installed stakes in our main condenser to eliminate any vibration issues. We intend to install those stakes in the Unit 2 condenser so we do not have any flow induced vibration issues there.

MEMBER SIEBER: What's the tube material at Unit 2 condenser.

MR. TESTA: It's stainless.

MEMBER SIEBER: Stainless. Yes. Is the original.

MR. TESTA: Yes.

DR. BANERJEE: And the steam generator tubes?

MR. TESTA: Steam generator tubes?

MEMBER SIEBER: 690 for Unit 1, 600 for Unit 2

MR. MANOLERAS: 600. And we go into great detail. We have a materials presentation. We'll go into great detail on that.

At Unit 1 we did not have to replace our cooling tower fill. We had adequate cooling tower fill. We did not have to replace that.

At Unit 2 we put in a high efficiency fill.

MEMBER SIEBER: You may want to tell what cooling tower fill is.

MR. MANOLERAS: Basically this is the material in the cooling tower that helps I guess the heat exchange capacity or capability of that cooling tower. So the fill material will allow the dissipation of heat in the cooling tower, I guess is the best way to describe it.

DR. BANERJEE: Why does it do that?

MR. TESTA: Again, this is Mike Testa.

For the cooling tower on the circ water side of the cooling tower, basically you pump the water into the tower and the water will rain down, basically, in effect over this fill. And the fill it helps to aerate, in effect break up the water and help aerate it. That way when you bring the natural draft of the tower through it, it'll help remove heat.

MEMBER SIEBER: In Unit 1 it looks like venetian blinds.

DR. BANERJEE: Huh?

MEMBER SIEBER: In Unit 1 it looks like venetian blinds and the water cascades down through it and the air is going through at right angles.

I take it that all the asbestos that was in there is now gone?

MR. MANOLERAS: That's correct.

DR. BANERJEE: Then the last point raise set pressure, is that just for the cycle or what?

MR. MANOLERAS: No. We intend to make a permanent change. We've actually made that change. We raised that setpoint to the MSR reheater relief valves. We did some analyses, BOP analyses that identified that we would have limited margin error. So we went out and we retested and reset our MSR relief valve setpoints.

DR. BANERJEE: Margin to what?

MR. TESTA: This is Mike Testa again.

As Mark said, we redid the heat balance for the power uprate and we looked at the operating pressure at the MSR. The operating pressure in effect went up about 10 pounds. Okay. We had relief valves that were set originally at 250 psig. And then because of the uprate and they increased in operating pressure of about 10 pounds, we modified the relief valves to relieve at 260. So in other words, the operating pressure went up 10 pounds. We raised the set pressure 10 pounds.

MEMBER SIEBER: So you're still way under the design pressure?

MR. TESTA: Yes. Yes. Yes.

DR. BANERJEE: Do these relief valves latch open or do they close as the power goes back and forth, the pressure?

MR. TESTA: They basically have a set pressure. They will pop at that set pressure.

DR. BANERJEE: Right. And then--

MR. TESTA: And then they'll release and then reset.

DR. BANERJEE: At some other pressure?

MEMBER SIEBER: Will, you blow down for probably 5 percent.

MR. TESTA: Yes.

MEMBER SIEBER: It will close and then if the pressure goes up again, it'll open again at the original set pressure.

DR. BANERJEE: It doesn't factor?

MR. TESTA: No, does not.

MEMBER SIEBER: Hopefully.

MR. TESTA: Again, we've already done

this. We have operating experience on Unit 2 in the past spring outage. We've already done that modification. And we've had no issues, no problems with that.

MEMBER SIEBER: The pressure is not high and there's a lot of volume there, so --

MR. TESTA: Yes.

MEMBER SIEBER: -- it shouldn't change.

MR. MANOLERAS: The next slide, please.

We increased the CD of our main feedwater control valves. At Unit 1 we replaced the control valve trim. At Unit 2 we are replacing the feed reg valves. We did that basically to improve their operating range and also to help stabilize our steam general level control.

MEMBER SIEBER: What kind of trim did you put in Unit 1 feed reg valves? It originally had what they called the hush trim, which was about the third mod.

MR. TESTA: This is Mike Testa.

We put in hush trims on Unit 1.

MEMBER SIEBER: That's what was in there.

MR. HANLEY: This is Norm Hanley from Stone & Webster. Repeat your question, please

MEMBER SIEBER: Ten or 15 years ago it had hush trim in it and there was a lot of problems with the valve on ability to control the low flows. The valve was modified several times, all three of them were. I'm wondering what you did recently?

MR. HANLEY: The recent change really didn't modify the trims that you have in there now. It just increased the CV. The operating experience with the latest set of trims was well. So we didn't go into a redesign of the trim. It was just get us more CV so we'd get a better operating range.

DR. BANERJEE: Well, how did you get a better CV?

MR. HANLEY: Yes. We went back to the vendor. The original valves, I think, had a large of CV, about 1100. And right now we've got 1050 in there. So the valve could accommodate. So the vendor designed the CV to give us 1050 maximum and allowed us a good operating range during the power uprate. The values should operate between 75 and 80 percent open during the uprate.

MEMBER SIEBER: It seems to me the way that the plant was originally built those valves were throttled quite a bit. Since it has electric feed pumps instead of turbine drive feed pumps, turbine driven feed pumps have basically a constant differential across the reg valve. With electric pumps at low loads there's a big pressure drop there. It's very hard on the valves; that's why the valves were modified several times to try to tone down the energy dissertation. After the hush trim was installed, that was pretty much the end of the feed reg valve problem.

MR. HANLEY: In fact, we just installed them in Unit 1 and we did a start up and the valve behaved very well during start up.

CHAIRMAN DENNING: Be sure to speak into the mike.

MR. HANLEY: All right.

MR. SENA: This is Pete Sena.

Just one item, Mr. Sieber, that the operating crew from this last start up at Unit 1 did comment that the feed reg valve control was the best they had seen at low power operations for start up. There were no anomalies.

MR. MANOLERAS: Okay. Jim had already discussed the replacement of the rotor and the rewind of the starter.

We additionally modified our heater drain control valves at both units to increase operating range and improve capacity. And we replaced our instrument replacements for main steam and feedwater flow for the higher flow ranges that we'll discuss later in the safety analysis presentation.

CHAIRMAN DENNING: Before you move on to that, I do have a little digression. And that is regards to sump blockage. At some point, I presume in the near future, you're going to be making changes or can you tell us what the status is of that?

MR. MANOLERAS: Sure.

CHAIRMAN DENNING: And what the character of the changes will be and when they'll occur.

MR. MANOLERAS: Sure. We currently have about 120 square foot sumps. We're going to be expanding those sumps by a factor of at least 10. We are going to put much larger passage strainers in at Unit 1 and Unit 2. We intend to install the passive strainer system at Unit 1 in the upcoming outage and at Unit 1 in our next outage. We will also install that passage system at Unit 1.

We are currently doing the analysis associated with the strainer design, putting them in the actual mix of the insulation and boric acid, the mix, doing the testing of our strainer design to make sure that all the assumptions that we put into the analysis are put as far as DP across the strainers and whatnot. So we're going right down the path of the GSI-191 requirements.

CHAIRMAN DENNING: So the change for Unit 2 it will occur prior to the power uprate, is that true?

MR. MANOLERAS: It's going to be installed in our next outage, the physical modifications to the sump, which our next outage is when we intend to begin our escalation and our power uprate.

CHAIRMAN DENNING: Whereas in Unit 1, of course, it would follow?

MR. MANOLERAS: Unit 1 we intend to perform a mid-cycle uprate and our next refueling outage before we went to the full power uprate, we would have the new sump in.

CHAIRMAN DENNING: Yes. And what kind of thermal insulation do you currently have?

MR. MANOLERAS: We have several types of thermal insulation. We have a metal-reflective. The majority of our containment we do have metal-reflective. We also have a material it's called, it's abbreviated name is CALSIL. It's a material that is like a plaster of Paris type of material that encapsulated with --

CHAIRMAN DENNING: We're familiar with it.

MR. MANOLERAS: Okay. So we have some of that.

And we have several other types of insulation also.

DR. BANERJEE: Do you have NUKON?

MR. MANOLERAS: Pardon me?

DR. BANERJEE: NUKON?

MR. MANOLERAS: NUKON? That's a term that I am not familiar with. So I don't want to say that we don't, but it's not a prevalent use of material in our containment.

CHAIRMAN DENNING: You don't have a fiberglass?

MR. MANOLERAS: Fiberglass?

CHAIRMAN DENNING: Fiberglass? Fiberglass mats in any places.

DR. BANERJEE: Fibrous material?

MEMBER SIEBER: Yes, they're like blankets

MR. MANOLERAS: Yes. We don't have significant quantities of any fibrous material. We would have very limited fibrous material, maybe in an application like around a loop stop valve where we would have -- and I'm talking very, very small quantities of that where we would have some space limitations. Like we would pack it in around a valve, but it would be in very small quantities. And what we're going to do is in each refueling outage we're going target and take a hard look at that material to see if we can get it out of there and replace with metal reflective.

DR. BANERJEE: What are you insulating your steam generators with?

MR. MANOLERAS: The replacement steam generators? We replaced the CALSIL associated with those steam generators and put metal reflective in during this last outage in every area that we could.

DR. BANERJEE: All the new steam generators will have metal reflective?

MR. MANOLERAS: That's correct.

MEMBER SIEBER: Unit 1.

MR. MANOLERAS: In Unit 1

CHAIRMAN DENNING: At Unit 1.

MR. MANOLERAS: When we replaced our steam generators -- to make sure we're very clear. At Unit 1 when we replaced our steam generators we put in metal reflective insulation and we took out those materials that have been identified in that GSI-191.

CHAIRMAN DENNING: Will there be a future replacement of steam generators at Unit 2 or how much margin do you still have there?

MR. MANOLERAS: We have significant tube plugging margin at Unit 2. I'm sure that in our long range plan that's something that we'll look at. But at the present time we have not targeted that replacement. We have significant margin at Unit 2.

CHAIRMAN DENNING: And plant life extension is still to come?

MR. MANOLERAS: That's correct. We are currently working on what we term to be a license renewal submittal.

DR. BANERJEE: How do you control pH?

MR. MANOLERAS: Our chemical addition system we currently use an additive. It's sodium hydroxide, NaOH.

DR. BANERJEE: Do you have any aluminum in the containment?

MR. MANOLERAS: Yes, we do. We keep track. We have a very detailed program to keep track of aluminum in containment so that we don't have, for example, hydrogen generation is always a big concern. So we have a very detailed program to keep track of any aluminum that we place in containment. We have very small quantities of aluminum in containment. We know where it's at.

DR. BANERJEE: Well, will you address

these issue related to the sump and the change from sub-atmospheric to atmospheric pressure and all that sort of thing? Is there going to be a talk on this sometime?

MR. MANOLERAS: You know, there's actually a very detailed presentation that we've put in on the containment conversion submittal.

DR. BANERJEE: And will it be done, something?

MR. MANOLERAS: It will be done this morning, I believe, or early in the afternoon. And I believe we actually brought a slide to show our conceptual design for our new sump strainer. We actually have a picture of our sump strainer that we are currently designing.

MEMBER SIEBER: But the conversion of the containment to an atmospheric containment is already approved and implemented?

MR. MANOLERAS: That's correct. That license amendment has been approved and it has been implemented at Unit 1.

MEMBER SIEBER: Okay. Before you jump into the electrical system, when I was reading through the application in the SER, particularly the marked-up tech specs, I stumbled across a place where you are eliminating the negative rate trip?

MR. MANOLERAS: That's correct.

MEMBER SIEBER: What's that have to do with EPU or anything else, or did you figure that was just a good chance to get rid of something you didn't like?

MR. MANOLERAS: Well, you hit right on the head. The negative rate trip was not used in our plant safety analysis. Additionally, there was an owners group program to eliminate that trip. We took this opportunity to implement that. That will reduce surveillance burden for us at the station.

MEMBER SIEBER: Yes. The reason why it was in there originally, though, was in case you dropped a rod that the plant would trip before you started operating with a big imbalance in the core. There was a reason to do that. Did you change your operating procedures to tell the reactor operator to trip the plant when it gets to that condition?

MR. DURKOSH: This is Don Durkosh from Operations.

Yes, we have immediate operator actions for any dropped rod.

MEMBER SIEBER: Okay.

MR. DURKOSH: If we have more than one

dropped rod, we immediately trip the reactor.

MEMBER SIEBER: More than one?

MR. DURKOSH: More than one, that's correct. More than one.

MEMBER SIEBER: So what kind of offset do you get if you just drop one rod all the way in in a critical area, do you know? Has anybody done those calculations? That's why we had the trip so you wouldn't have to do the calculation.

MR. MURTAGH: This is Brian Murtagh from Design Engineering.

The Westinghouse WCAP that evaluated the elimination of the negative rate trip essentially, from what I remember, it was if you evaluated the most reactive rod worth and that were to trip, you would still not be tripping on negative rate. So because we do not credit that in the safety analysis, that's why it was eliminated.

MEMBER SIEBER: Okay. But that's different for every cycle. The Westinghouse WCAP was done for the envelop of cores that you could design and could put into that kind of a plan. I take it during the reload safety evaluation that's analyzed again?

MR. PENKROT: This is Jack Penkrot from

Westinghouse.

We do evaluate the dropped rod.

MEMBER SIEBER: Okay.

MR. PENKROT: For all the values up to 1,000 pcm. Whenever the negative rate trip was eliminated, we increased the span that we evaluated from zero to 500 to zero to 1,000. We're able to show that peaking factors are adequate to handle any dropped rod.

MEMBER SIEBER: Do you know the number and the date of the WCAP so I could read it?

MR. PENKROT: I don't have that information.

MEMBER SIEBER: Well, could you get it?

MR. PENKROT: Oh, yes. Sure.

MEMBER MAYNARD: This trip has been eliminated at a number of plants. In fact, for most plants most rods, a single rod, wouldn't give you the negative rate trip anyway. But you have procedures for recovering that rod --

MEMBER SIEBER: Yes, I know.

MEMBER MAYNARD: -- that limit. You can't just pull it right back out and go to operating. So you do have an off normal procedure that controls the recovery from that to keep you within your safety analysis.

MEMBER SIEBER: I'd still like to read the WCAP.

I was just trying to figure why it was stuck in with all this other stuff as opposed to standing out there by itself because it really is not related to EPU or the containment change or alternate source term or anything else. It's just out there.

MR. MURTAGH: Mr. Sieber, this is Brian Murtagh again.

I can certainly get you that WCAP, a copy of the WCAP.

MEMBER SIEBER: Well, we probably have it. If the Staff's approved it, it's here. All I need is the number. It'll be in our file.

MR. MURTAGH: Okay. We'll do our best to try to find that number.

MEMBER SIEBER: If you want to give it to me, that's even better. You know, I'm in love with paper. You know, I get tons of it every week.

CHAIRMAN DENNING: Thank you.

MR. MANOLERAS: Yes. I believe Chris --

MR. McHUGH: Chris McHugh from Westinghouse.

I have that number on my laptop. I'll

look it up and give it to you in a couple of minutes.

MEMBER SIEBER: Thanks.

MR. MANOLERAS: Thank you, Chris.

Any further discussion before I move on to electrical system?

We added the slide here to discuss the electric system impacts, the actual system impacts because of the power uprate were actually extremely minimal. I brought Mahesh Patel, as I mentioned before, in case any questions are beyond me and we'll have Mahesh answer those.

Our initial electrical system design is robust. We basically took a look at all of our electrical components. We looked at our Unit 1 transformer. We did not have to do any upgrades to our Unit 1 transformer.

Our Unit 2 transformer we had to upgrade that cooling system. And we did upgrade that cooling system. We have several cycles of operation now with that transformer and that cooling system. And the modification packages that we did make basically had their intended results. So our cooling system for our transfer has been upgraded.

Our isophased bus duct, one of the issues is OE and the industry looked as isophased bus duct temperatures. We went out and did extensive maintenance our bus duct cooling systems at both units to make sure that the material condition of those cooling systems -- material condition was there. We did not require any modification packages to those cooling systems.

We did install temperature indicators in those cooling systems so that we can do operator rounds and ensure that the bus duct cooling system meets its performance.

We obviously have operating limits on our grid voltage, which we did not have to change in reactive loads to look at post-trip voltages on our buses. We did not have to make any modifications to any of those limits because of the uprate.

Our grid we did detailed grid stability studies and Beaver Valley can both receive and accept trips on the grid without any impact. And we did not effect our 4-hour station blackout coping study because of the uprate.

MEMBER SIEBER: In Unit 1 are you replacing the main unit transformer or are you going to use the one that's still there?

MR. MANOLERAS: We're going to use the existing transformer.

MEMBER SIEBER: You know that that had faults in it a couple of times?

MR. MANOLERAS: We have had to replace that transformer. We had an inadvertent spraydown of that transformer several years ago and it was replaced, as you remember.

MEMBER SIEBER: Well, the replacement transformer, the internal impedance was such that it represented an unusual condition on the grid. I presume that you know that.

MR. MANOLERAS: Yes, we do.

MEMBER SIEBER: But it called into question the breaker capacity if you had to trip that transformer free from the grid interrupting capacity.

MR. MANOLERAS: Mahesh Patel.

MR. PATEL: Yes. This is Mahesh Patel.

When we had a fault on the original transformer, we had it built with a little bit higher than the previous transformer. And we evaluated the breaker capacity and that reduce the fault coming from the system. And that makes the breaker capacity. And the newer transformer is rated is 1058 MBA at 65 degree temperature rise.

MEMBER SIEBER: Okay. Thank you.

MR. MANOLERAS: The next slide, please.

Yes. In this last slide I'd like to just go over some of the industry OE and things we looked at. Each specific presenter will discuss the specific OE in his area.

We looked at, obviously, vibration issues. We talked about staking the condenser. We looked at things like the turbine control system running with valves wide opened. We looked at the isophase bus duct cooling capacity and transformer cooling. And Jim discussed earlier we installed the leading edge technology -- the leading edge flow meter for measurement uncertainties.

Each presenter will discuss OE in his particular area.

If there are no additional questions, I would like to introduce A.R. Burger, our fuels analyst.

MR. BURGER: Thank you, Mark.

Good morning.

As Mark indicated, my name is A.R. Burger. I'm currently the supervisor of core design and physics support. And I'm responsible currently for the design oversight for not only Beaver Valley, but also the Perry and also Davis-Besse unit.

I have supporting person Jack Penkrot.

He's a Westinghouse core designer. He's done core design for both Beaver Valley units for quite a few years.

To give you a little background, I started out in '82 as a reactor engineer down at Beaver Valley. Starts physics testing at Unit 2 and power central testing. Moved on to the fuel procurement and contract administration in the '90s. And '98 to 2004 I became the core design, reload design coordinator for Beaver Valley interfacing with all the contract administration in implementing the core designs. And currently I'm in the supervisor position.

I've been involved in EPU since the inception back in 2000 and so we've preparing in the core design area for that.

What I'm going to touch upon is the fuel design and the core design aspects.

This represents the current design that we have Beaver Valley. It's called the robust fuel assembly. It's the same array, 17 by 17 as the previous, which was a Vantage 5H that we had prior to the RSA. We maintained the enrichment, the geometric fuel geometry, the cladding, the loading of the uranium, axial blanket height; all that has remained the same.

The changes with the RFA that we've put in, we have six cycles operating history on the RFA. We implemented back at Unit 1 starting with cycle 15 in 2001 and that Beaver Valley introduced in cycle 10 2002. We did that for several reasons, one being the uprate coming. We saw that coming and so we wanted to get in to look at the RFA design. There's intermediate flow mixers on the top three spans. That will give you GMD margin that we would implement to give us for the uprate.

MEMBER SIEBER: You have to change the pressure drop across the core?

MR. BURGER: Yes.

MEMBER SIEBER: By how much?

MR. BURGER: There was a couple of pounds difference.

MEMBER SIEBER: That's pretty much.

MR. BURGER: And that's why you have a transition core penalty in that time. We've now got fuel, RFAs in the entire core so we have a whole core of that. We don't have any transition penalty and things like that going on.

MEMBER SIEBER: Well, you have flow distribution problems when you have a mixed core.

MR. BURGER: Right.

MEMBER SIEBER: On the other hand it seems to me the core flow went up instead of down in your list of parameters. And I would expect it would have gone down with this kind of fuel by a little bit.

MR. BURGER: Well, they're going to go into that in the safety valve section.

MEMBER SIEBER: The pressure drop across the steam generators, the new steam generators, is less, right? Is that true? Less than the Model 51s? 54 is less DP than Model 51, is that true?

MR. BURGER: Excuse me. Could you repeat the question, please?

MEMBER SIEBER: Is the pressure drop across the new steam generators, the Model 54, less than the pressure drop across the old steam generators, which is Model 51?

MR. HALL: Yes. This is Jeff Hall, Westinghouse.

That's correct. The Unit 2 generators are Model 51.

MEMBER SIEBER: So you end up with higher DP across the core, lower DP across the steam generators and an overall slight increase in flow for the whole system?

MR. HALL: That's correct.

MEMBER SIEBER: Okay. You just moved the DPs around? Okay. Thanks.

CHAIRMAN DENNING: But of course they would be different for Unit 1 and Unit 2 then?

MEMBER SIEBER: Yes, they are right now because they haven't replaced steam generators in Unit 2.

MEMBER MAYNARD: Well, you'll also be operating at a little bit different RCS temperature, won't you, for your uprated condition?

MEMBER SIEBER: Well, yes. And that comes about because of the change in flow and the change in materials and the change in surface.

MR. BURGER: You have the 576.2 plus or minus a couple of degrees of where we're at currently for the uprate.

MEMBER SIEBER: Right.

MR. BURGER: And they'll go into that in the safety analysis section where we're targeting to go for two and a half for each unit.

MEMBER SIEBER: And your hot leg trip is what? 617, something like that? They would normally be operating at about 610 or 611 on the hot leg?

MR. BURGER: On the hot leg, yes.

MEMBER SIEBER: Okay.

MR. FREDERICK: This is Ken Frederick.

Yes, that's correct, Jack. We'll go over that later in my slides.

MEMBER SIEBER: Well, it sounds like it's the same as Ginna. Same core parameter set.

MR. FREDERICK: In terms of the temperatures, yes, it's very similar.

DR. BANERJEE: Was there any DNB testing done on a prototype bundle or something?

MR. BURGER: Yes, there were supposedly tests done for the RFA by Westinghouse when they originally came out with them in 2002 and 2001. The RFA has actually been out in the industry for quite a few years.

MEMBER SIEBER: Yes.

MR. BURGER: There's 33 plants operating with the RFA fuel design.

DR. BANERJEE: What are these mixes like that give you better performance?

MR. BURGER: They just provide extra flow mixing --

DR. BANERJEE: What are these mixes?

MR. BURGER: They're just an extra grid that's put between the upper grid span. You'll notice they're a little bit thinner than the standard grid and, again, they're must meant to get flow mixing into the assembly so that that's all they're there for. They provide a little bit more structural integrity for the assembly also, a little bit more stiffer assembly.

MEMBER MAYNARD: They just have little pads in them that kind of redirect flow and mix the flow right?

MR. BURGER: Mix the flow right.

MEMBER SIEBER: In a mixed core there are some grids that don't contact the adjacent fuel assembly grid. So from the seismic standpoint it's meaningless.

MR. BURGER: Yes. There is no impact on the seismic parameters.

DR. BANERJEE: And these tests were done in a flow loop they had with heaters?

MR. BURGER: That's right.

DR. BANERJEE: Electrical heaters?

MR. BURGER: I believe they were, yes. The VIPRE loop that they use for Westinghouse.

MR. CARUSO: Yes.

MEMBER SIEBER: Yes.

MR. CARUSO: Westinghouse has a test loop that they run down in Columbia.

MR. BURGER: VIPRE loop down there that they run.

MEMBER SIEBER: Yes. They've been doing that for years.

What correlation are they on now? It used to be --

MR. BURGER: We'll go into that. There's a WRB-2M correlation that they'll be using for the RFA and we'll be implementing that with the uprate. Right now we're not utilizing it. But when we uprate, we'll implement the WRB-2M. And, again, they'll go into that in the safety analysis.

MEMBER SIEBER: And here you can't have a mixed core to implement that correlation?

MR. BURGER: Right. We were going to implement an older design, put it in there. We have to go and use the other correlations which are still applicable.

MEMBER SIEBER: Right.

MR. BURGER: When we originally did the analysis back in 2000 we were going to have a mixed core, but it's delayed enough that we now have a full core of RFAs, so we won't need that.

MEMBER SIEBER: Well, you have to go to the most conservative correlation that you have.

MR. BURGER: Right.

DR. BANERJEE: So the increased power is accommodated by --

MR. BURGER: Why don't we go to the next slide and that will show.

DR. BANERJEE: This increase in DNB?

MR. BURGER: We'll let into it, after this one. This one will show you that the DNB margin and we're going to use the WRB-2M correlation, as I mentioned, for the IFMs being in there. The RFA also, as I mentioned, provides a better grid design for grid-to-rod fretting issues. Beaver Valley and the industry had had issues with grid-to-rod fretting and so we went to that RFA design early on for fuel failures to get rid of those.

We also at that time, there was issues with incomplete rod insertion in the industry. So the RFA provides a slightly increased the I2 giving a stiffer assembly and more margin --

MEMBER SIEBER: A larger diameter guide, too?

MR. BURGER: Yes. The IB stayed the same and the OD increased slightly.

MEMBER SIEBER: Okay. And I take the grid-to-rod fretting you're using the -- you have two dimples and two springs made out of Zircaloy. And those springs as the become irradiated, they relax.

MR. BURGER: Right. Correct.

MEMBER SIEBER: To the point where they aren't springs anymore?

MR. BURGER: Yes. They redesigned those assemblies so they had more contact surface area with the springs. And we have not had any grid-to-rod fretting with those assemblies and we have three cycles of operation. So they basically have gone through a full lifetime of those.

MEMBER SIEBER: That wasn't really an issue at that plant anyway.

MR. BURGER: What? At Beaver Valley?

MEMBER SIEBER: Yes.

MR. BURGER: Yes. We had grid-to-rod fretting issues with the 5H, yes.

MEMBER SIEBER: Oh, okay.

MR. BURGER: Yes. We had fuel failures associated with that.

DR. BANERJEE: But to get the increased power out, does the surface area in contact with the coolant increase or not?

MR. BURGER: No. We'll go to the next slide. What we'll do is we did conceptual core designs for the uprate conditions. We did that both with the Westinghouse codes, the ANC codes. We also run in-house down at our offices. Basically to get the increased power out we're going to go from equilibrium to core cycles of 18,800, 20,200.

We have had cycles up above 20,200 just because of the way the outages were scheduled. Beaver Valley Unit 2 cycle 10 was 20,400. So we have had cores where there's much energy as we'll be doing for the uprates.

Basically your linear heat generation rate's going to go up. So the fuels all stayed the same on the surface area and everything else. Just put --

DR. BANERJEE: So your heat flux goes up?

MR. BURGER: Right. And it's in the same vein as the others that we mentioned earlier, kilowatt per foot is in that same range --

DR. BANERJEE: So what allows you to get more heat out of the same surface area fuel?

MEMBER SIEBER: Higher temperature.

MR. BURGER: Higher temperature. Yes.

DR. BANERJEE: No, no. I mean from the point of view of limits?

MR. BURGER: Our peaking factors will

remain the same.

MEMBER SIEBER: You got closer to the point of 200.

DR. BANERJEE: What?

MR. BURGER: The peaking factors were to remain the same. What we did was to get more margin on the fuel is we put in the IFM, so that gives DNB margin and --

DR. BANERJEE: So you get your DNB margin by doing better mixing?

MR. BURGER: Right. In the hottest --

DR. BANERJEE: And this is a fairly well understood process?

MR. BURGER: Yes.

DR. BANERJEE: How much increase in DNB do you get?

MR. BURGER: About a 20 percent increase.

DR. BANERJEE: Remarkable. And what about the LOCA limits?

MR. BURGER: We'll go into that later in the safety analysis and they'll actually show you the markups of where the DNB margin limit, where the correlation is, how much safety margin in. And we'll go into that in the safety analysis.

DR. BANERJEE: So basically you have the

same surface area fuel, the same subdivision and you're getting 10 percent more power?

MEMBER SIEBER: Yes.

DR. BANERJEE: By doing something to the DNB limit and the LOCA limits?

MEMBER SIEBER: Well --

DR. BANERJEE: Is that a correct statement?

MEMBER SIEBER: Well, there's a couple of effects going on. The other thing that gets effected is the number of rods that have an increased peak clad temperature during a LOCA, and usually with an improved core design the approach to the 2200 degrees doesn't change very much, but the number of rods who make that approach does change because you're flattening the power distribution.

MR. BURGER: Right. And you'll see that, as we said, there's going to be 64 more feet assemblies. So to get that extra power out, you'll need more feed assemblies to go into the core. So that's where you're getting extra power; you're going to spread that power out over --

MEMBER SIEBER: That's where you get the neutrons from.

DR. BANERJEE: You're not increasing the

surface area of the fuel? You're just bringing in fresher fuel?

MR. BURGER: Right. Distribute the burnup along the assembly --

DR. BANERJEE: So that means you get a high heat flux, too, right? So the issue really, and hope you'll address is, is to understand how you can get more power out of the same fuel, basically the same fuel surface area. Maybe it's by sharpening the pencils and doing a few experiments, but we want to be convinced that this is really not. Maybe other people have done that, but you would have to do it at some point.

MR. FU: Okay. This Chun Fu, Westinghouse, thermal hydraulic design.

So basically you have IFM, it enhance your mixing an in an analysis area we have WRB-2M correlation, which give you 20 percent or even a little more than 20 percent in the margin. So you will see that.

DR. BANERJEE: Yes, we'll look at it. And the basis for it.

CHAIRMAN DENNING: This is probably an irrelevant question, but why didn't you decide to go to higher burnups?

MR. BURGER: Higher burnups?

CHAIRMAN DENNING: Yes.

MR. BURGER: The average actually discharge we're putting in four more assemblies. You'll spread the burnup among those. So the average discharge on the assemblies will remain about the same. So you'll just put that burnup on more assemblies. But you really, the overall will be in the 50,000.

CHAIRMAN DENNING: What's your refueling cycle then?

MR. BURGER: We're on 18 month refueling cycles.

CHAIRMAN DENNING: You're on 18 month refueling cycle?

MEMBER SIEBER: These are cycle burnups as opposed to assembly burnups?

MR. BURGER: Discharge assembly will be in the 50,000 --

MEMBER SIEBER: Right.

CHAIRMAN DENNING: That's what I didn't understand.

MEMBER SIEBER: Which is a moderate. It's sort of in the middle of where everybody's running.

MR. BURGER: Right. Yes. And there's

other plants that are operating at 5.69 and 2900 and they're in the similar area.

MEMBER SIEBER: Right.

MR. BURGER: Next slide.

Our current maximum riching is 5 weight percent. We currently put in a split four of usually 495 right now and 46 enrichment, so it'll be no change to the maximum enrichment that we'll see.

With T_{avg} remaining approximately the same plus or minus 2 degrees of the current, you don't see a whole lot of change in the flux profile on the assemblies.

Again, we're operating with a full core of RFA, full units so we won't have any transition four penalties impacted.

And another item that we implemented was separate from the EPU was RAOC. That was basically to give more operating flexibility to the Operations. They were doing that separately but when we went to the EPU we also incorporated EPU conditions into the RAOC curves that we came up with.

We've now implemented RAOC, start up of Unit 1 here is with RAOC. So they're operating right now with RAOC at the current --

MEMBER SIEBER: That's already been

approved?

MR. BURGER: Yes, it's been approved. Right. And we're actually operating it for the first cycle right now.

MEMBER SIEBER: There are a number of other plants that have already have this.

MR. BURGER: Right. And you have a tech spec out of that one.

MEMBER SIEBER: Usually on the maximum enrichment it's the spent fuel pool that governs how high you can go.

MR. BURGER: Yes. We're currently at five weight percent for both units.

MEMBER SIEBER: Okay. Do you take burnup credit?

MR. BURGER: At Unit 1 we have Borel in the Unit 1 fuel pool and so there's distinct regions for that of where the fuel goes.

Unit 2 we have Borelfex. We're not crediting the Borelfex in there. So we credit the soluble boron in there. And we're trying to get a rerack in there for Unit 2 to get rid of the Borel. Also, to get more room in the spent fuel pool. And that analysis will be done in the late 2009/2010 area.

MEMBER SIEBER: Do you have enough extra

spaces to wait that long?

MR. BURGER: Apparently we can go that long. We have submittal later this year for spent fuel criticality analysis to maybe get a better checkerboard pattern out of that and maximize those areas in the pool.

MEMBER SIEBER: Well, the checkerboard pattern ought to spread out the deposition of heat modes, too.

MR. BURGER: Right. Exactly.

MEMBER SIEBER: For obvious reasons. Okay.

MR. BURGER: And that's all I had in the fuel and core design area.

CHAIRMAN DENNING: I think there is something we want to pursue just a little bit here. Because obviously we're on a tight time schedule related to when we're going to have our full Committee. And I see an issue here related to the change in the DNB correlation associated with that mixing. And I can see Sanjoy is ready to jump onto this issue.

I'm wondering how quickly could we get some information on the validation of this revision to the DNB model? And presumably Westinghouse has some results.

MR. BURGER: Yes. That's already been previously approved the correlation. And it's already in use.

CHAIRMAN DENNING: Okay. So that's the other element I wanted to --

MEMBER SIEBER: I think there's a WCAP on that one.

MR. BURGER: Yes, there's a WCAP out there for the WRB-2M right. And then we're applying it now with the use of the VIPRE code and --

MEMBER SIEBER: Maybe we could just get a copy of the WCAP?

MR. CARUSO: I can give you a copy of the WCAP.

MEMBER SIEBER: Oh, okay.

DR. BANERJEE: And it's been applied to this specific fuel?

MR. BURGER: Five or six years ago, yes.

DR. BANERJEE: To this specific fuel design?

MR. BURGER: Yes.

DR. BANERJEE: And at these ratings?

MR. BURGER: Yes.

DR. BANERJEE: Where?

MEMBER SIEBER: Yes, before they sell it they usually have the correlation and have it approved.

MR. CARUSO: The plants are using this that have not done the uprate. Haven't done uprates. They just use it to increase margin to improve their fuel performance. There's a lot of reasons why they would want to use that are --

DR. BANERJEE: So I think we could just review what's being done right now.

MR. CARUSO: I think I can get a copy. I know the guy who did the review.

DR. BANERJEE: Review the review?

MR. CARUSO: We could talk about that offline. But that's not hard to get for you.

DR. BANERJEE: Okay.

CHAIRMAN DENNING: Okay. Very good. Thank you very much.

We're now going to take a 15 minute break and we start up again at five after 10:00.

(Whereupon, at 9:52 a.m. off the record until 10:09 a.m.)

CHAIRMAN DENNING: Okay.   We're now back in session. And we're going to start up with Mr. Frederick on safety analysis.

MR. FREDERICK: I wanted to thank the Committee for allowing us the opportunity to come and talk to you.

As the slide says, my name is Ken Frederick I'm the lead safety analyst at Beaver Valley. By background I've worked at Beaver Valley for 27 years, most of that time has been spent in the engineering department, only a few years in the operations.

For the last five years I've been assigned to the uprate project and also the other projects that we mentioned here, the containment conversion and the best estimate LOCA.

Next slide.

Just to give you a brief objective for what we consider the safety analysis of the plant. First of all, we want to demonstrate that we have compliance with all the regulatory limits and the acceptance criteria . And also we want to show that Beaver Valley has adequate safety margins at the EPU conditions.

Next slide.

So basically we'll be talking about the specific analysis areas that are listed here as well as some of the methodologies and the setpoint changes and design parameters associated with the EPU conditions.

This slide shows the design parameters for the uprate condition as well as the current operations. Basically here we're showing that the mass flow through the reactor essentially is unchanged. The thermal design flow, which is the tech spec value which is in volumetric units gallons per minute stays the same. So in order to get increased power out of the core, we have to increase the enthalpy rise across the core. So you see an increase in the hot leg temperature and a slight decrease in the cold leg temperatures.

CHAIRMAN DENNING: And the difference between EPU low and EPU high is what?

MR. FREDERICK: We've analyzed a range for T_{avg}. The low temperature being 566.2 and the upper end is 580 degrees.

CHAIRMAN DENNING: And you would expect at different times to be operating throughout that range depending upon what was?

MR. FREDERICK: Yes, we have target values. And you want to pull up the backup slide?

This slide shows the target values that we're intending to operate at, although we could revise the T_{avg} parameter in that range that we have the analyzed, 566.2 to 580.

For Unit 1 you can see T_{avg} as compared to the current operation will go up a little less than 2 degrees. And the hot leg temperature will go up about 4 degrees.

And this is basically what we targeted and we've optimized our turbine, our replacement high pressure turbine for this steam pressure for the EPU condition. Again, depending on our new generators, our new replacement generators operate. And they do seem to match up pretty well with the pre-EPU estimate there of 822 psia. They're pretty much right on that. So we probably won't be needing to make any adjustments in T_{avg} but if --

MEMBER WALLIS: What do you mean psia?

MR. FREDERICK: Pardon me?

MEMBER WALLIS: Did you adjust for atmospheric everyday? Don't you measure psig?

MR. FREDERICK: Yes. We actually measured 810 psig is what we're seeing out of the replacement generators.

Move on to the next slide it shows the Unit 2 target values. In Unit 2 we're actually intending to reduce T_{avg} a couple of degrees. And the intent here is to try and maintain the hot leg temperature at approximately where we are now, which is at 609. That will minimize any impacts on the materials.

MEMBER MAYNARD: Now Unit 2 is the one that still has the 600 --

MR. FREDERICK: Yes.

MEMBER MAYNARD: Is that the main reason you're trying to keep the --

MR. FREDERICK: That's correct.

MEMBER SIEBER: Unit 2 has 600? Okay.

MR. FREDERICK: And again, a T_{avg} results in a reduced steam pressure here. So when we replace our high pressure turbine in Unit 2, we'll be targeting a lower steam pressure for the optimum design in that turbine.

In the area of safety setpoints, we have made a couple of changes to reactor trip setpoints. Primarily these are the delta T trips, the overpressure and over temperature delta T trips.

We've reduced the primary setpoint for these trips. If you're familiar with the trips, that's the K_1 and K_4 terms.

We've also added some filters on the equations, the functional equations. I can pull up a slide. You're looking puzzled, so we'll pull it up here.

MEMBER WALLIS: I'm puzzled.

MR. FREDERICK: This is the actual equation that models this trip. And again, that's all done electronically.

The K_1 term for the OT delta T trip and the K_4 term for the OPR, the primary trip and then the rest of the terms there are basically lag and lead functions and also some adjustments based on actual temperature and pressure conditions.

MEMBER WALLIS: How long are these times typically that are in the --

MR. MURTAGH: This is Brian Murtagh.

The filtering is about 6 seconds for the T_{avg} and delta T filters. All the other time constraints are typically for the lead lag function would be 30 over 4. Tile 1 and tile 2 would be tile 130, tile 24.

MR. FREDERICK: Does that answer your question?

MEMBER WALLIS: Yes. I was just going to get an order of magnitude of the tiles to see what sort of times you're dealing with.

MR. FREDERICK: Right. The filters,

again, were added essentially to give us additional operating margin so we don't see inadvertent trips from temperature spikes and that type of thing.

MEMBER WALLIS: To wipe out the bouncing array?

MR. FREDERICK: The noise, right. Correct. And with the reduced trip setpoint and the additional filters we're not really losing any operating margins.

Some other --

DR. BANERJEE: Does this sort of take out some specific frequency component and above? When looking at this equation I can't tell anything. So what is the frequency cut off --

MR. FREDERICK: Brian?

MR. MURTAGH: Well, if you were to look at it in terms of a low pass filter --

DR. BANERJEE: Yes.

MR. MURTAGH: -- then the cut of frequency would be the inverse of one over 6 seconds, say.

DR. BANERJEE: One over 6 seconds?

MR. MURTAGH: Yes.

DR. BANERJEE: Why 6 seconds? Why not 10, why not 3?

MR. MURTAGH: Well, I believe probably as much as you increase the filtering, you're going to have to decrease the setpoints. Okay. So it's an optimization of how you want the circuit to function. You know, it's a trade off between that protects part of it --

MEMBER WALLIS: If it's too long, then you don't respond quickly enough.

MR. MURTAGH: Right.

MEMBER WALLIS: And if it's too short, you respond to every little transient.

MR. MURTAGH: And if it doesn't respond quickly enough, you'll have to reduce the set point.

DR. BANERJEE: So is this judgment call? Is it a judgment call or is it an optimization? Optimization assumes there's a function you're trying to maximize, right?

MR. MURTAGH: Yes. I believe the code for it is OptiMax code -- OptoX code used by Westinghouse.

DR. BANERJEE: What is it you're trying to optimize?

MR. DURKOSH: This is Don Durkosh.

What I wanted to point out was the time constants here. These were established many years ago at Westinghouse and they were optimized based on the plant design. And for the most part these constants have stayed pretty much the same and have been used by just about all Westinghouse plants.

As part of this project all they did was they looked at this and they tried to optimize. As Ken pointed out, what they did was they lowered the steady state trip value of small mount and by doing that they were able to add a small time delay so that if a particular noise event occurred, it wouldn't bring that channel into a partial trip condition. So it's just a small trade off as steady state versus a transient change.

DR. BANERJEE: So how small was this? What was small here?

MR. DURKOSH: Well, I don't have the numbers memorized, but I did talk to the Westinghouse and--

DR. BANERJEE: Rough terms.

MR. DURKOSH: Basically these values are representative of what other plants have. They are not out of line.

MEMBER KRESS: Don't you need some sort of measure of the normal oscillations to do this optimization?

DR. BANERJEE: What does that mean in delta T? I can't tell that with the ratio?

MR. DURKOSH: Well, let's take the first

bullet here.

DR. BANERJEE: Yes.

MR. DURKOSH: At steady state conditions for K_1, 1.259. What that means is if loop delta T got up to 25.9 percent above nominal, it would actuate. So we've lowered that value a little bit. We've reduced the steady state trip value from 25.9 percent to 24.2 percent at Unit 1. And we traded that margin off against just delaying the signal and the length of the signal that requires actuation.

DR. BANERJEE: By how much? It would be nice to have real numbers instead of percentages because I can't tell what they are looking at them. Whether there's a degree, 10 degrees, 5 degrees; what is the number?

MEMBER WALLIS: Well, I guess our interest would be --

MR. DURKOSH: The number for --

DR. BANERJEE: How many seconds, how much average --

MR. MURTAGH: The K_1 number means for your at nominal delta T that you have measured at 100 percent power. If you reach a 124 percent of that value, you will trip.

DR. BANERJEE: Right. But you know the

normal operating temperature --

MR. FREDERICK: The nominal delta T is about 60 degrees.

DR. BANERJEE: Sixty degrees?

MR. FREDERICK: Right.

DR. BANERJEE: So you've reduced that by how many degrees?

MR. FREDERICK: The trip?

MR. MURTAGH: The trip will be 124 percent of the nominal value.

MR. FREDERICK: Well, 2 percent of 60 is roughly one degree.

DR. BANERJEE: This is my head, I need a calculator.

MR. FREDERICK: It's roughly 1 degree delta.

DR. BANERJEE: Okay. One degree. And the time?

MR. FREDERICK: I'm not sure. Brian, do you know what the time change was? In addition to the filter, what does it --

MR. MURTAGH: Well, there's no direct correlation between filtering and --

MEMBER WALLIS: The only thing that matters to me really is the impact of these things on the plant.

DR. BANERJEE: Yes. So one degree change is a small change, but that has given you a big change in the time available?

MR. MURTAGH: Has that given you a big change?

DR. BANERJEE: How much?

MR. MURTAGH: The time delay is going to be built into the safety analysis where the function is no longer credited as an immediate trip. It would be assumed to be delayed in a safety analysis.

DR. BANERJEE: By how much?

MR. FREDERICK: If I understand what you're asking, we'll get that number for you.

DR. BANERJEE: You know, I just want to get a feel for does 1 degree change in this give you twice as much time or is it --

MR. FREDERICK: Yes, I understand.

DR. BANERJEE: -- five percent, or nothing?

MR. FREDERICK: We'll have to get back to you on that.

MEMBER SIEBER: Well, there's an inherent time delay anyway.

DR. BANERJEE: If it's small, it's

irrelevant. Yes.

MEMBER SIEBER: That's because of the instrument response.

DR. BANERJEE: Yes.

MEMBER MAYNARD: But it's still a trade off, but you're not approaching any limits anymore. You're trading off the point at which it trips or a time. It's still within that time. It can't exceed any of your safety analysis requirements or anything. So it's not changing a limit that you're going to get to.

MEMBER SIEBER: Right.

DR. BANERJEE: Anyway, appreciate having the time.

MEMBER WALLIS: And I think our main message should be it changes to what? What's the adverse consequence because we haven't said anything about the consequence here.

MR. FREDERICK: Right. Yes, the delta T trips are primarily DNBR protection trips --

MEMBER WALLIS: So the thing is by changing this, have you reduced the DNBR margin significantly? That's what really we should look at?

MR. FREDERICK: Yes.

MEMBER WALLIS: Maybe you could tell us--

MR. FREDERICK: Yes, well we'll talk about that in some detail later.

MEMBER WALLIS: We'll get to that, I presume.

MR. FREDERICK: Right. Right.

MEMBER WALLIS: You heard about how we probed the last applicant on this question?

MR. FREDERICK: Yes. Yes.

MEMBER WALLIS: Thank you.

MR. FREDERICK: Okay. Let me go back to the original slide here.

Other protection system changes. We've changed the low steam generator level trip for Unit 1, and that's associated with changes in the instrument span for that replacement generator. Has a larger, narrow range span.

Again, as we talked about before, we were eliminating the flux rate trip. And that, again, was a generic approved, not associated with EPU, but included.

The containment set point changes were associated with containment conversion. Those have already been implemented. We've raised the setpoint since we've increased the normal operating pressure.

And we also at that time, we revised the low level RWST recirc setpoint. And that was --

MEMBER WALLIS: You went from a reduced pressure containment to an atmospheric, is that what happened?

MR. FREDERICK: That's correct.

MEMBER WALLIS: Why did you do that? Maybe you've explained that already, but why?

MR. FREDERICK: Yes, we can talk about it later. But primarily the reason is --

MEMBER SIEBER: To make old guys breath easier, right?

MR. FREDERICK: That is a very key factor, yes. We have an aging workforce and wearing 40 pound biopacks in containment is certainly not very comfortable. So it does add a --

MEMBER WALLIS: An aging workforce is what--maybe we should pressurize this room.

DR. BANERJEE: Oxygenate.

MR. FREDERICK: Consideration of personnel safety and we also see some other benefits in the analysis from the increased pressure. And we'll talk about that later.

DR. BANERJEE: What is the RWST level low-low setpoint lowered? What is the implication of this?

MEMBER SIEBER: I'm sure safety injection is --

MR. FREDERICK: The setpoint is where transfer from injection mode to recirc mode. And by lowering that setpoint we end up with more water in the sump whenever we do that transfer so that increased the NPSH margin for primarily the low head safety injection pumps.

DR. BANERJEE: Do you have a problem with NPSH margin?

MR. FREDERICK: Yes, we're pretty close to the limit.

DR. BANERJEE: Is that why you're doing that?

MR. FREDERICK: That was one of the reasons, yes.

DR. BANERJEE: And the water is hotter because your containment is at a higher pressure now?

MR. FREDERICK: Yes. It is slightly higher. And we'll talk about some of that in the containment portion of the --

MEMBER SIEBER: Yes, that shouldn't be by much, though.

MR. FREDERICK: Yes.

Next slide, please.

We have changed some of the control system setpoints. Again, these were just setpoint changes, none of the control schemes were function changes in the plant.

Pressurizer level is something that's programmed to T_{avg} so that the maximum or the normal operating level is a function of what T_{avg} we're operating at. So raising T_{avg} a couple of degrees will increase pressurizer level by a couple of percent of full power.

MEMBER SIEBER: Well the controller will do that, but you program it to make it happen, right?

MR. FREDERICK: Yes. There is a little rescaling involved. But, yes.

MEMBER SIEBER: I take it you've analyzed the response of the pressurizer for various transients and accidents to show that it is still of adequate size?

MR. FREDERICK: Yes. We've analyzed for the full range of accidents and also margin to trip analyses.

MEMBER SIEBER: Okay.

MR. FREDERICK: The more normal occurrences. And we'll talk about it --

MEMBER SIEBER: And the change you're

making is not that great, so it shouldn't have a big impact on the pressurizer size.

MR. FREDERICK: Right. Right.

MEMBER SIEBER: Okay.

MR. FREDERICK: We're also changing some of the steam dump. This is essentially the turbine bypass system. The control setpoints there are optimized to operate for the EPU condition.

Steam generator level again for Unit 1 with the replacement generator, we have to increase the setpoint for normal water level. Essentially it stayed the same where we were before because of the increased span on the tape settings.

DR. BANERJEE: I didn't get that last point. Why did you have to increase the --

MR. FREDERICK: The replacement steam generators, they have a 212 inch span for the narrow range. The old ones had about 144 inch range. So to get to the same level now we're at 65 percent, which before we were at 44 percent. So it's just a change based on the span.

Next slide.

MEMBER SIEBER: These slides that have the little boxes like this one to the right, that's a backup slide?

MR. FREDERICK: That's correct.

MEMBER SIEBER: Are they in this book some place?

MR. FREDERICK: No, they're not. We do have copies available.

MEMBER SIEBER: I think we would need the copies of the slides that you show?

MR. CARUSO: I have those. I'll print them up for you. I have an electronic copy of this.

MEMBER SIEBER: Oh, okay.

DR. BANERJEE: If you have an electronic copy of all this --

MEMBER SIEBER: Why don't you just give us the electronic copy and --

DR. BANERJEE: So then we just may get the electronic copy from you rather than this.

MR. CARUSO: Sure.

MR. FREDERICK: This slide basically outlines the methodologies that we used for the safety analysis. And it also shows what the current methodologies were. So for large break LOCA we are changing from the Westinghouse BASH methodology, which was Appendix K method, to the BE LOCA methodology, which uses the COBRA/TRAC code.

And as we mentioned previously, this is

the original BE LOCA methodology approved in 1996 when we started this program, ASTRUM, which is what Ginna used, wasn't approved at that time. So we're not using that.

DR. BANERJEE: Do you do these calculations yourself or somebody else does it?

MR. FREDERICK: Westinghouse has performed these calculations for us.

DR. BANERJEE: I see.

MEMBER SIEBER: You have access to their codes, though, right?

MR. FREDERICK: I have access to LOFTRAN, but not the LOCA codes. Just the non-LOCA.

DR. BANERJEE: So you sort of contract them to do this work?

MR. FREDERICK: That's correct.

DR. BANERJEE: And how much audit capability do you have of what's going on there?

MR. FREDERICK: We have reviewed all of the calculations that were done for the uprate. In other words --

DR. BANERJEE: You don't have a copy of the code to test out or anything like that?

MR. FREDERICK: Well, again, in the case of non-LOCA I do have a copy of the LOFTRAN code which

I do run. I don't have a copy of NOTRUMP or COBRA/TRAC. Our review is basically limited to making sure that they use the inputs that we specify and making sure the output looks reasonable.

As I mentioned, large break we have changed to BE LOCA. The small break still uses NOTRUMP, which is the Westinghouse small break approved methodology.

MEMBER WALLIS: Now you've changed to best estimate method. Did you try to use BASH on the power uprate?

MR. FREDERICK: No, we did not.

MEMBER WALLIS: Because I was wondering if you would be over the limit if you used it? Did you use BE LOCA because you have to because otherwise you'd--

MR. FREDERICK: It was a decision that we made to regain some margin which would help us out with the --

MEMBER WALLIS: It's so conservative. It looks like it would drive you over the limit if you gain power too much.

MR. TESTA: Ken, if I can input here. I'm Mike Testa, I'm the Project Manager at Beaver Valley.

When we first set out on this project with the extended power uprate, you know, we were going to do an extensive reanalysis. And part of that is we wanted to bring the design up to the later design codes. So that was an opportunity for us. We knew we had to redo the LOCA analysis and we choose to go to the BE LOCA methodology.

MEMBER WALLIS: And my question really was if you'd used BASH, because I'd like to compare the new with the old when you give us, say, 2190 degrees or something.

MR. TESTA: Yes. We did not run--

MEMBER WALLIS: And maybe the temperature actually goes down with the new prediction method because it's because of the method, rather than the physics.

MR. FREDERICK: Yes. But we did not run that.

MEMBER WALLIS: But I think we'll get into that later, perhaps.

DR. BANERJEE: Was there industry experience with something equivalent to BASH that suggested you should do BE LOCA?

MR. FREDERICK: Certainly the BE LOCA was known to provide better results just because of the methodology --

DR. BANERJEE: There were lower --

MEMBER SIEBER: That's correct. Yes.

DR. BANERJEE: Lower results? Better we don't know for sure.

MEMBER WALLIS: From the point of view of safety, better is higher.

DR. BANERJEE: Better results?

MEMBER SIEBER: Lower results.

MEMBER WALLIS: Because then you could back off.

MEMBER SIEBER: Well, there is a typical for BE LOCA in an SER which would -- I don't know whether that --

MR. FREDERICK: This version of BE LOCA was actually approved in 1996 and a lot of other plants have been using it.

DR. BANERJEE: Yes, but --

MEMBER SIEBER: You may want to look at that topical in the SER to determine what the equivalence, if any, there is. Because there probably isn't much of an equivalence because one uses an extreme boundaries of everything whereas BE LOCA is best estimate with uncertainty. Get a different answer.

MR. CARUSO: I believe the Committee has

written a letter on this method.

MEMBER SIEBER: I suspect they have.

MEMBER WALLIS: Well, it came up with the last applicant that they had used the Appendix K method. I think they went over 2200 degrees. BE LOCA put them way below. So it makes a big difference.

MEMBER SIEBER: Yes.

DR. BANERJEE: But going back, I just want to be -- have any of these other uprates that were listed which are somewhat similar to these used something equivalent to BASH in doing that, do you know?

MR. FREDERICK: I don't know. I'm sure that some of the older uprates would have used BASH because that was what the licensed code was at that time.

Matt, do you have any --

MR. CERRONE: Yes. Hi. My name is Matt Cerrone with Westinghouse.

All recent uprates are all done with best estimate methods for the large break accident.

DR. BANERJEE: When was the last one done with BASH?

MR. CERRONE: I don't know.

DR. BANERJEE: Was there one done with

BASH?

MR. CERRONE: I can't imagine. I mean, my experience would have it that -- basically all my experience with Westinghouse was whenever we would move to a new product or especially with uprates, the best estimate technology using COBRA/TRAC is the methodology of choice because it is capable of modeling the phenomena that's expected out of these codes for large break accidents these days.

DR. BANERJEE: Now just to follow this. The BASH number for the unuprated plant were acceptable, I take it? Now, this 10 percent increase must then give some problem with BASH, otherwise why would people go running to the best estimate.

MR. FREDERICK: I do have a slide later that shows the BASH results with current power level.

MEMBER WALLIS: I take it we're going to get into each of these in detail later on?

MR. FREDERICK: That's correct.

MEMBER WALLIS: Okay.

MEMBER KRESS: When you do the large break LOCA did you take advantage of the new break size that NRC is flirting with?

MR. FREDERICK: No, we did not.

MEMBER KRESS: You used the actual large

double winded --

MR. FREDERICK: Yes, double winded rupture.

MEMBER SIEBER: When you did the calculations for the alternate source term in your containment parameters, you used the latest DKE curve? Does BELOCA use the same DKE curve or the earlier versions that the Appendix K used?

MR. FREDERICK: BE LOCA methodology uses the 79 curve with 2 sigma, not the 71.

MEMBER SIEBER: Okay. That's the later?

MR. FREDERICK: That's correct.

For non-LOCA events we've changed the DNBR calculation methodology from THINC to VIPRE. LOFTRAN is still used for the thermal hydraulics.

In the containment area again, as part of the containment conversion submittal which was recently approved, we have gone to MAAP-DBA. Previously we used a Stone & Webster code named LOCTIC, called LOCTIC.

And again, in dose assessment area we have implemented -- we have gone to a full implementation of the alternative source term and we're also using ARCON 96 now for on-site --calculations.

Essentially this is just a list of the

non-LOCA events that we've analyzed or evaluated. These are categorized by the Standard Review Plan categories. I'm not going to read them all. You can look at them there. The next couple of slides here. In total there's 18 events in the non-LOCA area that were again looked at for EPU and these have new analyses associated with them.

MEMBER WALLIS:

You're going to give us a table of results somewhere?

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

For condition II events which comprises a majority of the non-LOCA events, the acceptance criteria are meet the DNBR limits, heat generate rate has to remain within the acceptable limits. The RCS and the secondary pressures need to stable to 110 percent of the design. And the event cannot progress to a more series level 3 or level 4 event.

DR. BANERJEE: Does this also apply for steam line breaks?

MR. FREDERICK: Yes. Well, steam line break, as we'll see, is actually a condition IV event. But when we analyze it we use condition II criteria. So it does apply, yes.

MEMBER WALLIS: Now you've seen these

slides before. Is something wrong with the screen here? Is that why it doesn't look good?

DR. BANERJEE: Yes.

MEMBER WALLIS: Why did the NRC, we designed this room and give us a far worse screen than we had before.

MEMBER KRESS: That's a good question.

MEMBER WALLIS: I think we should put that on the record.

CHAIRMAN DENNING: I don't think we're going to demand that you answer that.

MEMBER WALLIS: Well, I just want to make sure it's not just me. I mean, when you get --

MEMBER KRESS: It's not just you. Rest your eyes.

MEMBER WALLIS: It's a good slide.

MR. FREDERICK: Next slide.

The first acceptance criteria we're going to talk about is the DNBR limits. As we mentioned earlier, DNBR is calculated using approved correlations. For Beaver Valley we use three correlations, WRB-1. WRB-2M and W-3. And the application of these is essentially controlled by what conditions they're approved for and also what the operating conditions are for the analysis. And we'll get into some examples later.

Primarily WRB-2M is used because that is specifically for the RFA fuel, which we use, and for the high temperature regions of the fuel with the mixing vanes.

Something else that's used here is called revised design thermal design procedure. And that is a methodology, again an NRC approved method which takes the uncertainties on power, flow, temperature and pressure and combines those into essentially a penalty that's applied to the DNBR limits. And we'll see that again on the next slide.

One thing to mention here is that at Beaver Valley, primarily because of the change to WRB-2M and the RFA fuel we actually have 21 percent margin between what we use as a safety analysis limit and the actual design limits for the fuel. And essentially that margin is retained to give the core designer some flexibility in the reload process so that if an issue comes up or a penalty that needs to be applied and they have the flexibility to do that without having to go back and redo all the safety analysis.

So if you look at the next slide, this kind of gives you a picture of how the limits are developed. On the left is the DNBR ratio. And on the right is the corresponding limit. So 1.0 obviously is critical heat flux.

The correlation limit is actually a tech spec value and it reflects the uncertainty in the correlation that corresponds to the 95/95 confidence level.

From there we go up to 1.22, which is what we get when we add in the uncertainties associated with the initial conditions in the core for power flow, pressure and temperature.

And finally, the 1.55 is what we're using as the safety analysis limit. So in between the 1.22 and the 1.55 essentially is margin which is retained by the thermal hydraulic people in the --

MEMBER WALLIS: Now the previous applicant used 1.38.

MR. FREDERICK: That's correct.

MEMBER WALLIS: So it seems there's a lot of flexibility in what you choose to use.

MR. FREDERICK: Yes. That limit is something that is somewhat negotiated between the fuel designers and the safety analysis people within Westinghouse in this case.

MEMBER WALLIS: So should we give you high marks for having a high DNBR? More safety, presumably.

MR. FREDERICK: Yes. The limit is set high primarily because in the past we had transition core penalties which have since gone away since we're into all RFA fuel at this point. But we haven't changed the limit.

MEMBER WALLIS: I wasn't here earlier. Are you changing the fuel when you do the uprate?

MR. FREDERICK: No.

MEMBER WALLIS: Not at all?

DR. BANERJEE: But it's all RFA fuel?

MEMBER SIEBER: I guess the more important question when you talk about margins is do you have somebody in your organization who is the keeper of margins? For example, you know there are things you can do when you refuel the reactor if you don't put in the flow limiting devices, that changes the core flow significantly and trades margin around. And if you don't have a single person who is watching what the condition of the core and all the modifications to the plant and changes in operating procedures, you may be giving up margin that you would rather have someplace else, or maybe two people taking a bite out of the same margin unbeknownst to one another.

MR. FREDERICK: Right.

MEMBER SIEBER: Do you have somebody that does that?

MR. FREDERICK: Well, primarily that's me, yes. We're very aware --

MEMBER SIEBER: Do you do a good job of that?

MR. FREDERICK: I think so.

MEMBER SIEBER: You want to write that down?

MR. FREDERICK: I'm very aware of where our margins lie, particularly in terms of accident analysis, results, PCTs for LOCA events and DNBR margins. Those values are associated are actually published every time we do a reload safety analysis. So we understand what the margins are and we provide the majority of the inputs for the reload evaluation. So there's margins that have to move around or to trade off operating margins. And we're part of that process and we're aware of it.

MEMBER SIEBER: And so are you on the on-site safety committee?

MR. FREDERICK: No, I'm not.

MEMBER SIEBER: But you are the keeper of the margin.

MR. FREDERICK: Our on-site safety

committee--

MEMBER SIEBER: Do you have somebody in your organization who is on that committee?

MR. FREDERICK: We do.

MEMBER SIEBER: Okay. Since you're the keeper of the margin --

MR. FREDERICK: He sits right across from me, so --

MEMBER SIEBER: Okay.

MR. MANOLERAS: Yes, Jack. And this Mark Manoleras.

We do sit on the Core Reload Safety Process. We have a sign-off on that, a design engineering manager and Ken. We have a sign-off on that Core Reload Safety Process. We have a direct input to that process.

MEMBER SIEBER: Okay. Yes, what I concern myself with is sometimes there are subtle little changes in the operation and maintenance of the plant that can change these margins.

MR. BURGER: Yes. This A.R. Burger again.

What we do in the core design process, we have a reload project team. Ken will be part of that. We have operations training, chemistry, design engineering. What we'll do is look at that on each reload and decide: (a) what changes are being made in the plant with other items that are out there and then we'll determine where we can put our DNB margin based on what's going on in each reload.

MEMBER SIEBER: And the refueling supervisor is part of that?

MR. BURGER: Yes.

MEMBER SIEBER: Okay.

MR. FREDERICK: Can I move on? Okay.

This is a table that shows the results for events which primarily are looked at for DNBR as one of their limits. And as you can see here, some of the events use correlations other than WRB-2M. For example, the first one is a rod withdrawal from subcritical so the correlation essentially does not apply in that power range, so we used W-3 and WRB-1 which are applicable at that condition.

Also for the hot zero power steamline rupture we used W-3 for that. For similar reasons it's not a full power event.

CHAIRMAN DENNING: And the reason on the first one, the RCCA bank withdrawal was acceptable is you believe the 1.65 on the W-3 more than the WRB-1 or what's --

MR. FREDERICK: Actually, Chun, maybe you can explain this. But both of those are used in various regions of the --

MR. FU: This is Chun Fu, Westinghouse.

The used of WRB-1 correlation is because for this rod withdrawal from subcritical the similar condition is out of the applicable range of WRB-2M correlation. But we did confirm, you know, that DNB criteria is met with WRB-1 correlation.

MR. FREDERICK: I think he was asking why we used both W-3 and WRB-1.

MR. FU: Both W-3 correlation, you know, WRB-1, WRB-2M correlation is applicable only for the mixing in grid spans. So we still use W-3 for the first span just from the inlet to the first mixing grid. So W-3 is always correlation.

MR. FREDERICK: So it's the position on the fuel rod where --

MEMBER WALLIS: So this doesn't indicate two different results from two correlations for the same place?

MR. FREDERICK: That's correct.

MEMBER WALLIS: It's different places, right?

MR. FREDERICK: Yes.

As you can see here the limiting case in terms of DNBR margin is the rod withdrawal of power event. And we're going to talk about that in some more detail here in a little bit.

CHAIRMAN DENNING: How does the positive moderator coefficient impact some of these as far as if you had zero moderator coefficient versus the small positive? Is it measurable in terms of the DNBR as to what result you get?

MR. FREDERICK: Chun, could you answer that?

MR. FU: I don't know --

MR. McHUGH: This is Chris McHugh from Westinghouse.

The positive moderator temperature coefficient does show up in the analysis if you have a heat up event and you analyze the zero MTC versus a small positive, you will see a difference in the results.

To correlate that to a change in DNBR would be a function of which event you're talking about.

CHAIRMAN DENNING: But for example in this bank withdrawal of power, is that --

MR. McHUGH: In the bank withdrawal at power --

MEMBER SIEBER: It would be part of it.

MR. McHUGH: It would be a small penalty, yes.

MR. FREDERICK: As I mentioned earlier, the steamline ruptures are actually condition IV events but we do analyze them to the DNBR --

MEMBER WALLIS: Now there seem to be fewer items in this table than there were on pages 33536?

MR. FREDERICK: Yes. Again, these are primarily the events which challenge the DNBR limits.

MEMBER WALLIS: We have to assume that the other ones are milder?

MR. FREDERICK: Either they're not analyzed for DNBR because of the nature of the event would not cause DNBR to decrease or they're just not anywhere near limiting.

MEMBER WALLIS: But how do you evaluate something like uncontrolled boron dilution? Are you going to tell us that or --

MR. FREDERICK: Chris, can you answer that?

MR. McHUGH: We do an uncontrolled boron dilution calculation. We take the active mixing volume, the initial and critical boron concentrations and calculate a time that it takes to dilute it and lose shutdown --

MEMBER WALLIS: You say that the operators have enough time to take action?

MR. McHUGH: Right. We conclude that they have in excess of 15 minutes.

MEMBER WALLIS: You don't calculate any kind of adverse effect. You just assume it's avoided?

MR. McHUGH: Right.

MR. FREDERICK: Next slide.

CHAIRMAN DENNING: One more thing, and that is pre EPU what did the RCCA bank withdrawal look like.

MR. FREDERICK: I have that on that slide when we talk about that event.

CHAIRMAN DENNING: Okay.

MR. FREDERICK: One of the other key criteria for the condition II events in the RCS or primary and secondary pressure. This shows the primary pressure limits in terms of how they correspond to the ASME service level stress limits. So, for example, starting at the bottom there at 2250 is our normal operating pressure. The design pressure system is 2485 psig. For service level B, which is used for condition II events, the ASME stress limit is 1.1 times the allowable stress. Conservably, that's just taken to mean a 110 percent of the design pressure even though if you looked at every component, you may be able to exceed 110 percent of design.

Similarly for level C we use a conservative criteria for locked rotor of 120 percent. Locked rotor is a condition IV event.

For ATWS the approach taken there was to actually go and look at all the components. And the limit arrived at in that manner was 3200 psig. So that is the limits applied to ATWS events.

MEMBER WALLIS: Again, these pressures aren't all to be engaged because that's what the vessel fields, isn't it?

MR. FREDERICK: That's correct.

MEMBER WALLIS: The vessel doesn't know anything about absolute pressure.

MR. FREDERICK: The analyses --

MEMBER WALLIS: If you put it in a different containment --

MEMBER SIEBER: Do you happen to know the number where you would actually get a failure of the vessel?

DR. BANERJEE: You could have a vacuum.

MEMBER WALLIS: Never been tested, has it?

MR. FREDERICK: Yes. I don't know that

number, Jack. 3200 was based on --

MEMBER SIEBER: It's like three times 25, right?

MR. FREDERICK: Yes.

MEMBER SIEBER: Twenty-five hundred?

MEMBER WALLIS: Seven thousand psi or something like that?

MEMBER SIEBER: Yes, something like that.

MEMBER WALLIS: Because it stretches bolts before that.

MEMBER SIEBER: Well, I would be heading out of town if it was going up there.

MR. FREDERICK: This table shows the results from the events which challenge the over pressure limits. As you can see here, loss of load is a limiting event for condition II events. At 2747 for Unit 1 --

MEMBER WALLIS: That's pretty close, isn't it? That's pretty close.

MR. FREDERICK: Yes. We're going to talk about that event in more detail soon.

MEMBER WALLIS: No uncertainty? This is just one spot calculation, best estimate?

MR. FREDERICK: No. This is a very conservative analysis, and that's what we're going to demonstrate.

MEMBER WALLIS: That's why it's okay.

MR. FREDERICK: This also shows locked rotor, which again is below the 120 percent limit and the ATWS analyses for both units.

DR. BANERJEE: What were these limits before the uprate?

MR. FREDERICK: The limits have not changed.

MEMBER WALLIS: No, but what were your values?

DR. BANERJEE: I mean the peak primary pressure values?

MR. FREDERICK: I do have that for the limiting case here. The loss of load I don't have that value.

MEMBER WALLIS: You sat in on the last presentation?

MR. FREDERICK: Yes.

MEMBER WALLIS: Where I asked for a table comparing before and after?

MR. FREDERICK: Again, we do have that for all the limiting cases that we're talking about.

MEMBER WALLIS: It gives us some perspective on what's going on.

MR. FREDERICK: Yes.

DR. BANERJEE: Loss of load may be ATWS and locked rotor, only of significance of right there, the rest of them --

MEMBER SIEBER: ATWS is a service level D event.

DR. BANERJEE: Yes.

MEMBER SIEBER: And loss of load is a service level B event

MR. FREDERICK: That's correct.

MEMBER SIEBER: They're different limits, right?

DR. BANERJEE: Yes, they have the same pressure limits as well, right?

MEMBER SIEBER: Right.

MR. FREDERICK: Right.

DR. BANERJEE: But it would be interesting to see what it was before.

MR. FREDERICK: What the results were before?

DR. BANERJEE: Yes, compared to now. I mean before and after.

MR. FREDERICK: Okay. I think we have those. Do we have those, Chris, before?

MEMBER WALLIS: Yes. If they're not ready this morning, you could flash them up this afternoon.

MR. McHUGH: Right.

MR. FREDERICK: Yes.

MEMBER WALLIS: Now what limits your power uprate? Is it secondary side or is it some of the safety limits? Why don't you go to higher power uprate? Is it safety limits that limit you?

MR. TESTA: This is Mike Testa again, Beaver Valley.

When we first started the project and as we showed in the beginning presentation, we looked at where the industry was operating the Westinghouse 3 loop PWRs. And we basically are aligned with them. So when we looked at the power level, we went to 2900 NSSS power, core power and that aligned us with the other --

MEMBER WALLIS: So you looked at similar plants and what they can do?

MR. TESTA: And then of course then we looked at the modifications that we needed to perform on the balance of plant side to achieve that.

MEMBER SIEBER: How much it --

MEMBER WALLIS: But conceivably if you've gone to higher power, you might get a 2750 something loss of load.

CHAIRMAN DENNING: Well, I have a relevant question to that, and that is what -- it's not chance that the pressure has come to 2747/2746 right there. Have you modified something like a setpoint or something like that that brings you there? What is it that --

MR. FREDERICK: Yes. One of the key inputs to this analysis is the tech spec limit on the tolerance for the setpoint for the safety valves. And in the case of Unit 1 we increased that from one percent to a three percent tolerance. And Unit 2 increased from 1 to 1.6. So it does drive the results much closer to the limit. And we'll talk about that a little later.

MEMBER WALLIS: You will talk about that?

MR. SENA: And this is Pete Sena, Director of Engineer.

Again, Dr. Wallis, our goal here was to go through the non-LOCA transients, take out the two most limiting transients and then go into great detail so you can see what margins do remain. That's what's Ken is going to get to next.

MEMBER WALLIS: Thank you. That makes sense. That's sort of thing we asked for last time. So thank you.

MR. FREDERICK: This slide looks at some of the other more unique criteria. Pressurizer filling is a concern essentially for progression. If we fill the pressurizer, then the chances are we could evolve into a small break LOCA which we don't want to happen. So we look at that for some of the analysis which challenged the overfill.

As you can see there, in the limiting case the spurious SI, we do actually fill the pressurizer and we'll have a more detailed discussion on that event and what we've looked at to convince ourselves that that's okay.

Margin to hot leg saturation or no boiling in the hot leg is a criteria that's applied for feedline break, which again is a condition IV event. So this is a conservative criteria for that event. And as you can see there, we have a margin to the hot leg boiling.

MEMBER WALLIS: Loss of control you're worried about, not popping something in the pressurizer?

MR. FREDERICK: I'm sorry?

MEMBER WALLIS: The relief valve opens on the pressurizer and then it fills up?

MR. FREDERICK: Yes. The concern there is if you're passing water through a safety valve it's not really designed for --

MEMBER WALLIS: All right. But it can pass with this water?

MR. FREDERICK: Yes.

MEMBER WALLIS: Right. But you lose control, that's what you're worried about. You lose pressure control?

MR. FREDERICK: Well, our concern would be that the valve might stick open --

MEMBER WALLIS: It does happen.

MR. FREDERICK: -- which would reduce pressure, yes. Yes.

MEMBER SIEBER: You have some other problems, too. You have this huge water slug going down the discharge line to the --

MR. FREDERICK: Yes, it would also challenge the --

MEMBER SIEBER: -- to the PRT, which is not a good thing.

MEMBER MAYNARD: You have separate power operated type relief valves and code safeties?

MR. FREDERICK: Yes, we have power operated relief valves as well as code safeties.

MEMBER MAYNARD: So the idea would be that those would open up, use those before the code safeties lifted, primarily?

MR. FREDERICK: That's correct. Yes.

MEMBER MAYNARD: Yes.

MR. FREDERICK: The last even there shown is the rod ejection where fuel stored energy limit the acceptance criteria. And as shown there, we meet that limit.

Next slide, please.

Again, this is a detailed discussion on the loss of load event. Basically provide a flavor for the level of conservatism --

MEMBER WALLIS: That BTU, what is that in calories per gram.

CHAIRMAN DENNING: Calories per gram?

MR. FREDERICK: Pardon me?

MEMBER WALLIS: Usually it calories per gram that we see. What is it?

CHAIRMAN DENNING: BTU per pound on max fuel stored energy. Do you know what that is conversion into calories per gram.

MR. FREDERICK: 260 or so.

MEMBER WALLIS: Or less?

MR. FREDERICK: Chris, if you want to look it up, it's in the licensing report on that computer there, I believe.

MEMBER WALLIS: Okay. We can do that.

CHAIRMAN DENNING: We can probably handle this conversion, but given half an hour.

DR. BANERJEE: And more oxygen.

MR. FREDERICK: Again, we're going to talk about loss of load transients in detail here. And the purpose is to give you an idea of the level of conservatism that these analyses are done to.

And this event produces the highest primary and secondary pressure of the condition II events. And the results from either a loss of load off the generator or a turbine trip that is caused by other inputs.

The reactor protection for this event, we have essentially five trips there that provide protection. Two aren't credited; the high water level trip and the pressurizer. That's just a conservatism in the analysis. And the reactor trip on turbine trip which is essentially the most direct trip for this event, that's not credited because that is not considered a qualified trip since it comes out of the turbine building, which is a non-seismic building.

We do actually run two cases for this loss of load, one to look at DNBR and one to look at the pressure. We're not going to talk about the DNBR case here. It's not close to being limiting.

In the analysis we, of course, bias all the input initial condition parameters to give us the worst results. Initial pressurizer pressure and level and the RCS power flow and temperatures; these are all biased in the actual run as opposed to done separately as we do for DNBR cases.

Also, we bias the reactivity feedback and we use manual rod control for this analysis.

CHAIRMAN DENNING: These are all realistic conditions, but it's just that you happened to pick them all in combination in their worst --

MR. FREDERICK: That's correct. Their initial control system setting, for example, pressurizer level at 53 percent, 7 percent is added on to that for uncertainty. So that's our initial condition for this analysis.

We don't take any credit for any of the control systems. Now essentially there's four control system that would come into play here. You know, condenser steam dumps. We also have atmospheric steam dumps on the secondary side. On the primary side we have pressurizer pressure control through the spray. And we also have power operator relief valves which would normally open up to 100 pounds below the code safeties.

For the code safety modeling we do use the maximum setpoint allowed by the tech spec. In the case of, for example, Unit 1 that is the setpoint plus 3 percent, which is our allowed tolerance or that changes part of the EPU package.

Also in the valve modeling there's delays model in the opening and that accounts for the time that it takes to purge the water out of the loop seal. In some cases, for example Unit 1 there's an opening time associated with the valve. It's a target rock valve. And there's also an additional shift put on the setpoint based on the loop seal being present on Unit 2.

The actual total impact of these changes represents about a 200 pound increase above what they would normally lift if we didn't include all these conservatism.

Next slide.

This just gives you a very rough estimate of the timing of the event. Essentially there's a delay between the initial event and when the actual trip begins of .5 seconds, which is very conservative and then there's an additional two seconds before the rods drop. And when the safety valves open is when we get peak pressure, and that occurs at 8 seconds.

And this plot basically just shows you the pressure transient. Again, we're seeing from the initial condition up to the peak it's about a 500 pound increase in pressure. And again, at 8 seconds when the valve opened, the pressure drops.

DR. BANERJEE: What code was used, just for my own?

MR. FREDERICK: LOFTRAN.

MEMBER WALLIS: Extraordinary accurate code, as you can see.

DR. BANERJEE: Huh?

MEMBER WALLIS: Extraordinary accurate code.

DR. BANERJEE: Right. Right. A significant figure.

MR. FREDERICK: This slide shows you the pre-EPU results. For Unit 1 that's a good comparison because the same safety valve tolerance was used for both cases, the 3 percent. So you see about a 15 pound increase in the peak pressure associated with EPU.

On Unit 2 we actually lowered the tolerance so actually you see the numbers dropping there a pound or so.

If we do a more realistic analysis, and we have, which credits control systems, we actually see a peak pressure much lower of about 2340 absolute. And at that pressure we don't actually even lift any of the safety valves on either side, primary or secondary, or the pore for that matter.

If you go to the backup slide, and this is a plot of that particular analysis both for pre-EPU and EPU. And essentially they look identical. There was no real impact of EPU in terms of the peak pressure that we see in this analysis.

DR. BANERJEE: Well, why is that? What's the physics?

MR. FREDERICK: Essentially the control systems --

DR. BANERJEE: Safety valves are the same, right?

MR. FREDERICK: Yes. And you're not even opening safety valves here. So it's just a matter of the control system acting the same and giving you the same response out of the system.

DR. BANERJEE: But what does the control system do here?

MR. FREDERICK: The control system opens up the turbine bypass, the condenser steam dump system. And that keeps the primary system from heating much, I mean as much as you would normally see. And also --

DR. BANERJEE: Does it open the bypass earlier or something just to shave the peak off? What is happening? I'm trying to understand why the two are so close to each other in spite of the fact that you have 10 percent more power?

MR. FREDERICK: Right.

DR. BANERJEE: So what's the physics?

MR. FREDERICK: Yes. Well, the power doesn't really enter into it much at this point. Yes, it does cause a general heat up and so --

DR. BANERJEE: And that causes --

MEMBER SIEBER: That's small.

DR. BANERJEE: -- total pressure to peak?

MR. FREDERICK: Well, after the reactor trip and then once the valves open, then it turns around all these --

DR. BANERJEE: Do the valves open earlier in the --

MR. SENA: Again, this is Pete Sena, Director of Engineering.

I think the difference between the two analysis is that the original analysis takes no credit for any control systems so the steam dump systems do not operate at all. And in the realistic analysis we've done here we are taking credit for the operation of those systems.

DR. BANERJEE: So the pre-EPU doesn't take credit for the --

MR. FREDERICK: Pete, he's asking --

DR. BANERJEE: All right. There has to be a good reason?

MR. SENA: Well, the pre-EPU and the post-EPU analysis use the same --

DR. BANERJEE: It's done differently?

MR. SENA: No, no. They use the same modeling. Why don't you go back, Ken, for the pre and post-EPU

DR. BANERJEE: Then the question is why does it?

MEMBER WALLIS: I think because it's controlled.

CHAIRMAN DENNING: It's controlled.

MEMBER WALLIS: It's because it's controlled. It's the same.

DR. BANERJEE: Something opens earlier, right?

CHAIRMAN DENNING: Or bigger or more.

DR. BANERJEE: Controlled means they have to control the flow on a valve or something.

MEMBER WALLIS: It might open more, the control.

MEMBER SIEBER: It doesn't open more. I think --

DR. BANERJEE: It might open earlier.

MEMBER SIEBER: -- the differences between these two curves are so subtle that you really can't pick them out.

MR. FREDERICK: Yes, I would say that they are not exactly the same, but on here they look pretty close.

MEMBER WALLIS: Because they look exactly the same.

MR. FREDERICK: And, again, we haven't changed the control system so we'd expect it to operate.

DR. BANERJEE: Right. So what are the control events here? Like what's happening?

MR. FREDERICK: You have the loss of load times zero.

DR. BANERJEE: Right. And then there's some trip?

MR. FREDERICK: And the reactor trips, in this case on turbine trip but there's a 2 second delay model.

DR. BANERJEE: But both of them trip at the same time?

MEMBER SIEBER: No.

DR. BANERJEE: Why not?

MR. FREDERICK: Well, the condenser steam dumps this and responds to the trip signal. And also it's based off of a delta T. Essential it looks at T_{avg} and where T_{avg} should be post-trip, T_{ref} we call it. And that delta drives the valve. So that program in the system isn't changing, so it's essentially maintaining the RCS conditions in a very similar manner so you see a very similar result here.

MEMBER SIEBER: But the heat up is slightly faster so the system operates slightly quicker?

MR. FREDERICK: Yes. I mean it's a proportional --

MEMBER SIEBER: I mean you could pick it out here.

MR. FREDERICK: -- band. So if the system demands more, the values will open faster and more.

DR. BANERJEE: I know what you're saying probably makes some sense, but what I'm really trying to understand is when you show the curve, like this curve here, this curve is the result of a very complex set of -- relatively complex set of control actions.

Now between the pre-EPU and the post --

MR. FREDERICK: That curve does not actually use any of the control systems.

DR. BANERJEE: Okay. Take one which does. Let's say --

MR. FREDERICK: This one does.

DR. BANERJEE: Yes, this one. So that there are several control actions taking place. And the fact that the two curves look so similar is because there could be subtle differences. But the fact they look so similar is due to control actions taking place at different times in the two.

MEMBER SIEBER: Slightly different times.

MR. FREDERICK: The valves could be opening faster because that's what they're programmed to do.

DR. BANERJEE: Yes.

MR. FREDERICK: They look at an error signal.

DR. BANERJEE: Well, whatever it is.

MR. FREDERICK: And if the error signal is higher, than the values will open faster and further.

MEMBER SIEBER: And once they're open, they're the same in the pattern.

DR. BANERJEE: Ten percent more power is produced in the other, right?

MR. FREDERICK: That's correct.

DR. BANERJEE: So it has to go somewhere?

MR. FREDERICK: That's correct.

MR. FREDERICK: So something must open faster?

MEMBER SIEBER: Yes.

DR. BANERJEE: There's no other way.

MR. FREDERICK: Yes.

DR. BANERJEE: Right. Okay. So that's, I guess, what doesn't come out clear.

MEMBER WALLIS: That's what turns things around?

DR. BANERJEE: Yes. So what doesn't come across is what are the actions which are turning things around here? What's happening? So in one case things are happening faster; that's why it's happening.

MR. FREDERICK: Yes. The actions that are occurring, again, the control system is trying to drive T_{avg} down to the no load value, post-trip.

DR. BANERJEE: Right.

MR. FREDERICK: And the system responds based on the delta. You know, where T_{avg} is versus where I want it to be. So if in the case of EPU that delta is higher initially, then the valves will open faster and further so that you would see the same type of response --

MEMBER WALLIS: The system is actually programmed to produce a curve like this?

MR. FREDERICK: That's correct.

MEMBER WALLIS: By control.

MR. FREDERICK: Yes.

MEMBER WALLIS: That's why the two curves are the same.

MR. FREDERICK: Yes.

DR. BANERJEE: So what would be sort of valuable to know is how much more rapidly do these control actions have to occur in the second case. The curves look the same but the control actions are occurring faster or something is happening, otherwise they wouldn't.

MR. FREDERICK: Right. Yes. I'd say it's a very small difference. This whole peak occurs within 8 second.

DR. BANERJEE: One second makes a difference, right, and 8 seconds --

MEMBER SIEBER: Yes, but it's 50 seconds just for that first --

MEMBER WALLIS: Depressurization.

MEMBER SIEBER: -- pressure peak and drop. So that's a long time compared to the response time of the control system itself, which is on the order of 6 to 10 seconds.

CHAIRMAN DENNING: Is pressurizer spray having any impact here as well? I mean we've focused on kind of the relief, but is it -- I know that you don't credit it in the other analysis, but is that one of the control functions that's impacting the similarities here?

MR. FREDERICK: I'm not sure. Chris, can you answer that

CHAIRMAN DENNING: Okay. I think we can on.

MR. FREDERICK: Okay.

MEMBER SIEBER: I think the big thing is a lot of heat removal through the turbine bypass valves.

DR. BANERJEE: Right.

MEMBER SIEBER: That's the big --

DR. BANERJEE: That has to open a bit faster?

MEMBER SIEBER: Yes. Maybe a couple of seconds.

DR. BANERJEE: Yes. I wanted to know how much.

MEMBER SIEBER: Yes.

DR. BANERJEE: In 8 seconds? Is it 6 seconds versus 8 seconds?

MEMBER SIEBER: It's hard to pick off that graph.

DR. BANERJEE: Right.

MEMBER MAYNARD: Well, the rate is going to depend on how much a discrepancy between --

MEMBER SIEBER: How big the delta is, yes.

MR. FREDERICK: Actually, just a couple of weeks ago we had a loss of load event on Unit 2. And we captured some of the data from that, the pressure data.

MEMBER WALLIS: You arranged it to happen?

CHAIRMAN DENNING: Yes, you didn't do this just for us?

MR. FREDERICK: No.

DR. BANERJEE: What's that slide number?

MR. FREDERICK: It's a backup slide. It's not in your book.

DR. BANERJEE: This is one we must have,

right?

MR. FREDERICK: I'll get that for you.

MEMBER SIEBER: Ralph says he has it.

MR. FREDERICK: You see here again the LOFTRAN prediction with the control cases. Generally overall the modeling responds pretty well to the actual event, the difference here being the initial spike. And that's primarily because of the LOFTRAN analysis assumes a 2 second delay from the time the turbine trips until the reactor trips. And that's what's making that. So in reality when we had this event, we didn't see any pressure increase at all.

Just to give you an overall flavor, you know, our safety analysis says that pressure is going to go up 500 pounds. This is an actual event.

MEMBER WALLIS: The LOFTRAN can be off by what? Quite a bit.

MEMBER SIEBER: Fifty pounds.

MEMBER WALLIS: Seventy pounds or something?

MEMBER SIEBER: Fifty pounds.

MR. FREDERICK: We modeled the event exactly as it happened. We were confident that we would get very similar results.

DR. BANERJEE: No, no. But it's much

better you did it this way, really. Because if it agreed too well, then we'd just think you tuned it.

MR. FREDERICK: That ends my discussion on loss of load. We're going to move on and talk about rod withdrawal power unless there's any other questions.

Again, the rod withdrawal power is the limiting event in terms of the DNBR. And this event can be initiated by either a malfunction in the rod control system or an operator error.

As you can see, there's numerous reactor protection trips.

MEMBER WALLIS: So how many rods are withdrawn? How many rods are involved in this?

MR. FREDERICK: Is it one bank, Chris?

MEMBER WALLIS: One bank?

MR. McHUGH: We don't do it that way. We do it by inserting reactivity into the core and we do a range of reactivity insertion --

MEMBER WALLIS: Okay.

MR. McHUGH: -- from 110 pcm per second all the way down to nearly nothing. We don't explicitly model a certain number of rods. We model it in terms of reactivity.

MR. FREDERICK: But that bounds

essentially one bank at maximum speed.

MR. McHUGH: Yes.

MEMBER WALLIS: Well, I'm just trying to figure out what kind of operator error could produce this. Is he limited to withdrawing one bank and so on.

MEMBER SIEBER: Well, you're normally set to withdraw or insert a bank at a time. But if there's a malfunction or an error, it's probably going to be one bank

MEMBER WALLIS: But an operator who had some malfunction in his head, presumably withdraw a lot of rods.

MEMBER SIEBER: I don't think he can do that.

MEMBER WALLIS: He can't do that?

MEMBER SIEBER: He can pick out what bank. You can circle all the rods.

MR. SENA: Again, this is Pete Sena.

For operator action, only one rod bank can be withdrawn at a time unless you're in the overlap region where two banks can be moving simultaneously.

MEMBER WALLIS: So you bounded what's possible?

MR. SENA: That's correct.

MEMBER WALLIS: Yes.

MR. FREDERICK: Some of these trip functions also generate rod withdrawal blocks in the system, but those are not credited as part of this analysis.

As Chris mentioned, we do a range of reactivity insertion rates and we also analyze this at three distinct power levels, as shown there. In total, there's about 90 cases that are run.

Again, this is a very conservative analysis. Initial conditions are biased, again to give us the worst case results in terms of DNBR.

MEMBER WALLIS: Now CHernobyl happened 20 years ago tomorrow. And I guess what they did was they put a lot of reactivity into their reactor. A tremendous amount.

CHAIRMAN DENNING: But not by rod withdrawal.

MEMBER WALLIS: Not by rod withdrawal?

CHAIRMAN DENNING: No. No. They did it --

MEMBER KRESS: They did it by moderator.

CHAIRMAN DENNING: Moderator.

MEMBER KRESS: Negative coefficient. Not moderator. Coolant.

MEMBER MAYNARD: Starting from a very low power.

MEMBER KRESS: Yes, it was extremely low.

MR. FREDERICK: Again, the conservative values for trip functions as well as initial conditions and reactivity feedback reviews. The highest worth rod is actually assumed to be stuck out of the core.

One thing to note is that at Beaver Valley we have actually eliminated the capability to pull rods in the automatic mod. So when our rod control system is in automatic, the rods cannot be withdrawn. So it just eliminates some potential for this event to happen.

Slide, please.

Difficult to see here, I guess, but the curve here basically shows you a plot of what the DNBR result is versus the range of reactivity insertion rates that we've analyzed for both minimum and maximum feedback. Essentially you see the limiting case here, the 1.57 result. We're actually at a very low reactivity insertion rate. Essentially the lower rates cause the system to respond slower so you tend to get a worse result in that case.

The table shows the pre-EPU and the EPU result. Essentially there was very insignificant change in the result. Primarily that is due to the fact that we've changed the correlation from the old correlation to the WRB-2M in which we gained some of the margin. Again, that's associated with the real effect of the RFA fuel and the intermediate flow mixers. So essentially we gained a margin back that the power uprate would have used here for this event by changing the fuel pipe.

And again, I just want to mention that the 1.55 limit that's applied to this event and the other ones, we also have 20 percent of margin in that limit. So it's a conservative analysis and we have margin.

CHAIRMAN DENNING: Not to imply you have the old fuel in there, but you've said before it's something like a 20 percent effect on DNBR, the mixing that's occurring there?

MR. FREDERICK: Yes.

CHAIRMAN DENNING: So that if you had done the power uprate with old fuel, you would have had something like 1.37 or is that over estimating what the impact would be? Okay. Suppose you had done power uprated but you had old fuel in there --

MR. FREDERICK: Right.

CHAIRMAN DENNING: -- would you have gotten about a 1.37 here? Is that your assumption?

MR. FREDERICK: Chris, can we predict that?

MR. McHUGH: I can look that up. I think we actually made those runs. Because we had planned to do the power uprate before we had a complete transition to RFA fuel. I believe I have that on my laptop.

CHAIRMAN DENNING: Okay.

MR. McHUGH: We were going to limit peaking factors on the burnt fuel, and so it wouldn't have been a direct --

CHAIRMAN DENNING: There would have been other things that could have done --

MR. McHUGH: Right.

CHAIRMAN DENNING: -- that it would have reduced the --

MR. McHUGH: Correct.

DR. BANERJEE: Is it 20 percent difference, the new fuel in rough terms?

MR. McHUGH: Twenty percent margin was what they gained by adding the IFM grids to the RFA fuel. So, yes, it was about a 20, 21 percent increase in DNB margin from the old fuel to the new.

DR. BANERJEE: Magic.

CHAIRMAN DENNING: Magic.

MR. BURGER: Yes. If we were to have the old B5H design in there, the peaking, like Chris said, would have been a lower limit that we do have, because you don't have those IFMs and so they would have been the limiting assembly in the core.

MEMBER WALLIS: And all good engineering seems like magic to the layman.

DR. BANERJEE: I think Jeff Hewitt might disagree on this one.

MR. FREDERICK: Okay. The next event that we're going to talk about in some detail is the spurious SI or invertent DCCS. Again, this is another condition II event, which is initiated by either a malfunction in the system which trips the SI signal or perhaps some error in doing some testing of the systems.

The SI or the safety injection signal will generate a reactor trip and a subsequent turbine trip. DNBR for this event really isn't challenged because you're adding cold borated water into the system.

The primary concern here is filling the pressurizer, which again can enlist the valves and actually water through the safety valves.

Again, this is a very conservative analysis and we have actually done better estimate type analyses which show we do not overfill. But in the conservative safety analysis we do fill the pressurizer and lift the safeties.

Now the conservatism that go into this analysis, again, are primarily in the initial pressurizer level again assumed to be setpoint plus uncertainty at a high condition and also at the high T_{avg} condition, which raises the level again.

The initial conditions in temperature and flow are all biased for the worse results.

We actually run this with and without pressurizer heaters, which is a control system but it ends up effecting the temperature of the water, which is one of the inputs into the valve operability analysis. Colder water generally is worse for the valves than hotter water.

Again, two high head pumps start, and that's essentially what fills the system. For this analysis the PORVs which normally would open and prevent the safety valves from opening for this, they're not credited essentially because they are a control system.

One assumption that we also make in here is that when cool water enters the pressurizer as it's filling up, that water is assumed to mix instantaneously with the bulk fluid where you would expect some stratification normally. That, again, minimizes the temperature in the pressurizer and that's an input into the value operability analysis and it makes it more conservative.

Essentially this event ends when the operator takes action to either open the PORVs or shutdown and reset the SI signal and turn off the pumps.

If you look at the next slide, the assumption made here is that occurs at 10 minutes. And we've done simulator studies to assure ourselves that we can meet that limits.

MEMBER WALLIS: Isn't he watching his pressurizer level all this time?

MR. FREDERICK: George, do you want to speak to that?

MR. STORLIS: Yes. I'm George Storlis. I represent Operations and my background has been years of controlling Operations.

The pressurizer level is a key parameter that's monitored and it's the duty of the licensed operator at all times. And managing that level in the crises of an inadvertent SI is of utmost importance.

The automatic features systems prevent the manual shutdown for a period of time at the onset. But the parameters are monitored. The procedures are detailed, emergency operating procedures are followed and the termination of the flow rates when determined not required are of immediate importance.

CHAIRMAN DENNING: What's your backup slide here? Everything you took there, I get curious.

MEMBER WALLIS: Curious about it, huh?

MEMBER SIEBER: Sure do.

MR. FREDERICK: This is just plots from the analysis results. We see here that a pressurizer goes to its maximum level in about 7 minutes.

Next slide.

This shows the pressure as the safety valve cycle opened and closed. In cycling, the number of cycles is another important parameter that we need for our valve analysis. And for this case you can see we have five cycles of the valve before the operator mitigates the event.

MEMBER SIEBER: And that's in a 100 seconds, roughly, 150 seconds?

MR. FREDERICK: That's correct. Yes.

DR. BANERJEE: Do you get any two phase flow through these valves or is it just blowing steam?

MR. FREDERICK: Well, in this case the

pressurizer is full, so --

DR. BANERJEE: So you get water?

MR. FREDERICK: -- a water discharge.

MEMBER WALLIS: But doesn't it flash when it gets --

DR. BANERJEE: Yes.

MEMBER SIEBER: Yes, it does.

MR. FREDERICK: Yes. It flashes in the discharge --

MEMBER WALLIS: Now there's indication of temperature in the discharge line, isn't there, in the control room? Probably rings a bell or something. When there's a temperature in the discharge line from the pressurizer it's measured, isn't it?

MR. FREDERICK: Yes. There is a tailpipe alarm, yes.

MEMBER WALLIS: He's told. As soon as this thing happens, he's told if he doesn't know already.

MR. FREDERICK: Yes.

MEMBER SIEBER: You can assume that the water in the pressurizer is saturated.

DR. BANERJEE: In which case it will get critical fast.

MEMBER WALLIS: Critical flaw at pressure.

Right.

DR. BANERJEE: So do you use a critical flow calculation at that point once it comes out?

MR. FREDERICK: Chris, the safety valve flow model, is that --

MR. McHUGH: I believe it's critical flow -- the first cycle usually starts out with a little bit of steam and then the pressurizer rapidly fills once it opens and the remainder of the cycle is water. And then the remaining cycles are typically all water. The first one does start with steam typically.

MR. FREDERICK: This slide just shows how the pressurizer water temperature drops as your discharging water out of and it's insurging. And again, it's assumed to instantly homogenize and reach a bulk temperature.

DR. BANERJEE: Do you have a graph of the discharge rate? I mean, how the discharge varies? You showed a slide previously, I think that was --

MEMBER WALLIS: It seems to depressurize very rapidly on that slide.

DR. BANERJEE: Yes.

MEMBER WALLIS: There seems to be plenty of flow there.

MR. FREDERICK: The mass flow rate out of the valve, is that what you're asking?

MEMBER WALLIS: Yes.

DR. BANERJEE: It must be very high.

MR. FREDERICK: Yes, it is.

MR. McHUGH: I think I have that information on my laptop.

MEMBER SIEBER: So you're solid, there's no cushioning effect from any steam in there. So the pressure is going to go up very rapidly.

DR. BANERJEE: Can I see the previous slide, please?

MEMBER WALLIS: See how rapidly it comes down?

MEMBER SIEBER: Again, because you're solid.

DR. BANERJEE: Yes. You don't have to do it now, but if you've got it on your laptop, nice to see it.

MR. FREDERICK: Chris, it's in the RAI responses that we submitted, so --

DR. BANERJEE: Is it?

MR. FREDERICK: Yes.

DR. BANERJEE: The 3,000 pages or something, no?

MR. FREDERICK: So, again, yes this

analysis does generate overfill of the pressurizer and as such, the results are essentially used as inputs to an evaluation that we do to determine whether or not the safety valves are going to function under the conditions that we're presenting to them.

The valve evaluation uses WCAP 11677 methodology. And that's primarily based on results from the EPRI valve testing that was done post-TMI where they actually put water through the valves at various conditions and temperatures.

The PORVs are also qualified. We looked at those in terms of water discharge as well as the discharge piping on both the PORVs and the safety valves. We've analyzed all the lines for these conditions and shown that we met the limits.

MEMBER WALLIS: Because you can get choking in the discharge line. Can get critical flow in the discharge line because the depressurization is tremendous.

MR. FREDERICK: Yes. Was it a RELAP analysis to generate the forcing functions on that, Mike?>

DR. BANERJEE: Yes, you can get multiple choking in lines like this, but RELAP wouldn't calculate that, I would think.

MEMBER SIEBER: Yes. There's a number of elbows in that line. I think the analysis that was done was to make sure that the line would stay intact. There's tremendous forces on that line as this slug of water goes --

MEMBER WALLIS: Well, if it chokes at the discharge into the drain tank, that's where you worry because then you get a pressurization of the whole line.

MEMBER SIEBER: Yes. Well, I would imagine almost immediately the drain tank ruptured just with--

MEMBER WALLIS: No. There is a while, isn't there, before that happens?

MEMBER SIEBER: Pardon?

MEMBER WALLIS: Isn't there quite a while before that happens?

MR. TESTA: Yes. This is Mike Testa.

We analyzed the piping from the pressurizer from the pressurizer itself and including the piping down to the PRT. And as Ken said, you know once we overfill, of course, and we're putting water down the line, we used the RELAP computer code to derive the forcing functions. And then incoded that into the piping analysis, piping model to make sure that the piping and the supports would remain intact or acceptable.

MEMBER WALLIS: You don't challenge the rupture disk of the drain tank?

MR. TESTA: No, I don't believe we did.

MEMBER SIEBER: To what, 50 pounds?

CHAIRMAN DENNING: We're running behind, but that's okay. We're going to let this go.

MEMBER WALLIS: You mean we may be a little late tonight?

CHAIRMAN DENNING: Exactly.

MR. FREDERICK: I just have one more area before --

CHAIRMAN DENNING: That's okay.

MEMBER WALLIS: Are you going to do large break LOCA before you --

MR. FREDERICK: Yes.

CHAIRMAN DENNING: Yes.

MR. FREDERICK: One other issue which the Staff raised on the concern here was if the PORVs opened, they wanted us to demonstrate that we had a qualified signal for them to close, even though the PORVs are considered a control grade. However, they do have a signal which comes out of the protection grid systems which close the valves on a low pressure signal from the pressurizer. So the concern here was if you needed to rely on block valves which would be available then that was more of a condition III, that we were able to demonstrate that we do have a qualified signal to close the values.

So summary on the spurious SI, we have analyzed the valves for the water discharge condition was identified and we're convinced the valves can pass water without damage. Likewise, for the PORVs and the PORVs do have the qualified signal to close. And this event will not promulgate a condition III event.

MR. SENA: Again, this is Pete Sena.

I just want to also reemphasize a couple of things.

Jack, you asked about the PRT, the ruptured disk goes at a 100 pounds, not 50 pounds. And additionally, we've simulator crews both units through an inadvertent SI scenario. And they are able to diagnose the event, confirm that we do not have the actual real event such as a LOCA or a tube rupture, and terminate the SI prior to going to solid conditions. And actually, in 2002 we had a real inadvertent SI on Unit 1. And based on that real plant data we also did go solid in that case.

CHAIRMAN DENNING: What was the nature of the event that occurred? How did it --

MR. SENA: What happened in 2002 at Unit 1, one of our main steam isolation valves closed due to a human performance error involving the building of scaffolding. The closure of that valve then resulted in a low steamline pressure from the other two steam generators supplying the turbine. So again, you do not have a valid steamline break, but that's what it sensed at 500 pounds low steamline pressure. So a safety injection signal was actuated and a reactor trip from full power.

CHAIRMAN DENNING: Two high pressure points?

MR. SENA: Yes, two high pressure safety injection pumps actuated, all ECCS pumps actuated. Operators were able to progress through the EOPs and terminate the SI prior to going solid.

MR. FREDERICK: Just to wrap the non-LOCA discussion here. Again, for the analyses that we've done we've shown that we meet all the DNBR limits as well as the pressure limits for primary and secondary. And all the acceptance criteria for the condition II, III and IV events are met at the EPU conditions.

Again, that's it for the non-LOCA and we'll move on to large break LOCA unless there's any questions on that.

For EPU we have, again, gone to the best estimate LOCA methodology, as we discussed before. And, again, this is the original 1996 approved methodology that Westinghouse has used for many plants.

Due to the methodology, there is some benefit in terms of the PCT result as well as changes that were made in the containment and accumulator minimum pressure, which also provides some benefit in terms of the PCT. The container pressure associated with conversion increases the initial operating pressure about 4 psi. And that increase in the back pressure transient that associated with the LOCA event does provide a benefit in terms of PCT. And primarily, this is due to a reduction in what we call downcomer boiling. The downcomer boiling tends to impede vessel refill and that is very sensitive to the containment back pressure.

Also we did primarily for small break analysis we raised the minimum accumulator pressure and that had a small benefit here as well.

So essentially some of the margin that we would lose from EPU we have regained by some of the other plant changes that we've made.

And the results, as shown on the next

slide here --

DR. BANERJEE: What is the small slide?

MR. FREDERICK: Okay. This is a general discussion about what DE methodology is. If you're interested, we can talk about it.

MEMBER WALLIS: No. They're conservative assumptions, all of these things.

MR. FREDERICK: Yes. This basically goes through what assumptions are bounding and then the balance that I talked about how the uncertainties were rolled into the final PCT value.

MEMBER WALLIS: A response surface type of thing, is it?

MR. FREDERICK: That methodology, yes, it does use the response surface.

MEMBER WALLIS: Now what surprised me here, maybe I'm ignorant of these, it looks as if you're limited by your maximum hydrogen generation. Usually the peak clad temperature that limits. And you seem to have an awful lot of oxidation in yours.

MR. FREDERICK: In the BELOCA methodology is --

MEMBER WALLIS: Is it because it stays hot for a long time or something, is that what it is?

MR. FREDERICK: Pardon me?

MEMBER WALLIS: Why are the oxidation numbers pushing the limit? Usually it's the peak clad temperature. Is it because --

MR. FREDERICK: For the hydrogen generation.

MEMBER WALLIS: -- the temperature stays high for a long time or something?

MR. FREDERICK: Right. Matt, do you want to address that in terms of the conservatism?

MEMBER WALLIS: A bit strange to me.

MR. CERRONE: Yes. This is Matt Cerrone with Westinghouse.

Well, first of all, you're right. They do have an extended reflood period so they have a higher PCT and you can see this manifests itself in the core wide oxidation number.

In the methodology, the development of that number is conservative. It's very conservative in that the transient used to generate the numbers developed based on PCTs that are beyond the 9th percentile and it has -- the transient goes for a longer period of time than the PCT transient.

So basically what you're doing is you're making sure that you have a high transient that has a high PCT and has an extended reflood period. Okay.

And then beyond that, the local uncertainty code that we use extends the reflood heat transfer longer in time. So basically it's a conservative number. And the methodology allows for additional COBRA/TRAC calculations to be performed as a measure to reduce the additional -- reduce the conservatism until ultimately you show success at the hydrogen generation, 1 percent acceptance criterion.

Three's an additional work that could be performed to show additional margin in that number.

MR. FREDERICK: Yes. I guess the answer there is we do enough to show we meet the limit and we don't push it beyond that, although there are additional margin to be gained.

MEMBER WALLIS: But the question for Westinghouse, is this an unusual plant where the CWO, the core wide oxidation seems to be the limit here? It doesn't seem to be in my memory a very common thing.

MR. CERRONE: Well, no, it's not all that common, certainly.

MEMBER WALLIS: Is there something unusual about this plant or the method of analysis, or what?

MR. CERRONE: No. It's not unusual. The evaluation techniques were in line with what was in the approved evaluation model. So I think here we're just seeing a PCT and a high oxidation, a higher oxidation number. But like I had said additional work could be performed if it was so needed to generate additional margin and the maximum hydrogen generation number.

DR. BANERJEE: Are you going to show us some curves or clad temperature with times so we get a feel for what's going on?

MR. FREDERICK: I did not include those, no for the large break. I do have some for small break.

DR. BANERJEE: So it would help, I think, in answering some of these questions to see how long the fuel clad temperature remained high or whatever and when reflood came in.

MR. FREDERICK: Matt, do we have the BELOCA WCAPS here?

MR. CERRONE: Yes, I brought Unit 1 and Unit 2 reports with me.

MR. FREDERICK: Okay. Well, the technical reports do have that information if you want to look at it.

DR. BANERJEE: Yes. We don't need all the details, but at least a few for the temperature transient. And they can show it later, maybe.

MR. CERRONE: I could check to see if am electronically, if not I have I think a reference transient with the one break would show an illustration.

MR. FREDERICK: Yes. Just make some copies of those graphs.

DR. BANERJEE: Right.

MR. FREDERICK: And then you can pass them out.

DR. BANERJEE: Of the relevant graphs.

MR. FREDERICK: Right.

CHAIRMAN DENNING: And we could do that during lunchtime and then look at them after lunch if we want to take a look at that.

MR. FREDERICK: So essentially a PCT transient --

MR. CERRONE: OF the large LOCA.

MR. FREDERICK: For the large LOCA.

CHAIRMAN DENNING: Yes. I think particularly --- yes. You'd like to see also if you can in what time period is the hydrogen being generated. Over what time period --

MEMBER WALLIS: Right. Right.

CHAIRMAN DENNING: -- is hydrogen

generation occurring.

MR. CERRONE: It'll help illustrate that. I mean, the time at the transient is above 1700 degree is when you'll be oxidizing.

MR. CARUSO: The transient, though, that you're going to show us is that necessarily the one that produces the maximum hydrogen generation?

MR. CERRONE: No.

MR. CARUSO: That's a problem. Because you probably don't have the graph that generates maximum hydrogen generation. So --

MEMBER WALLIS: It's not the same as the PCT graph.

MR. CARUSO: It's not the same as the PCT.

MR. CERRONE: For each period; blowdown, early reflood and late reflood. A PCT at the 95th percentile is developed in this methodology. In the 95 EM an additional COBRA/TRAC transient's computed where the PCT calculated goes beyond that of the 95th for each of the three periods. So what you do them is you capture the oxidation period above the 95th percentile with the COBRA/TRAC calculation. So you oxidize above the temperatures all experienced in each period at the 95th percentile an you capture the time and temperature.

MR. CARUSO: Is that the scenario you're going to present to us?

MR. CERRONE: Well, I was just thinking through that. The engineering report, I do not believe, provides the oxidation transient that was developed.

MR. CARUSO: That's what I was wondering.

MR. FREDERICK: Yes, I think it will be somewhat representative.

MR. CARUSO: Okay.

MR. FREDERICK: Kind of a general --

MR. CARUSO: Because you just have to be careful, Sanjoy. I think you're looking for the actual transient that generates that .98 percent and you're not going to see that. You're going to see something similar.

MR. CERRONE: Yes. I think what we can do is take each time period --

DR. BANERJEE: The reason, of course, is that what -- at least the way you're putting it, it's a very conservative calculation, right?

MR. CERRONE: Correct.

DR. BANERJEE: Maybe we need to have that when you show -- well, the first thing it would be nice to get the curve which produces that .98, which is relatively close to the limit, right?

The second is that the conservatism maybe should be just listed as a snapshot for us to see so that we can say okay, that .98 is really an upper limit, I mean it's very conservative or something like that. Did I come across? I mean, do you have a feel for it?

MEMBER WALLIS: Because we're discussing a power uprate and it hasn't changed tremendously from .91.

DR. BANERJEE: Right. That was pretty high already.

MEMBER WALLIS: Yes, that as pretty high already.

DR. BANERJEE: It went from a very conservative calculation of .91 to a best estimate of .98?s

MR. CERRONE: Well, we need to keep in mind that the oxidation calculation is conservative even in the original '96 evaluation model using COBRA/TRAC. And keep in mind also that additional COBRA/TRAC calculations could be performed at various power levels to capture the rod power senses throughout the core to give you more and more -- to give you additional levels of margin. The idea is that there's a regulatory limit that we must comply with. And we basically provide a sufficient amount of evidence that we've met that limit.

DR. BANERJEE: Yes. I guess when you say best estimate here, you really have markings in this best estimate.

MEMBER WALLIS: Yes. It's not totally best estimate..

DR. BANERJEE: Yes.

MEMBER WALLIS: There's a lot of conservatism on top of it.

MR. CERRONE: Yes. Especially in the oxidation calculation. We look forward to the ASTRUM, when we move to ASTRUM with this because there is oxidation margin.

DR. BANERJEE: Perhaps that could be at least clarified. Because I'm confused.

MEMBER WALLIS: Well, I think the best estimate number would be much lower if you went from the mean rather this 95th percentile in that.

MR. CERRONE: I would agree.

MEMBER SIEBER: The difficulty, though, is in regulatory space you either meet the number or you don't.

MEMBER WALLIS: That's right. That's

right.

MEMBER SIEBER: And the conservatism you have --

MEMBER WALLIS: And you do have enough to do that. Right. Right.

MR. CERRONE: There's always been plenty of ways to find margin --

MEMBER WALLIS: That's why it came out to .98 because you had to be under one.

MR. CERRONE: Sure. I mean you did a sufficient number of calculations, you show compliance.

MEMBER WALLIS: That's right. I understand.

DR. BANERJEE: Anyway, we want listing the assumptions and conservatism with that curve, then at least we have a feel for it.

CHAIRMAN DENNING: Okay. I think we can proceed.

MR. FREDERICK: Okay. Yes, we're done after this one.

The one thing I wanted to point out here was that the P-clad temperature that you see there for Unit 1 will be a different number as even the draft SER. When we did the original Unit 1 analysis the result came out to 2144. And those original analyses were based on different containment operating conditions that we had in place at the time or we're proposing for the containment conversion. When we changed those initial conditions, we went back and reanalyzed both units. And the number for Unit 1 dropped primarily because we lowered our peaking factor limits associated with Unit 1 analysis because we were seeing an unacceptable increase due to the containment pressure change. So that's the result that we will be reporting essentially is official 50.46 type results is the 21 number.

DR. BANERJEE: What is the reason for the different between Unit 1 and Unit 2?

MR. FREDERICK: In the results?

DR. BANERJEE: Yes.

MR. FREDERICK: The major difference between the plants is in the downcomer area. One unit has what they call thermal shields and the other one has the neutron blanket. And those represent, basically, fairly significant thermal masses but they are different between the plants. So Unit 2 tends to be a lot less sensitive to downcomer boiling type conditions, low pressure in containment than Unit 1.

Initially actually Unit 1 resolve was

actually much higher, was 2144 for similar input conditions. For example, the peaking factors were originally all the same. The result here is that they're not that different here, but actually Unit 1 here is restricted to a lower peaking factor limit than 2. The difference is in the plant is reflected in the analysis.

DR. BANERJEE: Raising of the containment pressure didn't take care of this downcomer boiling problem?

MR. FREDERICK: It helps, but it does not completely eliminate.

That's all I had on large break. I guess we're going to shift over to the NRC now.

CHAIRMAN DENNING: Yes. We'll at least start the Staff's presentation here and then we'll see if we want to have a breaking point in the middle of it, if that's okay.

MR. MIRANDA: Okay. The answer to your first question is we're using this overhead projector because I have some transparencies with some transient plots on there and I'd like to have the ability to draw on them.

My name is Sam --

MEMBER WALLIS: On the screen, whatever

you do.

DR. BANERJEE: Well maybe draw on the screen so we can have it changed and focused.

MEMBER SIEBER: We already tried that.

MR. MIRANDA: My name is Sam Miranda. I work at the PWR Systems Branch of NRR as a technical reviewer.

I've been with the NRC for a little more than 5 years. And before that time I worked for Westinghouse as a nuclear safety analyst for almost 25 years, during which time I used LOFTRAN code and worked with the author of LOFTRAN, Toby Burnett to write several routines in LOFTRAN.

First I will go quickly through the --

DR. BANERJEE: Where are these slides?

MEMBER SIEBER: They're in here, I think. I'm going blind.

MEMBER WALLIS: That's almost as good as the other one.

MR. MIRANDA: Okay. For the EPU at Beaver Valley there is no change in the fuel design. By the time the EPU will be implemented, the entire core will be composed of robust fuel assemblies. And there's been no change in the methodology used for the nuclear design.

As far as thermal hydraulics is concerned, since the entire core is robust fuel assemblies, there's no DNBR penalty for the fuel transition. And the THINC IV code has been replaced by the VIPRE code in the DNBR evaluations.

Both --

DR. BANERJEE: The difference between these codes?

MR. MIRANDA: The VIPRE code seems to be more flexible. You can model cores with, for example, hexagonal lattices rather than just square lattices. There are features in VIPRE that allow it to do things that THINC has problems doing.

DR. BANERJEE: Are these subchannel codes or what?

MR. MIRANDA: They're detailed core models where you can have a hot channel an you can have surrounding fuel assemblies and you can also model the fuel itself, the pellet, the gap and the clad, calculate temperatures and stresses and heat flux.

Both the revised thermal design procedure and the standard design procedures were used in the analyses depending upon the limits of these methods and the requirements of the accident analyses themselves, as discussed earlier by Mr. Frederick.

This is a review of the large break LOCA analyses and as compared to the 10 CRF 50.46 limits.

CHAIRMAN DENNING: And you're showing the older version of the peak clad temperature for Beaver Valley 1?

MR. MIRANDA: The older version?

CHAIRMAN DENNING: That's not 2144 anymore.

MEMBER SIEBER: Yes, that's one cycle before the cycle --

MR. MIRANDA: Revised.

MR. FREDERICK: Ken Frederick.

That is the value that we had on our original analysis before we reanalyzed.

MR. MIRANDA: Yes. We didn't incorporate the new number in this slide, but yes the licensee has submitted a new number.

MEMBER WALLIS: This is something that we don't have, this slide, is that right?

DR. BANERJEE: Do we have this slide?

MR. MIRANDA: No, you don't have this slide. This was added at the last minute.

CHAIRMAN DENNING: So you'll get us a copy of this. Okay. But there's nothing new on there?

MR. MIRANDA: No.

CHAIRMAN DENNING: Stick it up just another second. That's basically just supposed to show us what the applicant calculated.

MR. MIRANDA: Right.

CHAIRMAN DENNING: Right. And we've already seen that.

MR. MIRANDA: And to show you that the limited have been met, yes.

CHAIRMAN DENNING: Okay. Good. Thanks.

MR. MIRANDA: I'm going to get into a discussion here about the margins and acceptance criteria and then which will lead into a discussion of the results for three examples of transient analyses. And this is going to be very basic.

We have on the left hand column the ANSI criterion that defines conditions I, II, III and IV events and the acceptance criteria and how we get from there to the analysis criteria.

The ANSI standard from 1973 defines anticipated transients condition II events, otherwise known as anticipated operational occurrences. As events that could occur during the calendar year of operation at a plant. And it's defined basically as an event that basically requires no more than a reactor trip. Plant trips you correct a condition and you're back to power in short order.

There are basically three analysis criteria that apply to condition II events. One is that the RCS does not overpressurize and also the main steam system does not overpressurize. Another is that you have no fuel clad damage, and this demonstrated by showing that you meet the DNBR safety analysis limit. And finally, that the condition II event does not develop into a more serious event. And this criterion is designed to prevent a shortcut or short circuit in the sense that you can't have a condition III or IV event that originates as a condition II event with a condition II frequency of occurrence. Because a condition III or IV event has other acceptance criteria.

And as far as analyses are concerned, this last condition that the event does not promulgate into a more serious event is shown by demonstrating through analyses that the pressurizer doesn't fill. And this is done to preclude the possibility of passing water through any of the pressurizer relief or safety valves which may not be qualified for water relief. And in deterministic accident analysis if a valve is not qualified for water relief, it's assumed to stick upon. And a stuck open valve then constitutes a small break LOCA in the steam space of the pressurizer.

Another option to satisfy this criterion is to qualify the valves in question, either the pullers or the safeties or both. And in this case Beaver Valley is qualified to safety valves.

Condition III events which may occur during the lifetime of the plant, there is some allowance for fuel clad damage. And these are governed mainly by the dose consequences which have to meet the 10 CRF 20 release limits. But in many cases in accident analyses this is satisfied merely by meeting the more stringent condition II criteria.

As far as condition IV events are concerned, the limiting faults also dose criteria apply, 10 CFR Part 100. And, again, a lot of the accident analyses, steamline break is one example, where this is satisfied by meeting the condition II criteria.

There's also 10 CFR 50.46 with the PCT limits and so on. And that's all aimed at the ANSI standard from 1973 which talks about maintaining the ability of protection systems that are needed to mitigate the event. And that goes to the -- of the core and maintaining core geometry.

In accident analyses found in Chapter 15 the non-LOCA events, this is often shown by showing that there's no boiling in the RCS system and no hot leg saturation. And this happens to be a Westinghouse internal criterion. By showing that there's no boiling in the RCS, you can show that the core will not uncover and the event ends there. The evaluation need not continue to more complicated factors. It also happens, it's very convenient for Westinghouse since LOFTRAN is not capable of modeling a two phased flow. So when you reach a hot leg saturation you should be done with that analysis.

There's another category here they added, ATWS. ATWS is not covered by this ANSI standard. ATWS was invented in 1969 by an ACRS consultant named Dr. Epler. And the Staff issued guidelines for analysis of that ATWS and acceptance criteria in WASH-1270. And ATWS was the first category that was to be analyzed according to a probabilistic safety goal of no core damage. I believe it was something like 10 to the minus 5, then it went to 10 to the minus 7, then it went back to 10 to the minus 6. But the various vendors submitted analyses in 1974 to show the consequences of ATWS. And this issue continued until the promulgation of the ATWS rule in 1986, 10 CFR 50.62 which actually does not require analyses. It just requires the installation of certain hardware.

For PWRs this is a diverse SCRAM system and an ATWS mitigation systems actuation circuitry. And for Westinghouse plants it's just the AMSAC system, because Westinghouse demonstrated that DSS was not justified.

ATWS analyses are conducted on a best estimate basis. And the principal criterion there is RCS overpressurization. And the level C stress limit was chosen as the acceptance criteria, 3200 psig. And this is based on review of the various components of the RCS system and picking the weakest component. In many cases that is the reactor coolant pump cases.

And another item that's important in this level C stress limit is the valve disks for valves that are needed to proceed to safe shutdown. The pressure has to be kept to a level such that there would be no deformation of the valve disks so that they remain operable and the plant can proceed to safe shutdown after a ATWS.

This is similar to what you've seen before. This example, which is based on the WRB-2M correlation shows that the correlation limit, the 95 percentile ability, the 95 percent confidence level is 1.14. And this includes uncertainties that are encountered during the development of the correlation.

And then the design limit 1.22 includes the operational uncertainties on power level, temperatures and flow rate mainly.

And then to this is added some margin. For Beaver Valley's case it's about 21 percent. And this margin would include, for example, transition core DNBR penalty, would include rod bow. In this case, the transition core, the DNBR penalty doesn't apply.

For the reactor coolant pressure boundary, I've chosen the level C stress limit, I'll call that the best estimate since it's used for ATWS analyses. And then the safety analysis limit is the 110 percent of design pressure, which leaves us a margin of about 17 percent.

CHAIRMAN DENNING: One second. On the 1.55, Staff has accepted lower values than 1.55 for these kinds of transients, is that true on a CHF?

MR. MIRANDA: Yes. Yes. That's true.

CHAIRMAN DENNING: This is a reasonably conservative value from your interpretation?

MR. MIRANDA: Yes. Yes, it's reasonable. I've actually compared to other plants, this has more margin.

CHAIRMAN DENNING: Thank you.

MR. MIRANDA: Now I'm going to talk a little bit about margins and where they're found. And in the first grouping is in the acceptance criteria themselves. And from a prior slide we saw that the analysis criteria are more stringent, there's more margin in there in order to show that the standard acceptance criteria met. The standard acceptance criteria sometimes can be a little bit hard to measure, but the analysis criteria have to be measurable.

So in the acceptance criteria themselves, some events are analyzed according to more stringent criteria. For example, the steamline break, a condition IV event, or the complete loss of flow, a condition III event, are both analyzed according to condition II acceptance criteria meaning no clad damage.

Then there's also some margin between the acceptance criteria and the standard in terms of shortcuts like the pressurizer no fill criterion. And also as far as the fraction failed fuel rods. And the condition III and IV event, for condition IV events for example, the fraction of failed fuel rods is largely determined by the dose consequences. And the fraction of failed fuel rods some value is chosen that is known to produce acceptable dose consequences. In a prime reading for Ginna, for example, there was a statement in the Ginna SE which talked about the assumed level of failed fuel rods. This refers to the practice of doing an analysis, doing a rod census and calculating the number of rod failure. And if it meets some predetermined level, for example, 10 percent, then it's acceptable. Very often that number is much less than that, maybe 2 or 3 percent. The 10 percent value would be used by the dose people as standard practice. Get the dose consequences for a 10 percent level of fuel rod failures when the analysis actually shows something much less.

In the initial conditions and parameter values, the initial conditions for the accident analysis are taken in the conservative direction. Power level, for example, would be at 102 percent power. RCS temperatures depending upon the accident analysis and what they are looking for, very often the RCS temperature would be about 4 degrees higher than nominal. There's also some level of steam generator tube plugging that's assumed as well as pressurizer and steam generator water levels.

The protection system setpoints are also taken in the conservative direction.

MEMBER WALLIS: This is what's done by this plant. It's not always done, is it?

MR. MIRANDA: It's always done, yes.

MEMBER WALLIS: Always done?

MR. MIRANDA: Always done.

MEMBER WALLIS: Even in a best estimate with uncertainty, you still have these conservatism?

MR. MIRANDA: Well, these are not best estimate analyses. These are conservative analyses.

MEMBER WALLIS: Conservative?

MR. MIRANDA: Yes.

In practice, taking all of these uncertainties in the conservative direction could actually wind up with a plant in a configuration that's not possible physically, but they do it anyway. You might, for example, take the under block values for core reactivity and beginning of life values for temperatures.

Core reactivity feedback, for example. They might take a most negative moderator temperature coefficient which would occur at end of life, it might be much more negative than actually expected. And then at beginning of life you would have a zero coefficient or positive coefficient. The object there is not only conservatism, but also to produce a very wide range of analyzed space so that in the future for core reloads of different core designs with different core moderator temperature coefficients and other coefficients, doppler for example, if those values for the characteristic of the core reload fall within this range, that would tend to eliminate the need for new analyses.

And Westinghouse calls this their reload safety evaluation checklist.

There's also margin added to key parameter values used in the accident's analyses. Rod drop time, for example, was typically 2.8 seconds. The actual value is closer to 1½ seconds. Safety injection flow if it's conservative to have a minimum flow of, then the pump, the performance codes are taken at a minimum value.

Decay heat generation is another example. Decay heat generation --

MEMBER WALLIS: Is this stuff in a Reg. Guide somewhere or is it actually in the rule, or is it just the way it's done?

MR. MIRANDA: This is the practice. Yes.

MEMBER WALLIS: This is precedent. It's not rule?

MR. MIRANDA: No. It's experience.

MEMBER WALLIS: This is the way it's normally done?

MR. MIRANDA: Yes. Yes.

Decay heat generation is another one I'm sure you're familiar with. It's either 1971 model plus 20 percent or a 1979 model plus 2 sigma.

And Scram worth, typically for a Westinghouse plant that might be 4 percent. The actual value is closer to 6 percent because they assume that the most reactive rod is stuck out of the core.

Just in response times. The same thing. Typically rods don't get begin to drop until maybe 2 seconds after the signal was received. And that actual value is closer to 1 second or .8 seconds

Also response times in terms of pump startup times to reach full speed or opening valves. For example in the safety injection system before flow delivery could occur to the RCS, it might be 10 seconds. It's actually less than that, especially if you consider for example the relationship between flow area and valve position.

MEMBER WALLIS: All of this sounds qualitatively good. But until you put it in a terms of a probability distribution or something, I don't really know what you're gaining. I mean you say we're going to assume 2 seconds when reality is more like 1. But presumably it's one with some uncertainty.

MR. MIRANDA: Yes.

MEMBER WALLIS: Your two is somewhere way beyond the uncertainty bound or it's sort of 99.9999 percentile or something, or what is it? It sounds good, but I don't have an idea.

MEMBER SIEBER: You do rod drop tests and I think two is the ultimate limit, but most of the time a rod will drop around 1 second or 1.2 seconds.

MEMBER WALLIS: That's a qualitative statement.

It all sounds good, but I just wonder why it isn't all put into some soundness, sort of probabilitistic basis and then we can do a bounding best estimate with uncertainty.

MR. MIRANDA: This method predates PRA.

MEMBER WALLIS: Yes, it does. It seems to be a bit archaic. That's why you're using this particular projector, isn't it?

MR. MIRANDA: It's consistent, yes.

MEMBER SIEBER: It's structural.

DR. BANERJEE: But it actually focuses better.

MEMBER WALLIS: The focus is much better, right.

MEMBER SIEBER: Structuralist.

MEMBER WALLIS: It's cheaper to do it this way?

DR. BANERJEE: Sounds like these are sort of limiting values that you use?

MEMBER SIEBER: Yes.

MEMBER WALLIS: They are.

DR. BANERJEE: One end of the probability distribution?

MR. MIRANDA: That's right. It is possible sometimes to do sensitivity studies where you isolate some of these things and you might do the same analysis, for example, with a 2.8 second drop time and a 1 second drop time and see what effect it has on your parameter of interest. And you can do this for hundreds and hundreds of cases and come up with some kind of a relationship. But it hasn't been necessary as long as you show that the safety analysis limit is met, there's no point in going any further.

DR. BANERJEE: And maybe you don't know the probability distributions anyway, you know.

MEMBER MAYNARD: Right.

MR. CARUSO: That costs money to determine that.

MR. MIRANDA: Well, okay.

MEMBER SIEBER: Well, from a legal standpoint this method is much easier to defend; you either make it or you don't. You build a box and the reactor fits in there, it's good. If it doesn't fit in there, it's not good.

MR. CARUSO: And if you have a problem meeting your criteria at some point, then you go look at an individual factor and say, well, is it necessary for me to refine that value in order to meet the criteria. And then you have to develop the data that's needed to support the value that you use. But it's easier to use the limiting value until you need to.

MEMBER SIEBER: That's the old regulatory system. And it is still used pretty widely.

MEMBER WALLIS: It produces the same results on Monday as it does on Tuesday.

MEMBER SIEBER: That's great.

MEMBER WALLIS: Well, is an interesting --

MEMBER SIEBER: And Plant A and Plant B look the same if they are the same.

MR. MIRANDA: There' margin also in the methods used in the analyses. We heard a little bit earlier about critical flow through the pressurizer safety valves. LOFTRAN has several critical flow correlations in it and you use the appropriate model.

For example, steamline break you might want a very high flow through the break.

For a case where you're worried about RCS overpressurization and you're looking at flow through the pressurizer safety valves, you might use a flow correlation that produces a lower flow.

And it has, for example, homogeneous equilibrium subcooled and saturated models, and moody models.

Again, for steamline break make an assumption that the steam break flow is dry steam. This maximizes the cool down that the steam break produces in the core and maximizes the core reactivity response.

In actuality, a steamline break would have considerable entrainment in it. And I know this from experience because Turkey Point Unit 3 had a steamline break in 1971 when they were doing pre-startup testing. The core was not loaded at the time, but they blew a safety valve off the header on the steamline and the steam generator blew dry in a time that was much faster than predicted by the computer code. And the difference was attributed to water entrainment.

DR. BANERJEE: But I guess conservative here must be carefully defined, right? It's conservative with regard to some specific parameter that is of concern, like peak clad temperature, reactivity or whatever.

MR. MIRANDA: That's right. We'll see some examples of that in the plots.

There's also as far as --

MEMBER WALLIS: What you're describing is just what these guys did at Beaver Valley?

MR. MIRANDA: Yes.

MEMBER SIEBER: Yes.

MR. MIRANDA: Yes. This is standard Westinghouse methods.

MEMBER WALLIS: I thought Westinghouse had better methods now.

DR. BANERJEE: Well, only when they need it.

MEMBER SIEBER: The answer is no? This is the licensing approach.

MR. MIRANDA: Yes. This is methodology that the Staff has seen before, it's familiar with and has approved of.

LOFTRAN and RETRAN, but in this case we're talking about LOFTRAN has a derivative method. They call it to estimate the DNB ratio. And this is a shortcut.

Rather than go through the VIPRE analysis to actually calculate a DNB ratio, LOFTRAN has the results of sensitivity studies of the effect on DNB ratio due to changes in pressure and temperature. And during a transient, as you move through the transient and you change temperature and pressure, it calculates a DNB ratio. And this deliberately programmed into LOFTRAN to give you a lower than expected DNB ratio. And then the practice is depending upon what the DNB ratio is. For example, if you do a raw hydraulic power analysis, then you come up with a DNB ratio of 1.5 and the safety analysis limit is 1.55. You know that 1.5 of value is conservative from LOFTRAN but you can't prove it. So you take some stake points from the analysis and you put them through a VIPRE analysis and you come up with a better DNB ratio. And that's very often much higher, 1.6, 1.65, whatever. But it does eliminate a lot of VIPRE analyses to go through this estimate.

MEMBER WALLIS: I believe this is all going back to the days when it was expensive to use a computer?

MR. MIRANDA: Yes. It goes back to those days. And furthermore, not only was it expensive to use the computer, but you had to use several codes.

MEMBER WALLIS: Took a long time to run, too, I think.

MR. MIRANDA: Took a long time to run. And you had to physically take those stake points and put them into another --

MEMBER WALLIS: Take some perforated paper from one computer to another, or something.

MEMBER SIEBER: And boxes of cards.

DR. BANERJEE: Boxes of cards.

MR. MIRANDA: Yes. Yes. And a technician with a piece of graph paper.

MEMBER SIEBER: Yes.

MEMBER WALLIS: Now are we back in the '60s or something here? This is very interesting.

MR. MIRANDA: Yes. Actually we're in the '70s.

MEMBER WALLIS: Back in the '60s.

MEMBER SIEBER: No, that's 1970s technology.

MEMBER WALLIS: We should all feel really young and full of energy, right?

MR. MIRANDA: LOFTRAN was written in 1970 and was in full use for licensing analysis by 1971. LOFTRAN is an abbreviation for loss of flow transient and it was written to do the loss of flow transient analysis for the Zorita Plant in Spain, a one loop plant.

As far as transient assumptions are concerned, the worse single act of failure in the protection system is assumed, and this goes to the IEEE 279 requirements 279 requirements. And then again, the scram worth is based on the most reactive rod stuck outside the core.

And we heard a little bit about this earlier, about no credit for operation of control grade systems. And typically these are the pressurizer PORVs, heaters and spray. And such systems are assumed not to be operating in a transient unless their operation would tend to make the transient worse.

Sometimes you'll see in a set of accident analyses several cases performed with and without the operation of the control grade system to see the effect.

And then there are some trips that are just not taken credit for. And the example of the reactor trip on turbine trip was alluded to earlier. And also the rods don't fall into the core when offsite power is lost. The rods fall into the core only after reactor trip signal is received.

I can discuss, by the way, before I get into the transients, if you're interested I could talk a little bit about the overtemperature delta T trip and how that's determined.

At this point I'll go to the conclusions. The bottom line, very simple, when we look at an analysis, for example the DNBR limit. If the minimum calculated DNBR from the transient is greater than the safety analysis limit, then the analysis is acceptable.

If the minimum calculated DNBR should equal the safety analysis limit, then the analysis is still acceptable because we know that we have margin in both the limit and in the accident analysis.

And if the minimum calculated DNBR should fall below the safety analysis limit, now we can't accept the analysis because it hasn't been demonstrated that there's adequate margin still available. There's obviously been some erosion of that margin and we have no idea of how much is remaining. And this goes back to what you said, Dr.

Wallis. We don't have that relationship between the best estimate value and the uncertainty.

MEMBER WALLIS: Now when the licensee calculates these numbers, he's not able to tweak his code to make it less than or more than? We all know that by changing nodalization and time steps and all sorts of things you can tweak codes to get different results. He's not allowed to tweak his code? How do you prevent him from just dialing a lot of tweaks and eventually getting within the regulations?

MR. MIRANDA: Well, we can't prevent him from doing that. And if the modeling has been accepted; an acceptable model should not be very sensitive to things like time steps and nodalization for a non-LOCA analysis.

DR. BANERJEE: They generally are, that's the problem. I mean, essentially all these finite difference code depend on nodal volumes and time steps. They're not mathematically convert in any sense of the word. They're too nonlinear. There's also some weird things in them.

MEMBER WALLIS: Like the business of matching the currant number at one and not somewhere else, and therefore getting distortion there.

MR. MIRANDA: You can tweak the code a

little bit, but only a little bit with LOFTRAN because LOFTRAN is not like a LOCA model. It's a hard wired simulation. It has a pressurizer. It has steam generators. And you have very little leeway as far as nodalization is concerned. You can put three nodes in the hot leg or you can put 20 nodes in the hot leg; the results should not be that much different.

The same thing with the core. You can put several nodes axially and radially in the core but, it won't have that much of a difference.

MEMBER WALLIS: That's why we've always said that the Staff should have the ability to run these codes itself. Find out how sensitive they are to these various things rather than just taking something submitted by the licensee, who has obviously optimized things to make it look good.

MR. MIRANDA: As a matter of --

MEMBER WALLIS: Or he has the chance to do that, let's say. But you don't have these Westinghouse codes run by the Staff, do you?

MR. MIRANDA: Well, for Beaver Valley and Ginna we do have use of the LOFTRAN code. We have access to the LOFTRAN code through Westinghouse's office in Rockville. And we have the LOFTRAN manual and we have the safety analysis standards.

MEMBER WALLIS: When they report a number like, whatever it is, 2748.5 when it should be 2750, you can run your own LOFTRAN or whatever it is and figure out if you can get it to 2502.1 or something?

MR. MIRANDA: We could, yes.

MEMBER WALLIS: 2750.3 or whatever it is.

MR. MIRANDA: Yes. Yes. We could change a few parameters --

MEMBER WALLIS: You have a really good idea of how much tweaking they could do to get what they want?

MR. MIRANDA: I've done this tweaking myself.

MEMBER WALLIS: That's it, you're an insider.

MR. MIRANDA: There isn't that much you can do. You might be able to change the result by a couple of psi, but unless you make some basic changes in the assumptions. You would need, for example you would need to change the critical flow model that you're using. And making changes like that require justification. You need to have a reason for doing that.

MEMBER WALLIS: It really takes a Staff member who has done this stuff him or herself to be able to understand what the licensee is doing or what Westinghouse is doing. Otherwise you can be bamboozled.

DR. BANERJEE: Or have an equal capability, which is not LOFTRAN, which is in your hands.

MEMBER WALLIS: Like TRAC?

DR. BANERJEE: Whatever, yes.

MEMBER SIEBER: Yes. Well, LOFTRAN is only one code. There's a lot of codes that are used here.

DR. BANERJEE: Yes.

MEMBER SIEBER: There are VIPRE, MAAP.

DR. BANERJEE: At least to keep them honest to do a few spot checks here and there.

MR. MIRANDA: Yes. And we have done a couple of those.

MEMBER SIEBER: They do audit. You do audits?

MR. MIRANDA: Yes. We did an audit for Beaver Valley in November of last year, three days at Westinghouse's offices in Pittsburgh where we looked at the --

MEMBER WALLIS: When are we going to take a break?

MR. MIRANDA: -- analyses, we looked at

the calculation notes behind the analysis and also the safety analysis standards. And we talked to the people who performed these analyses.

CHAIRMAN DENNING: Sam, let me interrupt you at this point. I think this is a good breaking point, would you not agree?

MR. MIRANDA: Sure.

CHAIRMAN DENNING: Well in that case, we're going to adjourned then until by that clock 25 after 1:00.

(Whereupon, at 12:30 p.m. the meeting was adjourned, to reconvene this same day at 1:30 p.m.)

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

1:30 p.m.

CHAIRMAN DENNING: Okay. We are now back in session.

And, Sam, you can start anytime you want.

MR. MIRANDA: Okay. I will step through three example of non-LOCA transients. And we have the same three transients that Beaver Valley was talking about earlier.

The first is a loss of external load. And this is the event that causes a very high reactor coolant system pressure. And followed by the rapid draw of power for the channels to DNB. And finally the spurious actuation of ECCS. And this event is the one that we look at in order to show that the event will not progress to a condition III or IV event.

The first event, the loss of external load I might comes in several varieties. There is a condition I loss of external load, an operational transient which is also known as a load rejection. We can reduce load by 50 percent and show that the plant will not trip.

There's also a loss of load ATWS, which is the limiting ATWS event in terms of pressure which will reach pressures very close to the 3200 psi limit.

The loss of external load, and moving to the earlier discussion, the best estimate case that showed there was no difference between pre-EPI and post-EPU, I might add that in that instance if you have a loss of load and you have the steam dumping available, basically that amounts to a 60 percent loss of load. Steam dumping to the condenser will take up about 40 percent of nominal steam flow. So comparing that to an accident analysis loss of load, a 100 percent load rejection, there's a big benefit there; first of all. And secondly, if you use the pressure control system pulls and spray the spray will be working during that event. So that seeing two curves that are identical is not a surprise because here you only have a 60 percent load rejection and you have pressure being controlled by the sprays. And that is very likely to be more than enough to handle the 8 percent power increase.

So for this event there are two cases analyzed. I'm going to talk about both of them and you'll see why in a few minutes.

The first case we have a case that's analyzed for channels to the DNB. And in that case as expected the overtemperature delta T trip is reached. And the minimum DNBR occurs shortly after the rods begin to drop.

Typically the minimum DNBR will occur even before the rods reach of the bottom of the core. When most of activity has been inserted, transient is already -- DNB ratio begins to increase again.

One thing I would look for in as a reviewer in a case like this would be for a reactor trip that comes from the part of the reactor protection system that is designed to protect against a parameter of interest. In this case we're worried about DNB and the reactor protection system function that protects against DNB is overtemperature delta T. So if I saw a trip occurring from another source that is not related to DNB, I would have questions.

So here we have the overtemperature delta T trip operational.

The second case is the case that challenge the RCS pressure limit. So here we have the nuclear power and heat flux. Then I have drawn on this the time of the reactor trip right here. And you'll see that the nuclear power begins to drop quite soon. Heat flux begins to drop just a little bit later. And that's just due to the thermo-lag heat flux through the fuel.

And this is the pressure and pressurizer volume.

MEMBER WALLIS: Now it peaks out at the flat top because it actually blows a relief valve, the pressurizer?

MR. MIRANDA: This is the answer to your question right there.

MEMBER WALLIS: Okay. That's it. Thank you.

MR. MIRANDA: Now this is an example of conservatism in the setpoints. The pressurizer safety values are set to open nominally at 2500 psia with a tolerance of plus or minus 3 percent. This is Beaver Valley 1. And in this case since they are looking for a low DNB ratio, they're want to keep the pressure low. Therefore, they're using the low setting on the pressurizer safety valves, opening them at 24, 25 psia, nominal minus 3 percent.

They're also using pressure control. Pressurizer spray and pressurizer power operator relief valves. So you see the first plateau is when the relief valves open at 2350 psi and a second plateau is when the safety valves open. Both of those serve to keep the pressure low and keep the DNB ratio low.

And then finally as a verification that

this is not an event that could proceed to a more serious event, we see that the pressurizer does not fill.

MEMBER WALLIS: Where is full pressurizer?

MR. MIRANDA: It's about 1428 cubic feet. 1420 cubic feet for the pressurizer and another 28 cubic feet for the surge line.

CHAIRMAN DENNING: Now, in this case if they had the valves opening later, would it have threatened the pressurizer more filling the pressurizer?

MR. MIRANDA: If the valves were opening later --

MEMBER WALLIS: It's not turned around by the valves.

MR. MIRANDA: No, actually if the valves opened earlier, the pressurizer level might be higher because you're squeezing the steam out.

This is the last of that transient. This mainly shows that the reactor coolant system pressure here, this is the value that comes very close to the 2750 psi limit. And this is higher than the pressurizer pressure because this pressure is measured at the reactor coolant pump discharge. It's the highest pressure in the system

MR. CARUSO: Do we have that one?

CHAIRMAN DENNING: I don't think we do.

MR. MIRANDA: No. No, I just added that just to show this. I don't think you have any of the curves, do you?

MEMBER KRESS: Yes.

MR. MIRANDA: Okay. I just added that.

And then finally we have the parameter of interest, the DNB ratio to show that it doesn't reach the safety analysis limit. The limit is 1.55. This is the same curve that the reactor trip noted there. And you see that the reactor trip and the minimum DNB ration are related. The reactor trip is what mitigates this event. This is the classic definition of a condition II event. All it takes is a reactor trip.

Now we have another case without pressure control. This is a case that's designed to maximize the reactor coolant system pressure. And this will have a higher pressure than the previous case. It's still within the limit.

A similar behavior, there's the reactor trip and the response in nuclear flux and heat flux. And this occurred you saw earlier today was the peak reactor -- here's a peak pressurizer pressure. And then you come down, on the way down, you see there's a little plateau here. This is at 2575 psia

MEMBER WALLIS: It doesn't look right. Oh, yes it does. It's okay.

MR. MIRANDA: 2575 --

MEMBER WALLIS: Yes, it's okay.

MR. MIRANDA: -- that is nominal subpoint for the pressurizer safety valve.

MEMBER WALLIS: Around the peak. There's a very sharp peak there.

MR. MIRANDA: Oh, that's the reactor trip.

MEMBER WALLIS: The reactor trip is what cuts if off at 2700 or something. That's the way you want to avoid. It just trips in time, doesn't it?

MR. MIRANDA: Yes. Yes. That's right.

MR. FREDERICK: This is Ken Frederick.

Actually, what we've seen is that when the valves open is where we reach the peak. We actually ran an additional case where we didn't credit the first trip, we credited the second trip. And that trip actually occurred after the peak. And the peak was pretty much the same but it occurs right when the valves open.

MEMBER WALLIS: So it's a valve opening that causes the peak?

MR. MIRANDA: Well, the valve opening helps. In fact, this 2575 here, that's when the valve begin to reseat. And that's the higher -- that's the nominal setpoint plus 3 percent. Because the object here is to maximize pressure. So they're using the higher setpoint for the safety valves. And also in this case we see that the pressurizer doesn't fill.

This is another curve that you don't have. This is the reactor coolant system pressure to show the maximum value. That's the number that you saw earlier, the 2747 psia.

We can skip this one.

MEMBER WALLIS: So you're making FENOC's presentation for them here?

MR. MIRANDA: Excuse me?

MEMBER WALLIS: This is all their results, right?

MR. MIRANDA: Their results, yes.

MEMBER WALLIS: And so you're just showing that you understand them? There's nothing that you did to calculate anything separately?

MR. MIRANDA: Actually, I did --

MEMBER SIEBER: He probably do it.

MR. MIRANDA: I did the analysis that Mr. Frederick was referring to.

MEMBER WALLIS: Oh, you did the analysis that they're using now?

MR. MIRANDA: No, no, no no. The one where they took the second trip, I verified the LOFTRAN ran.

MEMBER WALLIS: Okay.

MR. MIRANDA: That is designed to show that these valve sizing meets the ASME design criteria. That's according to Section 5.2.2 in the FSAR.

Any questions on the loss of load?

As I said, the loss of load there's a different of different variation. We've already referred to four variations. The accident analysis, the condition I event which could be a load rejection anywhere from 40, 50, 60 percent, the ATWS analysis; that's three variations.

Okay. Rod withdrawal with power. Rod withdrawal with power is actually a series of transient analyses that could be -- let's see, close to a 100 different analyses that are performed. I'm going to talk about two example.

One, at full power and 80 PCM reactivity insertion rate, a high reactivity insertion rate and another one at full power with a very slow reactivity insertion rate.

And these two events show that the high neutron flux trip will protect against a high insertion rate and the overtemperature delta T trip will protect against very slow insertion rates.

There are other trips that come in, but these are the ones that we look for in a rod withdrawing power since these are directly related to the event.

Here's the high reactivity insertion rate. And we see we get the high flux trip. And there's about a half a second delay and the rods begin to fall. And as the rods fall, you can see the power dropping. This is a very short time scale. It's only 7 seconds.

And since this is a condition II event, they're also in addition for looking for the DNB ratio limit, we're also making sure that the pressurizer doesn't fill. In this case there's lot of margin to filling.

DR. BANERJEE: What is the water volume for filling the pressurizer?

MR. MIRANDA: 1400 cubic feet plus another 28 cubic feet for the surge line.

So the DNBR safety analysis limit is 1.55

and this particular case the ADPC per second reactivity insertion rate at full power meets the limit.

And then for the slow reactivity insertion rate, you can see this is a much longer transient. We have about 2 minutes represented here. And the trip comes from the overtemperature delta T trip. And this event, by the way, is crucial to determining the setpoints for the overtemperature delta T trip.

And in this case we see that the pressurizer power operator relief valves opened right here. But the pressurizer is still not full.

And here's the DNB ratio. And in this case we come closer to the limit. I think that might be the 1.57 case. DNB ratio is reached soon after the -- while the rods are falling into the core.

And those are two cases, as I said, of many more, possibly up to a 100. And the results of all these cases are plotted in something like this.

As I said earlier, the cases that have a very high reactivity insertion rate along here are protected by the high flux trip. And the cases that have slow reactivity insertion rates are protected by the overtemperature delta-T trip. And actually these curves continue. I think they go like this. Okay.

But this plot shows that it was protected through this very wide range of reactivity insertion rates, wider than you might expect during operation by these trips, the overtemperature delta T and the high neutron flux.

And I have more results along those lines. This is at 60 percent power. And then at 10 percent power.

That's the rod withdrawal of power analysis. Any questions on that?

Okay. These DNB ratios, by the way, that you see here are calculated by LOFTRAN, not by VIPRE. And they used that derivative estimation method.

Now the next event, the spurious actuation of safety injection at power is probably the only event in Chapter 15 that actually challenges that criterion that prohibits escalation of a condition II event into a more serious event, at least that's the only one we know of. And the mechanism is that you have a spurious SI signal, a fairly common event, a condition II event and causing the safety injection system to actuate. And in some plants, like Beaver Valley, the safety injection system includes the charging pumps. And the charging pumps are capable of pumping into the RCS at nominal pressure. In fact, their shut off head is at 2600 psi. So they can not only can they pump into the RCS nominal pressure, they can lift safety valves.

If they fill the pressurizer and lift out of the PORVs or the safety valves, then the question is if these valves are not qualified for water relief, the deterministic accident analysis methods assume that such valves once opened would stick open. And that would be a condition III event, a small break LOCA.

Beaver Valley is a little bit unusual compared to other Westinghouse plants. Beaver Valley has three PORVs rather than two.

Another interesting aspect of this accident is that it's misunderstood, it has been misunderstood in terms of its analysis. I've seen analyses in licensing basis that talk about DNB ratio and how DNB ration safety analysis is met. Even some analyses that talk about RCS pressurization or overpressurization. Neither is of concern.

First of all, the safety injection signal will automatically trip the reactor that's in the protection system. The reactor trips immediately. So there's no danger of DNB.

And secondly, since the shut off head of the charging pumps is only 2600 psi, there is no danger of exceeding 110 percent of design pressure.

So those two concerns go away and we're left with the escalation to a condition II event.

So this illustrates how the graphic trip occurs immediately. And we have the core temperature, core average temperature dropping and then eventually coming up to this level here. This is about 563. And basically what this temperature is determined by the secondary side temperature.

The steam generators sitting at about 1100 or 1200 psi perhaps the safety valves are open. Saturation temperature at that pressure is about here.

This is the pressurizer volume, the pressurize fills here. And we see that the cycle to safety valves, we have four openings. And doing the review I questioned the PORVs. Certainly the licensee said, well we don't need the PORVs. We're not going to take credit for the PORVs. We're qualifying the safety valves for water relief. So we'll use the safety valves to mitigate this event as we see here. Safety valves are opening and closing. And they qualify for water relief, so we can expect them to close as designed.

However, the PORVs are going to be there. And the PORVs will open first unless you have them blocked. I don't think that would be very likely. But the PORVs once opened, you have to be sure that they will close.

To qualify PORVs for water relief it takes two steps: (1) the valves themselves have to be qualified for water relief along with the discharge piping, and; (2) the automatic control circuity for the PORVs has to be safety graded. And normally that's not safety graded.

And that's there to guarantee that the PORVs will open when required and will close when required.

In this case since the PORVs are not being credited for mitigation of the event, we need to worry only about the closing. In other words, if the pressurizer fills and pressurized by the charging pumps, it's possible that the PORVs will open. If they open, we need to know that they'll close. If they don't open, then we know that we have the safety valves available. And this is what the transient here shows; that the safety valves will handle this event.

So in response the applicant pointed out the protection grade signal on low pressurizer pressure that will automatically close the PORVs if they should open.

MEMBER SIEBER: On the other hand if the PORV is not tested and qualified to pass water, even though you get a close signal, it may not close, right?

MR. MIRANDA: Yes. The EPRI valve tests were used to qualify the PORVs for water --

MEMBER SIEBER: So they will close?

MR. MIRANDA: They will close if they get a signal.

MEMBER SIEBER: Okay.

MR. MIRANDA: This is the mass flow rate for the safety valves on the four openings.

MEMBER WALLIS: They will close if they get a signal? Don't they sometimes stick?

MR. MIRANDA: Well, for the purpose of the analysis if the valve is qualified under these conditions, if PORV is not only used for steam release; if it's qualified for water relief, we will assume that it operates as designed. Because the valve is qualified for water relief. And it is safety graded, by the way. The PORVs themselves, the components are safety grade. The problem is that the circuitry is not safety graded. There are a couple of single point failure vulnerabilities in the circuitry that need to be corrected. That's for the opening circuitry.

For the closing circuitry that signal comes from the protection system. So there will be a reliable close signal.

MEMBER WALLIS: I thought TMI had a signal that didn't close for mechanical reason. TMI had boron deposits or something that stopped that closing. Hey, you have plenty of signal.

MEMBER MAYNARD: Okay. But for this accident you could have the same situation if a qualified safety relief valve sticks open. Hence, you go into your small break LOCA analysis. For this analysis you're assuming that the valve closes there. It for any reason it did not, you're still covered by your small break LOCA analysis.

CHAIRMAN DENNING: And if you have a monitor that says it didn't close, then you can close a block valve the PORV?

MR. MIRANDA: Yes. Those are practical considerations which are not relevant here.

CHAIRMAN DENNING: In regulatory space you're saying?

MR. MIRANDA: Right. Because here they're concerned about meeting that ANS criteria that says you can't go to a condition III event. So if it sticks open and if you're doing things like closing the block valve, you're mitigating a condition III event. You've already violated the criteria.

This is also important here. This pressurizer water temperature. The EPRI valve tests showed that safety valves and PORVs, but safety valves can be expected to function as designed if the water temperature does not get too cold. For Crosby safety valves which are installed in Beaver Valley Unit 2, the temperature must not go below about 613 degrees.

MEMBER SIEBER: Put them in a box and put a heater in there.

MR. MIRANDA: Excuse me?

MEMBER SIEBER: Put them in a box and put a heater in there, which is what they did.

MR. MIRANDA: And for Beaver Valley Unit 1, which has Target Rock safety valves, they're much better off with the water temperature for those valves has to be above 330 degrees.

So these two plots are fairly important. Eventually if you continue this, you will get below 613 degrees. But we can expect operator action to occur before then. And this is the way the event is mitigated. There's no automatic protection system function such as reactor trip or other function that will mitigate this event. It takes operator action. An operator must shut down the charging pumps. And once that's done, the event is basically over. And that will occur before the temperature reaches 613 degrees.

Westinghouse plants, there's a class of Westinghouse plants in which Beaver Valley is included but Ginna is not which use the charging pumps in the safety injection system. And therefore, are susceptible to this kind of a situation. And there are ways to show that ANSI criteria is met.

One is to show that the operator acts before the pressurizer fills to shut off the charging flow. Another is to qualify the PORVs and to relieve water by qualifying the PORVs themselves and the discharge piping, and correcting the automatic control system's circuitry. And six plants have done that; Diablo Canyon, Callaway, Millstone have done that and Salem also.

And the other option which Beaver Valley has taken is to qualify the safety valves along with taking credit for the closing signal coming from the protection system.

So those are the three transients. Any questions on those?

CHAIRMAN DENNING: Large LOCA lines, too? I didn't see it in the handout.

MR. MIRANDA: No.

CHAIRMAN DENNING: No? So you don't have any large LOCA --

MR. MIRANDA: No, I don't.

CHAIRMAN DENNING: So basically for this part you're done then?

MR. MIRANDA: I'm done, unless you have any questions or you wish to talk about overtemperature delta T or anything else. Do you want to see transients like this for Ginna on Thursday.

CHAIRMAN DENNING: Yes.

MR. MIRANDA: Okay.

CHAIRMAN DENNING: Okay. We're done? Yes.

Okay. Thank you.

MEMBER WALLIS: Let's go back to modern technology now. Note how sharp the last slides were. You could even read the small print on those.

MR. FREDERICK: Again, I'm Ken Frederick. I'm here to talk about the balance of the safety analysis for Beaver Valley.

The last four subject areas we're going to talk about small break LOCA, close LOCA long term cooling and boron precipitation as well as containment, containment conversion program primarily, containment overpressure credit and we'll briefly touch on the dose assessment results.

To start off with small break LOCA. As mentioned earlier, we're using NOTRUMP, which is the current licensing basis for Beaver Valley and Westinghouse approved methodology.

We have made some modifications to the plant in order to retain or regain some of the margin that we're losing for the EPU. The primary change here is the higher head or higher capacity, high head safety injection pumps. The increased flow associated with that modification is around 5 percent.

We're also replacing some instrumentation that gives us lower uncertainties which are factored into how we set up the system, throttling.

We also increased the minimum SI accumulator pressure and that provides some benefit for the small break LOCA analysis.

During the course of the Staff review for the small break analysis several questions were raised for us to address. The first one dealt with the methodology which Westinghouse was using concerning the break spectrum.

Typical practice having to analyze

integer break sizes, for example 2", 3", 4". And the Staff felt that that was too course to capture the maximum PCT.

Another issue which was raised was loop seal clearing assumptions. The approved methodology allowed for loop seal clearing on the broken loop but not the intact loops. And our EPU analysis we had other opinions of that methodology. Had actually credited loop seal clearing on the intact loops as well. So the Staff asked us to address that.

Another request from the staff was that oxidation results for local oxidation needed to include pre-transient oxidation. That's the oxidation which occurs over the normal life of the fuel.

Another issue which was raised here was for some of the smaller small breaks in the analysis these things tend to hang up in terms of the PCT. And primarily that's -- in fact, we reached kind of a stagnation point.

The operators normally have a response within a fairly small time frame. And we see the slides of the PCT curves, we'll maybe talk about this some more. Basically the concern here was that the operator actions needed to be done in a timely manner so that we could demonstrate refill of the core.

DR. BANERJEE: There's lots of little slides that we are missing.

MR. FREDERICK: Pardon me?

DR. BANERJEE: The previous one you had those --

MEMBER SIEBER: He wants to see in that little box.

DR. BANERJEE: Then give us an option.

MR. FREDERICK: This is basically a pictorial explanation of loop seal clearing if you had a question about what that is. Loop seals, of course, are across under leg

CHAIRMAN DENNING: Go ahead. You can proceed.

MR. FREDERICK: So we addressed the Staff questions in this area. We did the analyses. We've looked at break sizes down to quarter inch increments. The allowance for loop seal clearing on the intact loops within the analysis.

We also do -- normally this is always done, but the burnup studies we did for oxidation and that's looking at oxidation over the life of the fuel. And we've included the pre-transient oxidation in that calculation to show that we met with the pre-transient.

This is the spectrum sizes that we've analyzed starting at 2 inch and going all the way up to 6 inch. And in between 2 inches and 3 inches we ran these smaller increments.

You can see there that the case of Unit 1 the peak clad temperature, the highest case ended up being 2.75 inches where previously I think it was 3 inches. And for Unit 2 the worse case is still 3 inches. But, yes, there is a small -- something on the order of for these analyses I think up to 60 degrees. For example 3 inches or 2 3/4 inches.

The other thing to note there as you get into the smaller break sizes you can see that the transients well out here past close to an hour. And the theory there was that we need to take operator actions, which is primarily to pull down, depressurize, which allows the vessel to refill in that time frame.

DR. BANERJEE: Do you get reflux condensation in the steam generators for any of these break sizes?

MR. FREDERICK: Josh from Westinghouse.

MR. HARTZ: Yes, this is Josh Hartz from Westinghouse. I'm in charge of the neutron small break LOCA evaluation model.

Yes, after the single and two phase natural circulation period when that mechanism breaks down, the steam generators go into reflux cooling mode and NOTRUMP does model that.

DR. BANERJEE: And all break sizes or some break sizes and when does natural circulation stop and when did you get into refluxing?

MR. HARTZ: Well, it's going to vary with break size. If you get into larger break sizes, you depressurize so quickly that you lose two phase natural circulation so quickly that the break becomes the dominant means of energy removal. So the reflux condensation aspects tends to increase as break size increases.

DR. BANERJEE: So at 2 inch, say, you'd get refluxing but at 6 inch you wouldn't?

MR. HARTZ: More so than you would in the 6 inch break, that's correct.

DR. BANERJEE: Okay. Now you're going to get more steam flow to the steam generator because your power is greater by 10 percent, roughly, here?

MR. HARTZ: That's correct. Your boil off.

DR. BANERJEE: Now refluxing is effected by flooding at the steam generator tube sheet inlet, right? So can your steam generator inlet flow is roughly the same because it's the same flow area that you have. Does the 10 percent increase in steam flow lead to more water hold up in the steam generators or not?

MR. HARTZ: NOTRUMP does show some liquid hold up in the steam generators, but it doesn't tend to dominate the results too much because we only see it in the smaller breaks. But the --

DR. BANERJEE: Do you get any core level depression due to that?

MR. HARTZ: Due to liquid holdup in the steam generator we have seen it, but that tends to make the results more conservative because the differential pressure is driven up and it tends to drive mixture level down. And sometimes make the break flow stay at a low quality two phase mixture for a longer period of time.

DR. BANERJEE: When you do these reflux calculations, do you get flooding at the inlet of the steam generators due to the steam flow or are you away from flooding? Flooding defined as Graham Wallis would.

MEMBER WALLIS: CCFL.

DR. BANERJEE: CCFL.

MR. HARTZ: The mechanism that we've seen for these, and in some cases we have seen some flooding, but again it was for smaller breaks and that mechanism tends to break down rather quickly. And so it doesn't tend to have much dominance on the transient.

DR. BANERJEE: Well, I'd be interested to see the difference in this due to the increased steam flow rates as to whether you get a more extended period of flooding or not compared to pre-EPU as opposed to post-EPU conditions. Because you're getting 10 percent more flow rate, right? Now whether this is giving you a larger period of flooding or not is interesting for me to know.

So you take the 2 inch break, it doesn't really matter.

MR. HARTZ: Okay.

DR. BANERJEE: Okay. Because you say flooding breaks down quickly. It would only break down if the core level went down somewhat so your steam generation rate went down or because you're getting the same stuff out of the break anyway, right,in rough terms?

MR. HARTZ: That's correct, yes.

DR. BANERJEE: At these conditions. So whatever goes to the steam generator is coming from the core. So you're getting 10 percent more the core. So you would expect you'd get a more extended period of flooding and more liquid hold up in the steam generators and a larger core level depression. So I'd like to see how -- just if we do this by hand, you can more or less work it out using Graham's flooding criteria CCFL to see whether this is in correspondence with what you would expect by a hand calculation or not.

MR. HARTZ: Well, one thing I might add is there were some air water tests done with the steam generator inlet plenum that were performed very early on in NOTRUMP's development. And the model would be based on that data. And what we could do is take a look and see how the EPU would impact that.

DR. BANERJEE: Right. But there was periods of this that occurred in Semiscale as well, if I remember. So presumably NOTRUMP has been sort of validated against those data as well?

MR. HARTZ: Yes, we used Semiscale as part of our validation package.

DR. BANERJEE: So you've got some high pressure validation data, too, right?

MR. HARTZ: That's correct.

DR. BANERJEE: Hopefully. So anyway, it's worth finding out. Because one of the key aspects of this higher steam generation rate is the potential for more liquid hold up. I'm not saying it would happen here. It depends on the flow area of the steam generator, all these things, obviously. So we take a look at this aspect.

Thanks.

MR. HARTZ: Okay.

DR. BANERJEE: How many tubes are plugged, you know, all this.

MR. HARTZ: Well, we assume different plugging levels for each unit because Unit 1 has the newer generators. Obviously, there would be less tube plugging involved.

I believe Unit 1 assumed 10 percent and Unit 2 22 percent.

DR. BANERJEE: Okay.

MR. FREDERICK: Let's go to the next backup slide.

This is a plot which shows the transient oxidation which is calculated over the burn up life of the fuel, the red line. The green line is a representation of a pre-transient type oxidation. Normally that would go to zero at zero burn up. However, this is cut off here at conservatively at about 4 percent.

And blue line is the addition of those two.

So we show that over the life of the fuel, 17 percent criteria including pretransient oxidation.

MEMBER WALLIS: There's that much pretransient oxidation? Yes, there is.

MR. FREDERICK: Yes. Essentially that number corresponds to a fuel design limit. Now, typically the actual does not approach that limit and it's probably 50 to 75 percent of that. But it does represent an upper bound that we use in the fuel design.

Next slide, please.

This shows the results for the EPU analysis as well as the current small break LOCA analysis. You see here all the acceptance criteria are met plus some 2200 for PCT and the hydrogen are below the respective limits.

And this analysis reflects the modifications we made to increase SI flow as well as the accumulator pressure. So those changes tend to offset the effects of EPU.

MR. HARTZ: Dr. Wallis, in case you're wondering, those maximum hydrogen generation rates, we just look at the hot assembly average. And if it's less than 1 percent, that's what we declare. But in reality, as you know, not all the assemblies operate at that power. So if you were to do an actual rod census, it would be something much less than that.

MR. FREDERICK: No more questions on small break. We're move on to post-LOCA long term cooling. And this is the analysis that we do to demonstrate that we do not reach precipitation limits for boron in the core following a LOCA. And another criteria for this analysis is that we show that we have enough flow to meet the boron off and the flushing requirements.

CHAIRMAN DENNING: And what did you have as the backup on this one. Because I'm definitely interested in some particular. What's your backup say?

MR. FREDERICK: This backup just shows the alignment, the system type alignment for hot leg recirculation.

CHAIRMAN DENNING: Okay. We may come back to it. So go forward.

DR. BANERJEE: So you switched to hot leg?

MR. FREDERICK: On Unit 1 we switched to a simultaneous hot and cold leg injection.

Again, as part of the NRC review we had

some questions in this area. Some of these were associate with I think some issues that came up from Waterford. There were issues that we were asked to address for this particular analysis, the first one being core voiding must be part of the calculation for the boron build up. There's some effects such as low pressure drops are needed to be included.

If we were using a boric acid solubility limit higher than base do pure water and boron or elevated temperatures, then we needed to justify that.

And the Appendix K decay heat was the used analysis.

So, again, in this case we redid the calculations taking into consideration these issues.

CHAIRMAN DENNING: Now you're going to have to help me because -- maybe it'll be clear on the next. I'll wait before I ask some more questions.

MR. FREDERICK: So for the core voiding aspect of this, we did more voiding calculations on a transient basis using a modified Yeh Correlation.

CHAIRMAN DENNING: Now I don't understand that. What does that mean, Yeh? You're using what kind of analysis to determine what's happening within the core and --

MEMBER WALLIS: Some sort of heat flux or something or it's a -- isn't that the same thing. It's how you calculate the void fraction.

MR. FREDERICK: I'll ask --

MR. FINK: My name is David Fink. I work for Westinghouse.

Dr. Wallis, that's correct it's kind of a drift flux. It's a way just to calculate the voiding.

MEMBER WALLIS: I think it's actually benchmarked against the rod bundles and things. Real Geometry is like this, so --

MR. FINK: I believe it is.

CHAIRMAN DENNING: Okay. Now tell me again. The vehicle that's doing the analysis, how is it modeling the system?

MR. FREDERICK: It's a fairly simplistic analysis. Essentially you're looking at the core and then the boil off rate and the --

CHAIRMAN DENNING: So it's the equivalent of a RELAP analysis where you would look in -- and why not? I'm missing how you're going to determine -- I'm concerned about the way volumes are mixed under the assumption of when the boron concentrates and you get increased density there, it's not clear to me that you're adequately considering what's really happening axially up the channel and whether as you get more and more bubble formation within the channel, whether that's offsetting the increased density due to concentration of boron. Can you give me a better idea as to how you're actually analyzing the flow characteristics of what's happening in the core.

MR. FREDERICK: Dave, do you want to take that?

MR. FINK: Yes. This is David Fink again.

If I could take a minute here and just explain. The original analysis that we did for the Beaver Valley EPU actually in the time line was several years ago. So they were actually pre-Waterford uprate. Okay. Those analyses used a simple control volume calculation and much as we've done for 25, 30 years for hot leg switch over calculations.

And in those simplified control volume, you have a boiling pot, you have steam coming out, you have borated water going in and you build up boric acid in the core region. Okay.

So for the uprate the difference is more power, more boil off, faster build up. Okay.

In that very simplified approach there were two big conservatism at least as we believe it. And the first was how we selected the control volume. Okay. The control volume that's historically been used didn't include any of the lower plenum. It didn't include any of the volume --

MEMBER WALLIS: Uniform mixing in this whole control volume? Surely when you have boiling in a channel the boron is sort of pumped along and then as the steam evolves, the boron's left behind. So it concentrates at the top, doesn't it?

MR. FINK: Well, our simplified model assumed complete mixing in the core region.

MEMBER WALLIS: There's some experiments that show that's reasonable?

MR. FINK: Well, we believe there's quite a bit of circulation going on in the core region. For example --

CHAIRMAN DENNING: Why do you believe that? Why do you believe that? That's what I want to know.

MR. FINK: Well, we've looked at our large break LOCA WCOBRA/TRAC code and we've looked at what happens in the core region in that code.

CHAIRMAN DENNING: Now, which specific accident is the one of concern here?

MR. FINK: This is all large break.

CHAIRMAN DENNING: Large break?

MR. FINK: Yes, sir.

CHAIRMAN DENNING: Okay. So that you have essentially atmospheric conditions at the outlet, is that true?

MR. FINK: Yes, sir.

CHAIRMAN DENNING: Okay. And you have a big level swell kind of situation in terms of the voiding -- as you get near the upper part, there's a bigger and bigger froth.

MR. FINK: Okay. Well, I can just continue here.

CHAIRMAN DENNING: Yes.

MR. FINK: So that was what we originally did for the first go around.

MEMBER WALLIS: Dry regions? If you have dry regions presumably the boron's left behind on the wall.

DR. BANERJEE: If there was core uncovery.

MEMBER WALLIS: Right. Or you had spattering, a spattering of cooling and you have spattering cooling rather than froth cooling, but the boron's left behind on the wall.

CHAIRMAN DENNING: If you'd like to use that board over there to illustration, you can also do that. If that would help.

DR. BANERJEE: Back to that screen.

CHAIRMAN DENNING: But not the screen.

MR. FINK: I might do that.

So in response to NRC RAIs, and this was largely I guess posed Waterford fallout and specific RAIs asked by the Staff for these calculations, we did this work. Okay. And we addressed the four things that are listed up on the board, most significantly was the use of Appendix K decay heat, which these calculations have always been based on a best estimate decay heat. And so we used Appendix K decay heat. We also calculated a time based core voiding. And all that does is that reduces the liquid volume in your control volume. Okay.

So we did those calculations. Because we are now taking a lot of liquid volume out of the core region we choose to credit some volumes that were not previously credited, and probably the most significant is the one that was discussed during the Waterford EPU, which is the lower plenum.

MEMBER WALLIS: There's an experiment. I'm trying to remember the name of it, isn't there?

MR. FINK: It was the MHI BACCHUS Test.

MEMBER WALLIS: BACCHUS. It was a god of some sort. BACCHUS. This seemed to show that things really were mixed?

MR. FINK: Yes. Yes, it did.

MEMBER WALLIS: Surprising to us.

MR. FINK: It clearly showed --

DR. BANERJEE: Yes, it is surprising. Can you explain that test again.

MR. FINK: Well, the test clearly showed the point at which the denser higher concentrated region up in the core becomes dense enough to displace the less concentrated volume in the lower plenum. So in the test you could clearly see as the --

MEMBER WALLIS: Heavy concentrate --

DR. BANERJEE: I mean isn't there a countervailing flow which is balancing that?

MR. FINK: Well, under this scenario this is a cold leg break where all your excess SI flows out the break. So more SI doesn't help you. You basically have a stagnant boiling pot and you're feeing through the lower plenum enough to make up boil off, but --

DR. BANERJEE: And that's not enough for the density head being developed? It allows you to settle the borated water against that flow?

MR. FINK: Well, the flow that's coming in is coming from the sump and it's coming --

MEMBER WALLIS: In the BACCHUS report?

DR. BANERJEE: Who did these experiments?

MR. FINK: MHI.

DR. BANERJEE: Who is that?

MR. FINK: Mitsubishi Heavy Industries.

DR. BANERJEE: And these were done where in --

MR. FINK: These were done in a scale facility they did specifically to look at this. Because Japanese plants to this day still use a 24 hour switchover time, which was the original Westinghouse design.

MEMBER WALLIS: So it's a big facility, as I recall. It was scale, but it was still fairly big?

MR. FINK: Yes. It was a slab model, so it was like full length, 180th scale, I believe.

DR. BANERJEE: And so they had borated water boiling off on heaters or something?

MR. FINK: Correct.

DR. BANERJEE: And they had a lower plenum markup and they looked at the density profile?

MR. FINK: Well, they had it highly instrumented with boron sensors and temperature sensors. And we wrote a summary report that was presented for the Waterford EPU. And I'm sure the NRC has a copy of it. It's very interesting.

DR. BANERJEE: But do you have a copy of the BACCHUS report itself?

MR. FINK: It's a MHI test, so we wrote a summary report that is part of --

MEMBER WALLIS: Right. I saw it. I think it was in the Waterford context. We spent some time on this.

MR. FINK: Yes.

DR. BANERJEE: So your contention is that the whole thing is well mixed, not just the core.

MEMBER WALLIS: So what's your point? But once you get enough density difference it turns over, doesn't it?

MR. FINK: That's correct. And we'd like to credit the whole lower plenum to give us a little better answer, but we conservatively credited as was done for Waterford. We just credited 50 percent of the lower plenum as being a reasonably conservative approach.

DR. BANERJEE: What happens if you don't credit it?

MR. FINK: Well, it's just how much liquid volume you have in your calculations. So you have --

DR. BANERJEE: Right. So suppose you just stayed with your old assumption of allowing mixing in the core region and nowhere else?

MR. FINK: Well, then the boric acid would build up faster.

MEMBER WALLIS: I guess we had a lot of questions previously about whether just looking at solubility limits was good enough when you're boiling off this -- when it gets concentrated the boron, presumably, can precipitate around nucleation sites and things like that. It's not as if just solubility alone is governing whether or not you get some precipitation. And if you have some drop wise cooling, then if a drop evaporates it leaves behind its boron. So we had questions of that type. I don't know if they were ever answered. Because you just look at the overall solubility, don't you?

MR. FINK: That's correct.

MEMBER WALLIS: I think we asked the Staff to look into this, didn't we, Ralph?

MR. CARUSO: Yes. And they presented.

MEMBER WALLIS: Yes, then we were satisfied. We spent some time on it, I know.

DR. BANERJEE: So are we revisiting something that was --

MEMBER WALLIS: Yes, we went into it. We spent a whole day or something like this.

DR. BANERJEE: Done.

MR. CARUSO: Yes.

MEMBER WALLIS: But you should get the BACCHUS report.

DR. BANERJEE: All right.

MEMBER WALLIS: It's all about Roman orgies and things like that.

DR. BANERJEE: It sounds like it.

MEMBER WALLIS: It's a good report. You should get it. It could tell you some things that wouldn't be intuitive if you just thought about it.

CHAIRMAN DENNING: I'd like some information on the third bullet on --

MR. KELLERMAN: Yes. My name is Brett Kellerman. I'm with Westinghouse. And we can get access to a summary report of the BACCHUS test that we brought for the Waterford --

MEMBER WALLIS: We probably have that in the record somewhere. The Waterford record, we have it. You can just pull it out and give it to him.

CHAIRMAN DENNING: But you do it, like in the third bullet there, you do have some information on sump additives as they effect boric acid solubility, is that what I'm seeing there?

MR. FREDERICK: Yes. Similar to what

Waterford had at I believe their TSP plant.

MR. FINK: Yes. This is Dave Fink again.

In these analyses we do not credit any elevated solubility limit due to sump additives for this uprate.

MEMBER WALLIS: Additives are presumably chemicals?

MR. FINK: Yes.

MEMBER WALLIS: They're not fibers?

MR. FINK: I hope not.

DR. BANERJEE: There's also a possibility that it wouldn't mix because there'll be enough fiber at the core inlet, right?

MEMBER WALLIS: Well, that's another question. Yes.

MR. FREDERICK: We did a test using sodium hydroxide and we found that the precipitation limit increased from 29 percent up to about 48 percent. But we are not crediting that as part of our analyses. And we did use decay heat.

MEMBER WALLIS: It should be part of the sump question, though, when you get fines going through the screens. Would that make any difference to his picture?

MR. FREDERICK: Yes. That's something that

I believe is going to be addressed as part of the downstream --

MEMBER WALLIS: Under GSI-191.

MEMBER WALLIS: -- effects under GSI-191. Yes.

DR. BANERJEE: Suppose that it didn't mix outside the core region, for whatever reason, it could be that the core inlet is blocked with debris --

CHAIRMAN DENNING: The problem may be worse than that if that happens.

DR. BANERJEE: Well, there's some bypass paths through the --

MEMBER WALLIS: The sump?

DR. BANERJEE: Yes. So then what happens to the boron if it's boiling off happily in the core without this assumption of mixing with the lower plenum? Is it then an untenable --

MR. FINK: Yes. You'd have a precipitation limit much sooner and --

DR. BANERJEE: Yes. Is it an untenable situation then or is it still okay? Do you have to make this assumption or do you not to make it liveable?

MR. FREDERICK: Well, if we ended up with a shorter time, say 3 hours or 4 hours or something, not necessarily --

DR. BANERJEE: Is that still okay?

MR. FREDERICK: --untenable but we would have to look at what our makeup rates could be. So we did a test here as we need enough flow to meet the boil off and also flush the core.

DR. BANERJEE: Because if I remember the report that was circulated by Ralph, you have 6 hours to do the switchover, is that right?

MR. FREDERICK: That's correct.

DR. BANERJEE: Yes. So at the moment if you didn't credit half the lower plenum, which is a large volume, and only had the core, would this be like 2 hours, 1 hour, 3 hours? What would be that number?

MR. FREDERICK: Do you have a feel for that, Dave?

DR. BANERJEE: Because the volume is very different, right?

MEMBER SIEBER: Yes.

MR. FINK: This is Dave Fink.

The lower plenum's actually a pretty good size volume, but because we're crediting half of it, it probably represents maybe one-fourth -- maybe one-third, one fourth of the total volume. So it would --

MEMBER WALLIS: So it would feed or something in total --

MR. FINK: Correct.

MEMBER WALLIS: And the core --

MR. FINK: So is representing a third of the volume you'd increase.

DR. BANERJEE: Well, what is the core volume that you're crediting?

MR. FINK: I believe with the one-half lower plenum volume and the core voiding, we're probably -- I'd say approximately 900 cubic feet.

DR. BANERJEE: And of that about 300 is lower plenum?

MEMBER WALLIS: Half of it. Half of it.

DR. BANERJEE: Half of it.

MEMBER WALLIS: A 150.

MR. FINK: I'd say that's --

DR. BANERJEE: So the core volume is so large.

MEMBER WALLIS: Don't get it all because there are voids in it.

DR. BANERJEE: I see.

MR. FINK: Well, it's core and upper plenum, so it's --

DR. BANERJEE: Well, why the upper plenum if it's boiling off. Wouldn't that get full of steam or something?

MR. FINK: Well, we look at the way this calculation is done, we do the voiding at the top of the core at the core exit. And we apply that voiding up through the upper plenum. So the upper plenum does contribute.

DR. BANERJEE: But the upper plenum is not empty in this case?

MR. FINK: That's correct.

DR. BANERJEE: So the steam is going out through the hot leg, is that right?

MR. FINK: Correct.

DR. BANERJEE: Eventually it makes its way out to the cold leg break somehow, around the circuit?

MR. FINK: Correct.

DR. BANERJEE: So why is the upper plenum not full of steam?

MR. FINK: The upper plenum would be full of some mixture, some voided --

MEMBER WALLIS: Otherwise you can't drive the water along the hot leg, presumably.

DR. BANERJEE: There's no water going on--

MEMBER WALLIS: Right. You dry out --

DR. BANERJEE: It's mainly steam, right?

It's mainly steam going along?

MEMBER WALLIS: Yes, but --

DR. BANERJEE: Maybe a sketch would help because I'm sort of a bit lost as to where all the water is in this system. So can you just sketch it?

MR. FINK: Ken, do we have a backup slide that might have that?

DR. BANERJEE: I mean the simple control volume approach is great, but we got to put the water in the right places here.

MR. FINK: Well, we don't credit anything outside of the vessel, outside of the inside of the core barrel actually in this calculation. So we don't credit any of the volume in the former region or the downcomer.

MEMBER SIEBER: Or that?

MR. FINK: No, no.

MEMBER SIEBER: That's a significant amount of water.

MR. FINK: Yes, sir.

DR. BANERJEE: Yes. Show us what you're crediting --

MEMBER WALLIS: Here are the levels down below the hot leg.

DR. BANERJEE: That's what I thought it

would be, but for some reason you have a volume of mixing above.

MR. FINK: Well, in that picture everything we're crediting is right inside that inside cylinder that represents the core. So we don't crediting anything outside of that.

MEMBER WALLIS: Credit the downcomer at all?

MR. FINK: Correct.

DR. BANERJEE: Okay. So how much is that volume that you would credit if you didn't credit any piece of the lower plenum here?

MR. FINK: Up to the bottom of the hot leg, I believe it would be 1,000 cubic feet.

MEMBER WALLIS: With the bubbles or not?

MR. FINK: That would be total volume.

DR. BANERJEE: Only the core?

MR. FINK: Correct.

DR. BANERJEE: Okay. And then if you credited 50 percent of the lower plenum, it's another 300.

MEMBER WALLIS: One fifty.

MR. FINK: Approximately.

DR. BANERJEE: One fifty. Okay. So it's not such a big deal.

MR. FINK: It's actually a little more than 150, I believe.

DR. BANERJEE: All right. I think that's fine. If that -- that sounds good.

MEMBER WALLIS: Well, I think the thing is when you're so close to the limit, you've got to darn sure that it's well mixed. Because all you need is to have a little bit of nonmixing and you have twice as much concentration in the top as in the bottom and you get precipitation. So you really have to study the BACCHUS report to be convinced that there's good mixing.

MR. FINK: There are some other conservatism in the methodology. For example, we don't credit any entrainment around the loops that might take place early on where you'd expect to carry a lot of water around the loops. So we start our problem from the beginning. And that probably represents a great deal of conservatism.

We've always had trouble identifying exactly how much entrainment you'd get around the loops.

CHAIRMAN DENNING: Do you know offhand what the void fraction is in the upper plenum that you're talking about? What's the void fraction?

MR. FINK: Probably I'm guessing 70 percent.

CHAIRMAN DENNING: Seventy percent?

MR. FINK: Seven percent.

CHAIRMAN DENNING: Even though there's that much void fraction, the density of that material is higher than the density of the material than the cold water in the lower plenum?

MR. FINK: It would be the density of the liquid, and you'd have to as you went down into the core and into the periphery is where you'd be much less voiding.

MR. FREDERICK: This slide actually shows the collapsed liquid load that was calculated.

DR. BANERJEE: Where's the bottom of the core?

MR. FINK: The 12 foot level there is the top of the core. So that's collapsed liquid level.

DR. BANERJEE: Right. But where is the bottom of the core?

MR. FINK: Zero.

DR. BANERJEE: Zero? All right.

MEMBER WALLIS: At some previous time this was dried out on top?

DR. BANERJEE: At zero -- time zero.

CHAIRMAN DENNING: Right. This is much later. Sometime it was dried out.

DR. BANERJEE: Early times.

MEMBER WALLIS: And when it was dried out didn't you get boron precipitation on the dried out part?

DR. BANERJEE: That was the large break LOCA.

MEMBER WALLIS: Yes, but you get it in the small break, too, otherwise you never get these high temperatures. Well, they get boron pleating on these tubes. But anyway Staff convinced us that we're not to worry about it I think before.

MR. FREDERICK: Go back one slide.

MEMBER WALLIS: Move on probably.

CHAIRMAN DENNING: Yes. Right. Let's move on. I think some of us are going to want to look at that BACCHUS report again today.

MEMBER WALLIS: Because it's a very interesting subject.

MR. FREDERICK: In the draft SER there was an item identified as a contingency for this particular analysis. And it has some discussions with the Staff about that issue. It's described here, and basically the concern was that for smaller breaks we need to demonstrate the capability that we'll be able to cool down before the precipitation time in order to be able to -- the actual injection on the hot legs. An we've had some discussions with the Staff on that issue. And Dr. Ward will be talking about that later. At this point we're convinced we have a --

CHAIRMAN DENNING: I guess I'm a little bit confused about the difference between large LOCA case and then the small LOCA cases that you were talking about as far as what the conditions are that could lead to precipitation and can you help me there?

MR. FREDERICK: Well, I think for small breaks typically and your temperature and your pressure is going to hang up. So precipitation limits are very high under those conditions. The concern would be that borrowing that scenario who hold on the pressurization mode, want to make sure that you get to the cooled down condition before you reach precipitation limit for the cold condition. That, again, is a function of the operator response to the event.

DR. BANERJEE: Because if you inject in the hot leg, you get cold water into the core, right? Is that the concern?

MR. FREDERICK: That's not the major

concern. The major concern is depressurizing enough so we get hot leg flow. Because for Unit 1, anyway, we're aligning the low head pumps to the hot legs and it would have a shot off pressure of around --

MEMBER WALLIS: Once you get hot leg flow, you just flush the boron out.

DR. BANERJEE: Yes.

MR. FREDERICK: Again, Dr. Ward will be discussing --

MEMBER WALLIS: Now you need to keep enough boron in to avoid criticality concern? And you've already scrammed the reactor --

DR. BANERJEE: Well, the water's is borated, isn't it?

MEMBER WALLIS: Yes. Don't you need still boron for the criticality.

DR. BANERJEE: In the injection --

MEMBER SIEBER: The injection water is refueling water.

MR. FREDERICK: So again, we have addressed the questions that were raised by the Staff for this analysis and the results showed for Unit 1 6½ hours is the required switchover time, 6 hours for Unit 2.

In our procedures we actually make

preparations to do that realignment an hour ahead of time. The actually alignment is only a matter --

MEMBER WALLIS: This time depend on the break size?

MEMBER SIEBER: It should.

MR. FREDERICK: Essentially no, because at the point where we're starting the calculations you're fixed in terms of the volume of water in the --

DR. BANERJEE: Well, in long term cooling, which is within an hour --

MEMBER WALLIS: -- off to atmospheric without any break size contributing.

MR. FREDERICK: Yes, heat boil off at that point.

MEMBER WALLIS: At the point of water boiling, essentially an open top.

CHAIRMAN DENNING: But it's still pressurized.

MR. FREDERICK: Large break, it's not in the small break.

CHAIRMAN DENNING: Right. But in the small break it is.

MEMBER WALLIS: Well then how much is pressurized must depend on the break size?

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: And so the time surely depends on the break size, doesn't it?

MR. FREDERICK: David?

MR. FINK: This is David Fink again.

The effect of some pressure assumption in the vessel really helps you in the voiding. So at higher pressures you get a lot of this voiding --

MEMBER WALLIS: You have more water there.

MR. FINK: A lot more water.

MEMBER WALLIS: So there's nothing magic about 5 hours, is there? I mean sometimes it depends on the break size. So what it is the operator measures so that he knows he has to do something?

MR. FREDERICK: From the start of the event.

MEMBER WALLIS: But he doesn't know the break size, so he doesn't really know --

MR. FREDERICK: Yes. The time that we're calculating it represents the bounding case.

CHAIRMAN DENNING: The bounding case?

DR. BANERJEE: Doesn't he have some indicator to know when it would be prudent to switchover? Like isn't there a measurement of some sort that --

MR. DURKOSH: I'm going to try to answer

that. This is Don Durkosh from FirstEnergy.

The emergency operating procedures are based on the limiting large break LOCA switchover time. We do not have any other measurements. We basically will follow our EOP network and we'll be in our E1 procedure waiting for this switchover time to occur, and then we'll be preparing for it. And we'll initiate switchover. So there is no other measurements. In theory, we don't know where the break size is so we set it up for the most limiting conditions there.

MEMBER WALLIS: If it were smaller, he would have longer time?

DR. BANERJEE: So there are no criteria which requires switchover?

MR. FREDERICK: They're all the type criteria --

DR. BANERJEE: No, no, no. Physical criteria.

MEMBER WALLIS: There's not a measurement that you compare with some other measurement --

DR. BANERJEE: Now I'd better switch because things are getting bad or something.

MEMBER WALLIS: No. He's just told within so many hours to do it.

MR. FREDERICK: There's no way to measure the boron --

MEMBER WALLIS: He has to remember?

DR. BANERJEE: Really of the neutron flux, right, in the core? You still have some sort of a flux measurement, right, something?

MR. FREDERICK: Yes. I guess if the source range was operational still, yes, we would have some indication. I'm not sure how you would correlate that to boron levels, though.

DR. BANERJEE: So you don't have a measure of boron? So you have no measure of boron in the core basically?

MR. FREDERICK: Dave, did you have something?

MR. FINK: This is Dave Fink.

Actually, they don't do it but you could in theory measure the boron by the boron concentration in the sump because all the boron that you're leaving behind in the vessel is coming from somewhere. And that somewhere is the sump. So as the vessel concentration's building up, the sump is diluting. So theoretically you could --

DR. BANERJEE: But is the sump so large in volume that dilution would be relatively small compared to the --

MEMBER SIEBER: It would not look the same as the core condition from a chemistry standpoint. Concentrating mechanisms in the core, the sump has everything else.

DR. BANERJEE: Right.

MEMBER SIEBER: And so the concentrations would be different.

DR. BANERJEE: Would be not -- yes.

MEMBER SIEBER: Does -- help you at all in knowing where you're at?

MEMBER WALLIS: At levels lower in the core?

MEMBER SIEBER: Yes.

MR. DURKOSH: This is Don Durkosh again.

MEMBER WALLIS: EOPs don't speak to that.

MR. DURKOSH: Yes. The switchover time is institutionalized in the EOPs. They're consistent for all Westinghouse plants. And this is the approach that we've been using since literally day one. We use these times as the time to go ahead and initiate switchover to hot leg recirc.

DR. BANERJEE: It could be too early, it could be too late; we don't know. There's no way to know.

MEMBER SIEBER: Well, it's based on the analyses.

DR. BANERJEE: On calculations, right? Who knows what these calculations mean, how good they are.

MEMBER WALLIS: But it's been done since day one.

MEMBER SIEBER: The calculations were done by the Westinghouse owners group at the time that the guidelines were done.

DR. BANERJEE: Therefore they must be good?

CHAIRMAN DENNING: So this is how it's changed by the EPU?

MEMBER SIEBER: That was back in 1981 or '82.

MR. FREDERICK: If you consider the calculations bounding and very conservative, as this slide shows you here, we actually ran cases with more realistic assumptions. And you can see trying to get to the limit, which is 29 percent here. Well, you can't actually see it. But considerable difference when you consider better estimate type assumptions. And, Dave, maybe you can --

MEMBER WALLIS: More significant perhaps

is the effect of EPU on this?

MR. FREDERICK: No, this is just --

MEMBER WALLIS: No. More significant would be to show the effect of EPU?

MR. FREDERICK: Well, the EPU ended up reducing the time from 8 hours to 6½.

MEMBER WALLIS: Yes.

MEMBER SIEBER: And that's basically due to the increased decay heat.

MEMBER WALLIS: Yes. But you assume that's not critical? I mean, it's still got an awful long time.

MR. FREDERICK: Yes. Again, it's not challenging the operators to get it done. So the more meaty concern with shortening that time is that the higher you go up on the decay heat curve, the more flow you need. And --

MEMBER WALLIS: There's some sort of alarm clock that starts when there's a break and then after 6 hours says you'd better switchover injection or is he supposed to keep track of all the time?

MEMBER SIEBER: You have blogs.

CHAIRMAN DENNING: That's a good EOP question, I think.

MR. FREDERICK: Yes.

MR. DURKOSH: This is Don Durkosh again.

The operating crew would keep track of what time the reactor trip and we'd have the technical support center available to us, we have our STAs available to us. So we have multiple people basically keeping track. And we have an explicit step in our E1 emergency procedure. We would transition back into our E1 procedure and we'd basically, the next step would be when you approach the hot leg switchover time, begin making your preparations.

So we have various people that would tab of that time.

MEMBER WALLIS: It still would be good if you had something that alerted him. I mean, if I have to cook something, I don't really look at my watch all the time. I like to have a timer that tells me when to switch things off or take them out of the oven. But this is an EOP question.

I think the more you can take away from the operator having to remember things, the better. You have something which actually tells him he's got to do something.

But anyway, it's not really --

CHAIRMAN DENNING: I think we're ready to move out of that into containment analysis.

MEMBER WALLIS: Yes, I think -- yes.

MR. DURKOSH: This is Don Durkosh.

We do have timers in the control room

MEMBER WALLIS: You do?

MR. DURKOSH: But unlike cooking, we do also have a lot of people available to us.

MEMBER WALLIS: Too cooks --

MR. FREDERICK: Too many cooks in the kitchen.

MEMBER SIEBER: You have to remember to turn the timers over.

CHAIRMAN DENNING: Go ahead and continue.

MR. FREDERICK: Okay. I'm going to move on to containment analysis. Again, the containment analysis was submitted actually a little earlier than EPU in june of 2004, and that was approved in February of this year.

And it was a conversion, which mean we went from a sub-atmospheric design to an atmospheric. The difference there being that in the atmospheric design there's no requirement to contain or to get back to sub-atmospheric conditions post accident, which we had previous to the change.

The primary effect of EPU, which was factored into this containment conversion program, was the M&Es from the primary system and the steamline break. Those are really the things that are directly affected by the increase in power.

The mass and energy release calculations for this program use the Westinghouse approved methodologies, and that wasn't a change.

For the containment integrity, part of the calculations, we utilized MAAP-DBA, which is a modification to MAAP 4 which changed some of the containment calculations.

It's similar to the other codes which have been used or approved for applications such as GOTHIC, COCO.

The program the containment uses traditional heat transfer correlations such as Tagami and Uchida. That's consistent with other applications.

For the NPSH calculations we've incorporated a multi node model. And that allows us to get better details on where water is held up in containment and certain volumes. At the box area you can jus see the nodal model that we used. Eighteen nodes.

For small break analyses, and we've done a much more extensive look at small break primarily for sump inventory questions. For that analyses the mass and energy releases were calculated using MAAP. And those results were benchmarked against the code primarily.

The actual operating containment pressure will still be slightly sub-atmospheric at the site 14.3 approximately is atmospheric pressure. And our operating range will be 12.8 to 14.2 absolute.

The older operating pressure, which is actually an air partial pressure limit, was about 4 pounds lower. So at these higher pressures we eliminate the need for applied air when we do make entries, which is a very nice benefits in terms of personnel safety.

MEMBER SIEBER: Well, and you have decompression in the airlock, which is a time consumer and hard on some people, hard on your ears.

MR. FREDERICK: As part of this analysis we've also credited the various modifications which are beneficial. Replacement steam generators for Unit 1, for example. These generators have the restriction nozzle in the outlet where our old ones did not. So we're looking at 4.6 square foot main steamline break versus a 1.4 square feet. So that is a big benefit for the steamline break analysis.

Also the feed isolation and the cavitating venturies, again, limit the mass energy release during a steamline break.

MEMBER MAYNARD: Are those new valves or just new actuators or --

MR. FREDERICK: They're brand new valves and actuators.

MEMBER MAYNARD: Okay. Are they replacing existing valves that are there or --

MR. FREDERICK: There was an existing valve there. I believe we turned that into a check valve, is that right?

MR. TESTA: Yes. This is Mike Testa, Beaver Valley.

Yes, like Ken was saying, we had a check valve in the system that had a motor on it. And what we ended up doing was we restored that to just a normal or simple check valve. And then in the piping system we added a brand new feed isolation valve. New valve, new actuator controls.

MEMBER SIEBER: It is hydraulic or electric or --

MR. TESTA: Hydraulic. Yes.

MR. FREDERICK: We've also added a cord from the reactor cavity so there's the general basement area that allows the water that normally hold up in that cavity to drain back into the sump, which helps out with our inventory issues.

This QS cutback was a feature that we used to extend the spray at Unit 1 that helped us maintain some of the spurious condition. We don't need that any longer so we're eliminating it.

And again, the setpoint for transfer to recirc was lowered under this program and that gives us a little higher sump level at recirc, which helps out with the NPSH.

For the analysis, essentially acceptance criteria that we look at:

Peak pressure, of course, less than the design, which is 45.

Containment pressure reduction of 50 percent, that's essentially an assumption that's made in the offsite dose analysis so we need to demonstrate that we can met that;

NPSH. We need the required NPSH for the pumps which takes suction out of the sump, and;

When the pumps start we look at minimum pump inventory to make sure we don't have any vortexing issues.

MEMBER WALLIS: Of course, that's all

assuming that the screens don't have too much deposited on them?

MR. FREDERICK: Correct.

MEMBER WALLIS: What kind of insulation do you have on this?

MR. FREDERICK: Insulation?

MEMBER WALLIS: Yes. Kind of insulation? Do you have fiberglass or --

CHAIRMAN DENNING: That's the physics.

MEMBER WALLIS: But I wasn't here. I wasn't here. I'm sorry.

CHAIRMAN DENNING: If you could give a little summary.

MEMBER SIEBER: It's reflective.

MR. FREDERICK: But I know and then Mark can maybe jump in. We do have RMI reflective on many of the components. We do have CALSIL.

MEMBER WALLIS: You have CALSIL?

MR. FREDERICK: Yes. We have CALSIL and we have something Min-K, which I -- it's a fiber.

MR. MANOLERAS: This is Mark Manoleras.

We have very small quantities of that material. We're going to target that for removal, that material for removal.

DR. BANERJEE: That's the only fibrous

material? Is that the only fibrous material?

MR. MANOLERAS: That would be our predominant fibrous material.

DR. BANERJEE: And do you have aluminum as well?

MR. MANOLERAS: Yes, we do. Yes, we do. And we actually have a program which takes a look and monitors and maintains the quantities of aluminum in containment. We know exactly what we have. Zinc and aluminum in containment.

MEMBER WALLIS: You have TSP in the sump?

MR. MANOLERAS: No, we do not.

MR. FREDERICK: Carbon hydroxide.

MEMBER WALLIS: Carbon hydroxide.

MR. MANOLERAS: Correct.

DR. BANERJEE: Carbon hydroxide and aluminum is --

MEMBER WALLIS: Yes.

CHAIRMAN DENNING: You can continue. Thanks.

MEMBER WALLIS: Yes.

DR. ELAWAR: This table shows the peak pressure results for the LOCA and steamline breaks as well as the pre-EPU results.

You see here, for example, Unit 1

steamline break, that pressure actually went down even though we're analyzing for EPU conditions. And, again, that's reflecting the beneficial modifications that were made there.

And essentially all these results benefit to some degree from the methodology change to MAAP-DBA. Again, we're raising initial pressure 4 pounds for these, so obviously we're getting some margin.

CHAIRMAN DENNING: When you show the pre-EPU, is that post-containment conversion?

MR. FREDERICK: No.

CHAIRMAN DENNING: No, that's pre-containment--

MR. FREDERICK: Prior.

MEMBER WALLIS: That's using a previous method of calculation?

MR. FREDERICK: Yes. It's using the Stone & Webster program.

MEMBER WALLIS: Okay.

DR. BANERJEE: What is the difference in the methods of calculations which give you the slide again?

MR. FREDERICK: Hit the backup slide.

This slide shows essentially how the peak pressure is sensitive to airborne water fractions. And that water fraction is essentially the water coming out of the break, what percentage of it is actually entrained into the atmosphere. In the previous methodology essentially there was no entrainment assumptions. It looked at other programs such GOTHIC. GOTHIC actually assumed a 100 percent entrainment.

MEMBER WALLIS: Oh.

MR. FREDERICK: And when we looked at this, the curve basically once you get to 10 percent, you don't get much more benefit. But 10 percent --

MEMBER WALLIS: There's a fog in there, you're saying there's a fog in there?

MR. FREDERICK: Yes. The water at entrainment essentially acts like an additional heat, so it gives you a benefit in the peak pressure.

MEMBER WALLIS: Airborne water fraction is the faction of the water which is entrained?

MR. FREDERICK: Yes.

DR. BANERJEE: Emitted?

MR. FREDERICK: The fraction of the water that is coming out of the break that is entrained.

MEMBER WALLIS: I would think getting a 100 percent of it would be a bit of a struggle, getting it all help up in the air. It's going to fall out, isn't it?

MR. FREDERICK: Well, some of it is, yes.

DR. BANERJEE: I think, I mean most of it.

MEMBER WALLIS: Most of it.

MR. FREDERICK: Well, we did provide as part of the submittal, we provided some comparisons to experimental data. I don't remember the experiments right off hand. But those results showed somewhere in the 50 to 60 percent range were entrained.

DR. BANERJEE: But you have surfaces where the water jet impacts, right?

MR. FREDERICK: Yes, and that does account for that. If there is collisions with surfaces and poor condensation for that matter, it is removed in that--

DR. BANERJEE: But nonetheless, it's a heat sink?

MR. FREDERICK: Yes, essentially.

MEMBER WALLIS: When you start out you've got to make a lot of dispersion. But as you put more and more water in there, there must be a lot of it that comes out?

MEMBER KRESS: Why isn't that below 45?

MR. FREDERICK: It's absolute. But this is not for our plant in particular. This is just --

MEMBER KRESS: Oh, I see. This is just for some plant.

MEMBER WALLIS: So what do you do? You assume something here or what?

MR. FREDERICK: Actually, for MAAP we assume 10 percent entrainment.

MEMBER WALLIS: It's just someone's educated guess?

MR. FREDERICK: It was a conservative relative to what we saw in the experiments.

MEMBER WALLIS: Well, it's interesting. How much mass of water is it then when it's 10 percent? Later in a LOCA it's a lot, isn't it? The air is holding all that up?

MEMBER SIEBER: You get a number of them.

CHAIRMAN DENNING: Well, wait a second. This is the large break and early time peak.

MEMBER WALLIS: Time is --

MR. FREDERICK: Yes, this is all currently in the first 20 seconds.

MEMBER WALLIS: So it's probably okay. Early time, yes.

MR. FREDERICK: Yes.

MEMBER WALLIS: Everything's stirred up.

MR. FREDERICK: Yes, it's very quick. Yes.

MEMBER WALLIS: I was concerned when you

say you assume something.

MR. FREDERICK: Just to cover the other criteria and results, we did show that we met the depressurization rate, time. NPSH requirements were satisfied. We also look at EQ, for example, if the envelopes change, we look at the equipment and we've done that. And as well as the structural issues, the piping and the sump inventory.

The next subject which is related --

MEMBER SIEBER: Before you leave, you said that even with the relaxation of the sub-atmospheric requirement you still returned to some sub-atmospheric condition following a LOCA. How long does that take? An hour?

MR. FREDERICK: I'm not sure I said that, Jack. But we can still get there is the river is cold enough. I mean, this is very much a function of the service water temperature.

MEMBER SIEBER: Okay.

MR. FREDERICK: Typically though --

MEMBER SIEBER: You don't necessarily go sub-atmospheric.

MR. FREDERICK: That's right. Right.

MEMBER SIEBER: And so from a Part 100 standpoint if you have some positive pressure --

MR. FREDERICK: And if some leakage occurs--

MEMBER SIEBER: -- you may see it on the outside, right?

MR. FREDERICK: For the dose analyses we assume leakage occurs for 30 days.

MEMBER SIEBER: Okay.

MEMBER KRESS: I think the section there is you use that high for the peak pressure after 24 hours, right?

MR. FREDERICK: That's reduced to half of that within 24 hours.

MEMBER KRESS: Regardless of what it really is? I mean, it's usually lower than that.

MR. FREDERICK: Yes.

MEMBER KRESS: But it's a conservative calculation?

MR. FREDERICK: Oh, yes.

Moving on to containment overpressure. For Beaver Valley Unit 1 the recirc spray pumps have credited in the past containment overpressure as part of our existing licensing basis. And for this analysis containment conversion and EPU we're continuing to credit that.

Unit 2 does not require any containment

overpressure --

MEMBER WALLIS: Are you crediting the same amount of overpressure for the same amount of time?

MR. FREDERICK: I'll touch on that. We have some slides that show that.

Unit 2 does not credit overpressure and never has. Physically the pumps are a lot lower so they don't have a need for that.

The Beaver Valley recirc spray system, essentially this is our heat removal function post-LOCA in the environment that each train consists of a pump, heat exchanger and spray ring. And it takes suction directly from the sump and delivers a spray flow for Unit 1.

MEMBER WALLIS: When you need it is when you have the high pressure in the containment.

MR. FREDERICK: That's correct, yet. The system was primarily designed to give you a rapid depressurization so you could meet the one hour sub-atmospheric requirement.

The backup slide just shows a sketch of the system, basically.

MEMBER WALLIS: Does it show the pressure needs versus time or something like that and how much you're actually crediting?

MEMBER KRESS: They're different.

MR. FREDERICK: Yes.

MEMBER WALLIS: That's coming up?

MR. FREDERICK: About 2 slides.

MEMBER WALLIS: We're waiting for that. That's the bottom line.

MR. FREDERICK: We're there. This slide shows you the containment over pressure required.

MEMBER WALLIS: You need 10 psi.

MR. FREDERICK: The COP required is basically how much pressure do I need above the initial pressure in containment to get enough NPSH. So, yes, when the pumps first start out, and again these pumps start relatively early, 5 minutes after we reach the high pressure setpoint in containment. So the sump is relatively hot at that point and there is not a lot of level. So the NPSH is somewhat limited. So we need containment overpressure at that point.

Well, let me make another point here. This shows the previous results from pre-EPU and actually pre-containment conversion.

MEMBER WALLIS: The Staff didn't give you any trouble with the blue lines so then they're going to accept the red line?

MR. FREDERICK: Yes. The blue line is

occurring, as you can see, for the EPU we're increasing--

MEMBER WALLIS: And you already have? You already have that approved the blue line?

MR. FREDERICK: That's correct, yes. The increase in actual pressure requirement is on the order of 2 pounds. Duration wise this requirement goes below zero, which means that we don't really need overpressure at that point.

MEMBER WALLIS: Not a very long a period of time compared with some plants.

MR. FREDERICK: That's correct, yes. The point here is that it's roughly ten minutes past the start of the pump.

MEMBER WALLIS: And for hours?

MR. FREDERICK: Right.

MEMBER SIEBER: For the inside research spray pump.

MR. FREDERICK: Correct. And this is for the outside.

MEMBER SIEBER: Right.

MR. FREDERICK: It's very similar.

MR. MANOLERAS: This is Mark Manoleras again.

Ken, why don't you go into detail on the testing of the pumps.

MR. FREDERICK: Yes, I'll get to it. It's a couple of slides away yet.

MEMBER WALLIS: Run without this COP?

MR. FREDERICK: Next one.

This slide shows the available overpressure against the required, the two bottom lines being the required. And what you can see here is actually when the pumps start. They actually start delivering flow about 300 seconds.

MEMBER WALLIS: Now this pressure that's available looks very high. Usually people make a lot of conservative assumptions. This looks like the real pressure. You're going up to 40 psi.

MEMBER SIEBER: Yes.

MEMBER KRESS: This is atmospheric.

MR. FREDERICK: This is actually overpressure.

MEMBER WALLIS: Yes.

MEMBER SIEBER: Containment pressure.

DR. BANERJEE: You have a pretty small containment, right, to get that?

MEMBER SIEBER: Smaller than --

MEMBER WALLIS: Usually you have a containment pressure that's high like that which you use to evaluate the integrity of the containment.

MR. FREDERICK: Right.

MEMBER WALLIS: And then you have a sort of minimum curve which has all kinds of conservative assumptions, which is much lower. And I don't see that there.

MR. FREDERICK: Well, again, you may not see it so much in the peak because that's not really effected by what we do in terms of trying to minimize the pressure.

MEMBER WALLIS: It's not?

MR. FREDERICK: You know, it's when you start the sprays and the peak is basically a function of how Tagami ends up. It's based on volume, energy release and the timing. So that's not something that would really change much.

MEMBER WALLIS: So is this blue curve conservatively estimated to be below the real pressure?

MR. FREDERICK: Yes. We do sensitivity studies that look at really the whole event, not just pressure because it's also a function of sump temperature. And some things that tend to reduce pressure also reduce sump temperature. So both of those are in the NPSH equation. So what we have done historically is we do sensitivity studies on all the sensitive parameters and determine what is the minimum NPSH available case, which is what's shown here.

MEMBER WALLIS: Well, this really should say minimum available overpressure or something, not a best estimate kind of calculation.

MR. FREDERICK: No. This is actually the--

MEMBER WALLIS: The conservative minimum.

MR. FREDERICK: This case reflects the minimum NPSH available result.

DR. BANERJEE: No. I mean the blue curve is the minimum containment pressure available? I mean if it's just about --

MR. FREDERICK: It may not necessarily be the minimum available. It's the minimum available associated with the set of conditions that come to this analysis.

DR. BANERJEE: With this -- yes. Sure. But for this set of conditions it's a large break LOCA or something, right?

MR. FREDERICK: Yes.

MEMBER KRESS: We once wrote a letter that said those calculations ought to have probabilities in them to see how much the probabilities overlap to get some sort of probability that you would have --

DR. BANERJEE: No. Uncertainty anyway.

MR. FREDERICK: And we actually have some stuff in here on that, too.

MEMBER KRESS: Yes.

DR. BANERJEE: If not probability, at least uncertainty.

MEMBER KRESS: Uncertainty. Yes.

MEMBER WALLIS: We did write the letter. We got several members who endorsed additional comments, wasn't that --

MEMBER KRESS: Yes, as I recall.

CHAIRMAN DENNING: You only spray in recirculation mode? You don't spray from the refueling water start --

MR. FREDERICK: No, we do both.

CHAIRMAN DENNING: You do both?

MR. FREDERICK: Yes, and that's what you can see here. I mean, we're going from 40 pounds down to nothing in a little over 10 minutes.

CHAIRMAN DENNING: That's due to spray?

MR. FREDERICK: Yes. So once the spray start, we have a quench spray system which comes from the RST which is --

MEMBER WALLIS: If the pumps weren't working, the blue code would be higher? So it's a kind of self-controlling situation?

MR. FREDERICK: That's correct, yes. The reason we need overpressure is because we're running the sprays. And you can see the pressure comes down pretty quickly once those sprays go on.

MEMBER WALLIS: The sprays themselves reduce the overpressure?

MR. FREDERICK: That's correct.

MEMBER SIEBER: And if you didn't have the overpressure, you wouldn't need the sprays.

MR. FREDERICK: The problem with not having the sprays is that it's our only means of getting heat out of the sump.

MEMBER SIEBER: Right.

MR. FREDERICK: We need the heat exchangers more than we need the sprays.

MEMBER SIEBER: Right.

MEMBER WALLIS: When you need the sprays, they work?

MR. FREDERICK: Yes.

DR. BANERJEE: Those little side diagrams, maybe we should get copies of those because they have -- yes.

MR. FREDERICK: Just a point there. Again, that was the NPSH limited case. It's not necessarily the longest duration. For all the cases we look at, the most amount of time that we need for overpressure credit is 20 minutes after the pump starts.

And we did do some testing of these pumps way back in the late '70s. Actually, it was North Anna pump that was tested, but they're basically identical to ours.

Hit this backup slide. They actually ran these pumps at reduced NPSH all the way down to about 4 feet available, the left line there. And basically you can see, as you reduce NPSH below the required, the performance suffers. But they ran these up to about a half hour in this reduced NPSH mode.

MEMBER SIEBER: And they still pump?

MR. FREDERICK: And they still pumped and they tore them down, and there was no damage to the pumps.

DR. BANERJEE: Well, there was some cavitation, but --

MR. FREDERICK: Yes, obviously it's offering in a cavitation --

DR. BANERJEE: Not significant. Not until to --

MEMBER WALLIS: Until they fall off the cliff there.

MEMBER KRESS: Even with the required net positive suction you had some cavitation, right?

MR. FREDERICK: Yes, 3 you're percent reduced by definition.

MEMBER KRESS: Yes. Yes.

MR. FREDERICK: Go back.

DR. BANERJEE: Excuse me. Go back to that slide.

What is there, I can't read that very well, but what is the suction head required. Yes, I can't read the ones on top there.

MR. FREDERICK:

(Off microphone).

MEMBER SIEBER: You have to talk into a microphone.

MR. FREDERICK: Right.

DR. BANERJEE: Is that 16, 14? The four I can read, but beyond 4 I can't read any of those. They're blurred.

MEMBER WALLIS: Are you saying that even if there were no overpressure available they'd still work? If you lacked 10 psi, will they still work or not?

DR. BANERJEE: These are in feet of water, I take it.

MEMBER WALLIS: Twenty feet of water, do they still work at 20 feet of water.

DR. BANERJEE: No, there are 4 feet of water, they would work.

MEMBER WALLIS: Yes, but not at 20?

DR. BANERJEE: No, at 20 they'd work perfectly.

MEMBER WALLIS: Oh. Well, you've got 4 feet, don't you? What is that you need? You need--

DR. BANERJEE: 11.5 feet. Is that your reference is, 11.5 feet of NPSH on this?

MR. FREDERICK: For these pumps the minimum required that we use is 9.8 feet.

DR. BANERJEE: 9.8 feet. All right. So that's the one, Graham, which is the fourth line down from the top.

MEMBER WALLIS: That one there?

DR. BANERJEE: That's your reference, right?

MR. FREDERICK: Yes.

MEMBER WALLIS: And how compact can it get and still satisfy your needs there?

MR. FREDERICK: Four feet available, that would be something around 2 psi overpressure --

MEMBER WALLIS: It's still pumping.

MR. FREDERICK: -- still required.

MEMBER WALLIS: But that's much less than you're asking for?

MR. FREDERICK: Yes. This is a kind of margin we don't use these lower limits in anyway or we don't model the pumps in a degraded performance.

MEMBER WALLIS: It seems to depend a lot on the dynamic head required. How much is the dynamic head required? There's a load line somewhere here.

DR. BANERJEE: Right, that's what I was going to ask. Where is that load line? Just conceptually if you sketch it.

MR. FREDERICK: Well, these pumps normally operate around 33 to 3500 so your system curve comes through here somewhere.

MEMBER WALLIS: So some of those have already crashed and gone over the -- they went over the precipice by the time they come down to the load line?

MR. FREDERICK: Well, yes, you would see a much reduced flow but you would still get some flow.

CHAIRMAN DENNING: But in reality isn't it just a matter that you don't want them to fail. Because suppose for 20 minutes they didn't work and they didn't remove heat, isn't this really a real long term problem that you're concerned about, which is long term heat removal.

MR. FREDERICK: Yes.

CHAIRMAN DENNING: So the fact that they're not able to keep up with heat rejection during this period when you really need it doesn't really matter.

MR. FREDERICK: If we have reduced heat removal, the ultimate effect is that the sump's a little hotter a little longer.

MEMBER WALLIS: So you'll get 2000 GPM instead of 3500 or something?

MR. FREDERICK: Right.

MEMBER WALLIS: And it's no big deal?

CHAIRMAN DENNING: As long as you --

MR. FREDERICK: It only last for 10 or 20 minutes, yes.

MEMBER MAYNARD: I think the more significant part of this what shows is that they operated for a long period of time, it reduced NPSH and did not fail the pumps and they were still in good shape.

MR. FREDERICK: Yes.

CHAIRMAN DENNING: Okay. Continue.

MR. FREDERICK: Next.

We looked from the PRA aspect of this, you know what's the probability of losing containment isolation which could lead to loss of overpressure. And we estimated that to be about one times 10 to the minus 8. And that's based on the LOCA coincident with failure of isolation for the lines that communicate directly with the containment atmosphere. And those lines for Beaver Valley are actually pretty small. The largest such line is a 2 inch line.

CHAIRMAN DENNING: Since you're still operating a little bit sub-atmospheric, does that help your probability here? Do you know that you're isolated?

MR. FREDERICK: Yes. Essentially we would screen out any large preexisting failure because we would notice that if it occurred.

DR. BANERJEE: Is there any interaction with a LOCA which would sort of tend to make you lose containment isolation?

MR. FREDERICK: No. All of our containment --

DR. BANERJEE: Nothing that --

MR. FREDERICK: -- systems are fully qualified.

DR. BANERJEE: Completely independent?

MR. FREDERICK: Yes. We actually did an analysis where we looked at -- you know, essentially run the NPSH cases with holes in containment. And we did up to a 3 inch based on what our penetration size are.

And if you look at the next slide here essentially all the results are on top each other so there is no significant effect of opening a small hole in containment. Again, that was the most probable based on the actual penetration sizes that are open to containment atmosphere.

DR. BANERJEE: But then what happened to the pressure as you open the hole?

MR. FREDERICK: It didn't change much.

CHAIRMAN DENNING: You can't tell at that small hole size.

MR. FREDERICK: Right. Essentially there's a minimal change in the pressure response such that the NPSH margin doesn't change much.

Next slide.

We do a conservative analysis in terms of minimizing the overpressure available. We do not ask the operators to intervene in anyway to try and maintain pressure at a certain value or certain limit to try and assure that we have available COP.

MEMBER WALLIS: Suppose the screens were getting block, how would the operator know it and what would he do?

MR. FREDERICK: I'll let my operator handle that one here.

MR. DURKOSH: This is Don Durkosh again.

Recently, probably within the last year or so, we've implemented sump blockage guidelines. And we've updated our emergency procedures. So basically when we enter the recirc mode we have RNO, response not obtain actions where we would start a pump or verify a pump is running. And we would monitor things like pump amps, discharge pressure and flow. And if we see any variations, then we have a sump blockage guidelines available to us.

And in the big scheme what the sump blockage guidelines really do is have you look for ways to reduce flow, which would reduce the line losses across the sump screens. So basically kind of get you to reduce the flows, get NPSH back into an acceptable range and operate in that mode.

MEMBER WALLIS: You don't backflush or anything like that?

MR. DURKOSH: Not at this time.

MEMBER MAYNARD: I wouldn't think that the things you would be looking for would be much different than what you in mid-loop operation, making sure that your RA pumps are cavitating or lose suction. I mean it would be a similar situation with the sump.

MR. DURKOSH: I agree.

MEMBER MAYNARD: Yes.

DR. BANERJEE: Are we going to talk about sump blockage at some point?

MEMBER WALLIS: Yes, you are.

CHAIRMAN DENNING: You already have as much as we are.

DR. BANERJEE: Because it was be interesting to know how difficult it would be to backflush.

MEMBER WALLIS: I think it's taboo, though.

CHAIRMAN DENNING: Yes, I think we shouldn't be talking about that now, no.

MEMBER WALLIS: That's another subject.

CHAIRMAN DENNING: I mean it's interesting to see what they are going to do.

DR. BANERJEE: But you're going in for an EPU. You may as well put it in.

MEMBER WALLIS: Yes, but it's a generic

issue.

MR. CARUSO: Yes, but it's a generic issue and we don't resolve generic issues.

DR. BANERJEE: Okay. We won't resolve it.

MEMBER WALLIS: You don't dump it all on one licensee.

CHAIRMAN DENNING: We just initiate generic issues under this.

Okay. Proceed.

MR. FREDERICK: Just to finish up this slide, we did look at potential modification that could be made to eliminate the need for containment over pressure and essentially they're all impractical.

MEMBER WALLIS: I'm curious. You're putting in a bigger screen. What design is it?

MR. FREDERICK: Design in terms of -- hit the back slide.

MEMBER WALLIS: This is a whole lot of cylinders or --

MR. FREDERICK: Yes, it's an array of cylinders.

MEMBER WALLIS: An array of cylinders.

DR. BANERJEE: But is this the top hat design.

MR. FREDERICK: Yes.

MEMBER WALLIS: Okay. Ah, so the problem there is to figure out how that performs when you've only tested one?

DR. BANERJEE: Yes, it's the same problem-

MR. FREDERICK: Our testing is actually looking at it.

MEMBER WALLIS: Testing arrays?

MR. FREDERICK: I think we're do a 9 set of array.

MEMBER WALLIS: Oh, okay. Okay. Thank you. That's better than one.

MEMBER SIEBER: It looks like that would take up a lot of space.

DR. BANERJEE: Then it would be prudent to do backflushing.

MEMBER WALLIS: It's not difficult to figure out that works.

MR. FREDERICK: Just summarizing I guess for the containment overpressure, COP is required for Beaver Valley Unit 1 RS pumps. And it's part of the licensing basis. And it's continued to be credited in the recently approved submittal.

We have run these pumps at reduced NPSH with satisfactory results. And we looked at the risk of losing overpressure, and it's very low. And we also looked at modifications to eliminate the need, and they're not practical.

The next two slides --

CHAIRMAN DENNING: You can go quickly on these I think.

MR. FREDERICK: Yes. These essentially summarize the dose assessment results from the accident analyses.

Again, we're moving to full implementation of the alternative source term and we've updated X/Qs with more recent meteorological data and we've also switched to ARCON 96 for the onsite X/Qs.

We've incorporated the results from our control room tracer gas testing.

Unit 2 continues to use the alternate repair criteria, which develops the accident induced leakage limits. And all the results are within the 50.67 limits, as you can see on the next slide.

Again, here the Unit 2 value is maximized based on the alternate repair criteria methodology.

Just to summarize for safety analysis. Again, we've looked at the required events. All the acceptance criteria seem to be met at the EPU conditions. And we feel like we have enhanced the plant in some way with the modifications we've made and are beneficial impacts in terms of the safety margin. And we've been able to retain a lot of the safety margin.

That's it. Any questions?

CHAIRMAN DENNING: Are there any questions on safety analysis here? Anything that we want to prod for more information tomorrow?

MEMBER WALLIS: I want to know what the Staff thinks about the containment overpressure, but that's not any of that today.

CHAIRMAN DENNING: That's to come.

Okay. Thank you very much.

We're now going to go in recess until by that clock up there it's going to be -- we'll make it a quarter of by that clock.

(Whereupon, at 3:33 p.m. a recess until 3:50 p.m.)

CHAIRMAN DENNING: Okay. We're now back in session. And we're now going to hear about the Staff's view of safety analysis SBLOCA.

DR. WARD: Can you hear me? Okay.

My name is Len Ward, I'm in NRR in the code review analysis branch. And what I'm going to talk about, I'm going to talk basically about post-LOCA long term cooling, and that's large and small break, but then I'm also going to talk about short term behavior small break LOCA.

But before I do that, what I wanted to do is just quickly go over the ECCS system that's used to control boric acid, what's the approach. And then I'll talk about large break LOCA and small breaks.

Now Beaver Valley, it's a 3 loop plant. It's about an 8 percent power increase.

MEMBER SIEBER: Do you want a pointer?

MR. LEE: Yes, you know, I thought I had one here. Here we go.

A key ingredient here in this plant is that it has three accumulators. And as you heard earlier, the pressure was increased to 625 pounds and that's key for short term small break LOCA behavior.

And I'll also be talking about the switch to simultaneous injection and because of the way the ECCS is aligned, because of the ECCS configuration, cold let breaks are limiting in this plant for boron precipitation.

As I said, large breaks to control boric acid, you realign the ECCS, that's the high pressure safety injection pump to deliver half the flow in the hot leg and the other half in the cold leg. And I'll be showing you some calculations that I did to audit the precipitation times that the licensee performed.

I'm also going to talk about small breaks. And it was mentioned before, but small breaks you can hang up at a higher pressure. You don't go down to 147 where you're basically at run out on that high pressure pump. You had some intermediate pressure. It could be 200 pounds, 100 pounds. When you split the flow between both legs it's not enough the flush the core. So what do you do? Well, you cool the plant down. And you cool the plant down to a low enough pressure so that you either get it low enough so that you can flush the core when you switch simultaneous injection or you've cooled it down low enough and fast enough so that you refill the RCS with ECCS coolant, you reestablish single phase natural circulation and you disperse the boron. Okay? And I'll show you some calculations that we did to illustrate that.

MEMBER WALLIS: Even though there's a break, you can fill that whole thing?

DR. WARD: That's right. We're talking small breaks, one inch, two inch, three inch; they're really tiny. You'll fill it back up. I'll show you that when I get to the slide.

MEMBER SIEBER: It's the pot. The break's above the pot.

DR. WARD: The break's in the cold leg.

MEMBER SIEBER: Right.

DR. WARD: Or the hot leg. And the alignment is done such that you don't need to know where the break is. And the analysis is done so you don't need to know necessarily. It's nice to know what the concentration in the core and vessel is, but you don't need to know that. If you do a bounding calculation on precipitation time, all the operators have to know is when the accident started and at certain times you just go switch. And it doesn't matter what the break location is or where the break is.

DR. BANERJEE: When the HPSI are there line sizes indicator of the flows or is it --

DR. WARD: No, that's just where it's going.

MEMBER WALLIS: It's not to scale or anything?

DR. WARD: This is not to scale. So what I want to do is to show you for a cold leg break, before you switch to simultaneous injection you're injecting into the downcomer. You're storing some of it out the break.

MEMBER WALLIS: Right.

DR. WARD: But because there's no flush, okay, you're going to concentrate boric acid in the vessel, in the upper plenum in the core. And basically -- let me use this. This is better.

I mean what happens is you're going to fill the downcomer to the bottom of the cold leg. You can't get anymore water in there because the break's there. Anymore water you add spills.

The water that flows in is dependent on the low pressure drop. And the model I'm going to show you, and it's consistent with the licensee and vendor, it considers the pressure drop. So I have a fixed head here. Depending on the core power level, time and the event, that determines the steaming rate. And that determines where the two phase level is. So in the beginning of the transient very early the two phase level is low. It will grow --

MEMBER WALLIS: It's not on top?

DR. WARD: In the beginning, that's right, you've blown down the core. I mean, the whole core is voided. Now you're refilling. This is early. And it's slowly going to fill up. And I'm only going to be able to get enough water in here that the loop resistance will allow me. My ability to get water into this core isn't any better than my ability to relieve the steam around the loop.

MEMBER WALLIS: And the boron comes in and doesn't leave, so it just builds up?

DR. WARD: No. It just builds up. Right. And that's why with cold side injection, that's why cold leg breaks are worse for boron precipitation.

MEMBER WALLIS: You get some water in is because there are other cold legs from that one, so the water can get in?

DR. WARD: That's correct. Yes. There are two other loops. So this is spilling and the other one's keeping me full here. For this plant within about 45 minutes to an hour, the two phased level is up here above the bottom of the hot leg.

DR. BANERJEE: What's the partition coefficient of boron between the steam and the water.

DR. WARD: What's the what?

DR. BANERJEE: Partition. I mean it's partitioned, right?

MEMBER KRESS: It depends strongly on the pressure and temperature.

DR. BANERJEE: I see.

MEMBER KRESS: Low pressure it stays behind and high pressure it goes with the steam. It's a variable

MEMBER WALLIS: With these pressures it stays behind.

MEMBER MAYNARD: Not much stays behind.

DR. WARD: We're assuming the steam does not remove any of the boric acid nor is there taking any credit for any entrainment. You look at the UPTF tests, they show entrainment for about the first 15 minutes. For every pound of steam you're producing, you're taking 2 or 3 pounds of liquid out. So you're not going to build up very fast at all in the first 45 minutes. But that's neglected as well.

I mean so basically what I was going to say, if you want steaming in the core and I fill the vessel up, I'd have water here. But since I had void in it and if the loop pressure drop isn't a consideration, I' going to swell up into the hot leg. And I'll probably swell -- I won't swell the two phase level any higher than within maybe a half of foot to the top of this hot leg because the steam's got to get out and it's going to pressurize. And you're going to sit there concentrate.

Now, they don't take credit for the volume above the bottom of the hot leg. They're just taking credit for the mixing volume here, the core and half of lower plenum. And the void fractions coming off the top of the core early in the event throughout to about 6 hours is anywhere from 80 to about 65/70 percent. So it's pretty high. There's not much liquid in this region hardly at all. I mean, it's very hard. The void fraction, a very healthy steep gradient from zero to 70/80 percent at the top of the core.

MEMBER WALLIS: I asked the question previously, when you begin to get very high concentrations of boron, doesn't that change the formability and the drift flux and all that kind of thing?

DR. WARD: Yes, i think it does.

DR. BANERJEE: I probably does.

DR. WARD: Yes. I mean --

MEMBER WALLIS: But that would make a difference to the carryover.

DR. WARD: What I did in sensitivity studies, you saw the Waterford report in there.

MEMBER WALLIS: Yes.

DR. WARD: I varied the drift velocity by a plus or minus 25 percent. And, I mean, I'll show some precipitation times. But when you're precipitating out around 6 to 8 hours and in reality you're really not going to get there until about 15, 14 or 15 hours and that's where this plant's at. And I'll show you why that is.

A change of 25 percent in the drift velocity is probably not going to make much difference. I mean, if the drift velocity goes down, then I'm going to swell more, I'm just distributing the liquid and steam over a larger volume. I still got the same amount of liquid.

MEMBER WALLIS: The question we raised, which I don't think was every answered, you know when you boil down something like maple syrup it's just like boiling water. But when you get it up to the point where it's strong enough, it boils like milk. It's overflow and go all over the kitchen because the foaming --

DR. WARD: If it foams --

MEMBER WALLIS: It doesn't break. It just--

DR. WARD: I don't think the BACCHUS test showed that, but -- Yes but I mean those are good questions. But what we have done, and I mentioned this to you the last time we talked -- you had a lot of questions --

MEMBER WALLIS: Yes, but answers --

DR. WARD: And you've had a lot of good

questions today, and you haven't got all the answers. And I don't know all the answers because I want to know the answers to them, too.

We sent a letter out about 8 months ago, about a 15 page letter with about 20 or 30 questions asking what's the effect of boric acid on drift velocity, what's the effect on viscosity, surface tension, show us what the concentration profile is across the core, what's the effect of adding debris in here, how does that effect the concentration?

MEMBER WALLIS: Was this all to Beaver Valley?

DR. WARD: All those questions are in there. And we are --

MEMBER WALLIS: Is this to Beaver Valley or is this a generic question to the industry?

DR. WARD: It's not the strict sense generic letter issue. What we've done is we've sent a letter to all the vendors asking them to answer this question.

MEMBER WALLIS: Okay.

DR. WARD: And address these model concerns--

MEMBER WALLIS: So then you'll report to us on what happened some day?

DR. WARD: And we will.

MEMBER WALLIS: Okay.

DR. WARD: But I haven't heard anything yet. I know they're working on it. I think they're still digesting it. And I think they're planning to do calculations, experiments or whatever. And so when that's done, then we will come and present that to you.

MEMBER WALLIS: Okay. Good. Thank you.

DR. BANERJEE: A couple of these questions clearly can be answered fairly easily, viscosity surface --

DR. WARD: Sure. Sure.

DR. BANERJEE: But the drift velocity is more difficult. And I guess maybe the people at MHI would know the answer to that.

MEMBER WALLIS: But does it boil over? We just need to put it on the stove in your kitchen and wait.

DR. BANERJEE: Well, that's a good way to do it, too.

MEMBER SIEBER: Another way.

MEMBER WALLIS: Well, it's best to do it outside on the grill or something.

DR. WARD: Yes, right. Right. Well, those questions have been asked. And again, when we've had meetings with -- when we get some of the results from all these questions, then we'll be happy to share them with you.

MEMBER WALLIS: If I buy some borax and dissolve it in water in my kitchen, can I boil it and see what happens?

DR. WARD: Sure. I mean --

MEMBER WALLIS: Would that be realistic?

DR. WARD: Well, there was a test done, and I probably shouldn't -- you know, I'm not sure if I should mention it or not.

MEMBER WALLIS: Well then don't.

DR. WARD: So I can't. But if you took a plexiglass vessel and pumped borated water into it, an electrically heated core and you pumped it in at the RWC concentration of roughly -- now they're up around 2600 ppm, and if you took pictures of it you would see because if the water's cold coming in the lower plenum, you see some crystallization even on the surface. But the test would probably show mixing throughout the entire lower plenum and core. And there'd be a gradient in there. But once it precipitates, when you hit that limit based on whatever pressure you're at, it's probably going to look like you filled that whole thing up with salt. Lower plenum core and upper plenum is going to be looks like full of table salt, crystals.

But, you know, there may be some worm holes through it. You know, there are some cooling channels that may be there. But that's probably what's going to happen.

But what I'm going to show in this calculation so we don't get anywhere near that --

MEMBER WALLIS: But it would be slurry cool. It would be slurry cooled. It won't freeze up solidly?

DR. WARD: Yes. Probably.

But I want to show you. hopefully we shouldn't get anywhere near there. And there's enough margin to accommodate. We don't feel that there's answers here, we just want to make sure the industry is doing everything consistent. They're not using a 1.0 multiplier. They'll all using appropriate mixing volumes. They're taking credit for the void fraction in there instead of assuming it's full of liquid, and they're not assuming the whole mixing volume is this size from time zero on, because it grows. So let's do it right. And they are doing that. And they're starting to do that now.

So let me just go over some of the assumptions. I've already discussed it. We're only taking credit for half -- they're only allowed to take credit for half the mixing volume in the lower plenum. The core and the upper plenum, they choose to just credit the volume below the bottom elevation of the hot leg.

Now this was done during the Waterford review, and you'll remember that. I did some calculations. Compared my model to that. And as I recall, it's been a while since I looked at it, the reason why we did this is because since it's an average concentration, it more closely tracked the concentration near the top half of the core instead of some lower average. So they're only allowed to take credit for half of the lower plenum. And I think there was some mixing in the upper plenum, too. But we predicated the precipitation time within an hour. So for a crude model like that, it's probably not too bad.

We're using the 1971 ANS decay heat standard with an additional 20 percent. It's like the plant's operating at 20 percent more power.

The mixing volume is calculated as a function of time. The higher the steam rate, the slower the growth of the two phase level and a mixture of volume in the vessel.

Now this is not a model assumption, but I just wanted to point out that the source concentrations for this plant are 2600 ppm. And again, the cold leg break is limiting for precipitation.

What you want to do --

DR. BANERJEE: 29.27 percent or what?

DR. WARD: That's at 14.7 -- that assumes the pressure in the upper plenum is 14.7.

DR. BANERJEE: But it must include the boiling point.

DR. WARD: That's the boiling point at 14.7 with boric acid in there.

DR. BANERJEE: So what's the --

DR. WARD: The upper plenum pressure is going to be more -- upper plenum is going to be more like 20 or 25 pounds pressure. So the precipitation limit is not going to be 29. It's probably going to be more like 32/33.

And now our additives in there that will jack it up to about 40 percent. But we're going to assume -- the licensee assumed conservatively 29 percent.

Now hot leg break. I guess I don't need to -- if you have a hot leg break, clearly during the injection phase --

MEMBER WALLIS: Flushes it down.

DR. WARD: You're going to flush this thing fairly quickly because you're going to fill it up. And once the two phase level in the vessel gets above the bottom of the core, it's going to start flushing. AS a matter of fact, it's going to have positive flow through there and I don't think they're going to build that much boron at all. So that's why hot leg breaks are clearly not the thing you want to look at.

Now, if you take that model, and it's the same model that I described last time and it's documented in the Waterford report. So if you want to see the physics of the model, it's pretty simple. It's hydrostatic balance against a loop pressure drop where the drift phrase model calculates a two phase level. And that drift flux model is compared against test data that I've shown you on AP 1000. But it's documented again in that report. So if you want to see anything more on that, you know, feel free and I'd be happy to come over and explain it in some detail.

I want to show you the calculation that I did compared to the Westinghouse calculation. And this is the concentration as a function of time. You can see that the Staff model predicts the Westinghouse calculation, and I used this decay heat, their sump concentration as a function of time which they calculated. Basically used the same assumptions in the calculating a precipitation time, which is within 15 minutes.

DR. BANERJEE: Based on the same volume?

DR. WARD: Based on the same mixing volume. That's half below plenum, that's the core. And only the volume in the upper plenum below the bottom elevation of the core.

Now they could have taken credit for the volume in the upper plenum adjacent to hot leg because the level swells up to there within about an hour, hour and a half and it's going to sit there near the top of the hot leg. So there's an additional 200 cubic feet.

The lower plenum in this plant's about 750 cubic feet. So we're getting about 325 in the lower plenum. Let's see, the core area as I recall is 42 square feet, the height's 12½ feet. So you've got about 400 in the core and another 200 in the upper plenum. And in the hot leg, they've got about another

200 cubic feet, but that's being neglected.

And remember, the steam doesn't carry it away. There's no entrainment. The upper plenum pressure is 14.7. I'm not taking credit for additives. I'm up here if I take credit for the additives. I know we don't like to extrapolate, but gee, we're talking --

MEMBER WALLIS: Ten hours.

DR. WARD: -- 10 hours or more. And they're switching at 6 hours. I guess they're starting at five. I'm sorry. So I mean there's clearly 4 or 5 hours there of margin relative to these.

MEMBER SIEBER: Volume of the core is not the product of the physical dimensions because the core itself occupies about half that space, right?

DR. WARD: That is the free space. That's the free area.

MEMBER SIEBER: That's the --

DR. WARD: That's in between the rods and the --

MEMBER SIEBER: Okay.

DR. WARD: Yes. It was the core flow area. Okay.

That's a conservative calculation. I mean, it's bounding.

Now what I want to do before I talk about boron precip for small breaks, let's talk about the -- yes, blurry. Can you see that okay?

MEMBER SIEBER: Yes. Better than the other one.

DR. WARD: Okay. The old technology works.

When Veronica Klein and I looked at the spectrum, we noticed they only looked at integer break sizes. And if you look 1, 2, 3, 4, 5, 6 inch diameter breaks, you find the area is .0055, .02, .05, .09, .14; there's a pretty wide range there. And typically for small breaks the limiting break is usually in the .05 square foot range, somewhere in here and it's typically a break that's controlled entirely by HPSI flow, which means you find a break size with a system depressurizer and it hangs up just above 600 pounds. The HPSI flow doesn't put as much flow in as an accumulator so it's going to uncover and then slowly recover. And typically that's the worse small break.

For this plant the accumulator comes on during that range. We asked them to do a more detailed spectrum analysis, and you saw that plot. Maybe quarter inch. They went every quarter inch between 2 and 3 and 3 and 4 and found out that breaks between 2 and 3 could be more limiting. The worse break turned out to be a 2.75 inch break compared to the original analysis submittal of 1759. Now this is not one-to-one because I think the 1917 degree F PCT is a time in life study for oxidation. I think the 2½ inch break was worse because although the peak didn't quite get up, it was uncovered longer so the oxidations were like 13.42 percent. But basically what this did looking at a more detail spectrum, better identified the PCT. And when you got these high power uprates, I've seen a plants with a difference of .005 square feet, the PCT can increase by 70, 80 degrees. So when you're getting p around 1900, 2000 if you want to make sure the margin by Appendix K is there, then you need to do this. You need to do a better calculation.

Now we did some calculations. Veronica Klein and I did. Veronica did most of the calculations.

DR. BANERJEE: This is by using your --

DR. WARD: This is RELAP5. No, this was RELAP5. We had a deck. And we got it -- we might have gotten from the licensee and we thank them for that. They have been very cooperative in answering all questions. In trying to understand their model, I've even asked them to do some calculations so I can understand how their model behaves. And they answered everything.

DR. BANERJEE: What is actually run here for the RELAP5? Is it just the core region?

DR. WARD: No. This is the entire system. It's your full blown RELAP5 model, okay. Vessel, each loop. Now we've got 24 cells in here. Better track the two phase level. And also put a hot bundle in there with 24 cells in it with a hot rod in it.

DR. BANERJEE: And this is the low pressure long term --

DR. WARD: No, this is short term. This was for PCT. No, no. The boron precip stuff is --

DR. BANERJEE: But you don't continue this into the low pressure?

DR. WARD: Yes. I ran this all the way out to 8 or 9 hours to show refill. And I'll get to that on the long term part. We ran this for short term to look at PCT. We also ran it to show for small breaks where you can't the pressure down low enough to flush the core, but you can refill the core or resubcool it, reestablish single phase natural circulation and disperse the boron. It was run for that. I'll show you some of those.

DR. BANERJEE: Yes, how does it behave at low pressure?

DR. WARD: Well, great. I mean ask Veronica. I mean, Veronica never came in my office once and said "Damn code bombed again on properties." Never said that once. Run these cases up two hours. We ran .5, .75, 1 all the way up to one square foot. We looked at breaks on the top of the pipe because the lube seals would fill up and potentially depress the core. And we also looked at side breaks. And we found that the most limiting break was between these 2 and 3 inch range. A little different break because they're different critical flow models. But we basically beat it to death.

And we ran these tiny breaks half an inch, 1, 2, 3, 4 out 30,000 seconds.

And running with a .05 second time step, the case runs in two hours.

MEMBER WALLIS: You didn't use TRAC?

DR. WARD: No. I didn't have an input deck for it.

DR. BANERJEE: But I thought this was seamless now, conversion from a RELAP5 deck to TRAC?

DR. WARD: Not quite.

DR. BANERJEE: Little seams still there?

DR. WARD: Yes, there's some bugs in it, you know. The control system you've got to develop. They're not quite the same. You know, the RELAP5 input is a little different, but they're getting there. Not quite there yet.

DR. BANERJEE: Okay.

DR. WARD: They're working feverishly on it.

So I guess I've already said that. So basically we confirmed the worse break, ran it 14 kilowatts per foot, I think it's a little higher at the extended power uprate value. And what I want to do is show you this break between 2 and 3 inches.

And the thing I want to point out is the accumulators. The accumulators are keeping the PCT down below 2000 degrees. And you can see they're coming on here. So the system pressure then rises. They cut back off because it fills the core back up and so there's more energy addition, the pressure goes up. And there's a balance between energy addition and break flow. And so you don't get a huge deluge but it's enough to turn that temperature over. So the accumulators are really controlling PCT here. So if anybody says accumulators are there for large breaks.

No, small breaks. That's why they're there. That's why they're important.

I'm not going to bore you with the results, I just thought I'd show you a PCT plot. And there's 24 cells in the core, so the peak, the peak is in the top four cells. Temperature is around 1900 degrees.

DR. BANERJEE: When do the accumulators kick in that?

DR. WARD: The accumulators kick in right about here and then they deliver enough flow and they turned it over right here. The accumulators are kicking in right about here.

MEMBER WALLIS: That's 5 or 6 hours.

DR. BANERJEE: And what are those two curves?

DR. WARD: Those are two different axial slices. This is cell 22. That's two cells from the top of the core. And this is cell 20. It's 24 cells in that. That's in the hot bundle. So if you want to capture the shape and the void distribution at two phase level, you really need -- I wanted to make sure we had enough detail in there to capture it.

DR. BANERJEE: These are the hottest areas?

DR. WARD: This is the hot bundle. Right. The hottest bundle in the core and the hot rod with the 1400 kilowatts per foot approximately 2 or 3 feet from the top of that core.

Now remember this is Appendix K. This is 20 percent more power than is really there. If we rerun this with 1.0 multiplier, this temperature is going to come down here. It's just like increasing the HPSI flow by 20 percent. That's huge. So it's a pretty big conservatism.

That's probably the conservatism.

And we can skip the next one. It's just another break size and it just shows you the accumulators are controlling PCT here.

I'm only going to mention this quick. If you look at those slides, you'll see a first peak here. There's an early CHF condition. Westinghouse didn't calculate it. I did. It's about 2000 degrees. And I'm not quite sure. We haven't really figured out what's causing it, but my suspicion it's a combination of two things. I'm assuming a reactor trip at the time you get -- I'm assuming a loss of offsite power at the same time you would get a reactor trip on a low pressure during that event. What that does is it says the -- start coasting down and I got about a 2 second delay before rods go in, so I've got two to three seconds before the rods in far enough where I'm generating full power and I'm voiding that hot bundle, very quickly and rapidly, and I get a heat up.

MEMBER WALLIS: And you said Westinghouse didn't calculate them?

DR. WARD: They made the same assumption in their model tripping it at the same time and they're not getting a first peak.

DR. BANERJEE: They used NOTRUMP, right?

DR. WARD: They're using NOTRUMP, I'm using RELAP. Now, I've got a single hot bundle channel with cross flow.

DR. BANERJEE: How far into the transient is this?

DR. WARD: It's right at reactor trip.

MEMBER SIEBER: Two seconds.

DR. WARD: It's two seconds in. Once I get reactor trip --

MEMBER WALLIS: So it still meets the regulation?

DR. WARD: It meets the regulation. The bottom line is it's still below 22. I've never seen a first peak much over 2000. It's usually anywhere from 1400 to 2000 degrees. But I only mention it, you know, we've been talking to each other. We want to get to the heart of it and figure out what -- there's probably differences in the model. It could be input. You know, I'm not sure. But I just wanted to mention it because it's there and however even if we're conservative in the resistance and the way we modeled it, it's still -- the PCT is still less than 2200.

DR. BANERJEE: Your model is a two fluid model whereas theirs in some form is always a mixture model of sorts?

DR. WARD: Yes. It's drip flux approach.

DR. BANERJEE: Yes. So you cannot decouple of the phases which you can?

DR. WARD: Right.

DR. BANERJEE: So they're bound to move --

DR. WARD: Right. Yes.

So anyway, what we'll do, we'll follow up with this. If it looks like we need to pursue this farther, then we will. But I think we probably, we'll be able to resolve this once we have the time to devote to it. More important things were long term cooling, operator actions and behavior.

Now what I'll do is get into the small break. And as I said, small breaks pressure can hang up 1 or 200 pounds for these tiny leaks for long periods of time. And the pressure remains too high and you can't flush. So what do you do? You've got to reduce the pressure to low enough to flush it or cool down early enough and fast enough within your cool down tech spec limit and refill this thing and resubcool it.

And this was an open item identified in the SER, but we're very close to getting closed here. The licensee has done their calculations. I haven't seen them yet, but once I see them and I can see that they've got essentially the same response that I did, then that will be a closed door. But --

MEMBER WALLIS: This comes to the full Committee when it's all going to be sorted out?

DR. WARD: Yes. Yes.

MEMBER WALLIS: Yes?

DR. WARD: Yes, it should.

MEMBER WALLIS: Next week?

CHAIRMAN DENNING: That's next week.

DR. WARD: Yes, it should. They've got the calculations all finished, I just haven't seen them. I just want to -- I have convinced myself that this works. And I'm comfortable with it. I understand it, did the calculations.

MEMBER WALLIS: But it's up to them to

show you.

DR. WARD: But it's up to them to do it and it's up to them to make sure that it works with their model. And they have said that they're getting the same response that I've got for these breaks. It's for the breaks they can't flush, the refilling for the bigger breaks, they're depressurizing and they're flushing the core.

DR. BANERJEE: Tell us the differences that were there before you started to rationalize it. What were you seeing and what were they seeing?

DR. WARD: Well, I wasn't seeing anything from them. I wanted them to do this. There wasn't any analysis of this at all. This was a question I had, hey, you guys got to look at small breaks, too, because you've either got to cool it down and flush it or you got to refill it. And I want to see those calculations. And they did that.

DR. BANERJEE: Okay.

MR. HARTZ: Yes. This is Josh Hartz of Westinghouse.

Dr. Ward did some hand calculations that cast some concern on the depressurization aspects under small break LOCA long term cooling. We have since gone off and done some runs in NOTRUMP space to demonstrate you can get down to a low pressure to the point where you can provide RHR flow to mitigate the boron precipitation here in a timely manner.

And also in speaking for Dr. Ward, he has since done RELAP calculations which basically show the same thing. And we're in the process of validating those calculations and they'll be done within the next few days, the official review of them.

DR. WARD: I'm going to show you the results of a 1, and a 2 and a 3 inch break in the cold leg. And you can boil for a while here.

This is RCS pressure versus time and you can see the smallest break here is the 1 inch break. It hangs up on a pressure plateau. That's because the break is not big enough to depressurize the system. You need heat removal through the generator. So a delta T will develop between the primary and the secondary. You are condensing steam here. You are refluxing. And it's holding the pressure above the secondary side, which is probably around 1100, somewhere, a 1000. At one hour open the atmospheric dump valves, cool this plant down. And cool down. And then at about a little over an hour and a half, maybe just under two hours, you can see this little blip there. And I should have blow this. I apologize.

But what happens here is it refills. And if I plot the void fraction in the core, you will see it go up and it will go to zero right at this time.

Now, if I look at a little bigger break, a 2 inch break --

DR. BANERJEE: Is there any core uncovery during that refluxing?

DR. WARD: Yes. For the 2 inch -- it's in the short term. It's back. It's occurring back -- well, it would occur back in here. Now remember that analysis that you saw for short term doesn't assume any cool down. So if you cool down, you've probably got to limit the amount of uncovery and it's recover fast. So the temperature is probably going to be a little lower.

But we're looking at boron precipitation and getting down here. And the procedure now says cool this plant down at an hour. And so what that does is the one inch refills at about 7,000 seconds. Just under 2 hours.

The 2 inch, and see I stopped it after refill. It refilled right here. So it's a little bigger break, take a little bit longer to refill. But it repressurized and it's resubcooled, void fraction went to zero right here in the core.

And then I said let's run the 3 inch, what happens with that guy. And, of course, he depressurizes a little faster because the break's big enough to -- you get steam out the break and you depressurize real early. But that refills out here around 17,000 seconds. And you can see the void fraction in the core go to zero right about there.

And if I look at a 4 inch or bigger, I'm down below 100 pounds in the real low pressure range where the high pressure pump is going to flush it.

DR. BANERJEE: Then let me ask you something. You get significant periods of concurrent flow here, right?

DR. WARD: Yes, that's right.

DR. BANERJEE: In your opinion how does NOTRUMP calculate concurrent flow?

DR. WARD: Well, it looks at the junction connected from the hot leg to the generator. And it looks at the steam flow going up and it says if the steam flow is greater than a JG that says no liquid goes down, then it doesn't allow liquid to go down. I think the drift velocity model is solved such that if you're in that flooded region, only steam goes up and no liquid will come out.

DR. BANERJEE: Can you get counter

currents.

DR. WARD: Yes, you can. If the steam velocity is low enough, you can have -- for this transfer -- small breaks typically you don't see the water hold up for these 2 and 1 and 2 inch breaks because there's not enough steam flow. You're far out in time. There's a large area there. So there's just not enough of a flux to hold it up.

With these power uprates though, you asked a good question. You're starting to see higher steam rates. And they did see some hold up. And I saw that. We asked them hey, what happens if you don't hold it up, you let it drain out or carry it over. And Josh did some calculations where he let it drain it out.

If you let it drain out, then the core uncovers later and not as deep because it's in a lower decay heat span. Because the code was calculating some water hold up, once the core uncovered, you can see once it got down to about 50 percent, 60 percent uncovery, the steam rate dropped off. The JG was too low and liquid started to drain out. What it did is it recovered the two phase level. But it turned out that the early uncovery, even with that slight recovery, that's still worse than throwing it on the other side or letting it drain out. Because what it does is it throws the uncovery out farther in time when the decay heat is lower, so that's not as limiting.

MR. HARTZ: Yes. Plus there was a little bit of a extended period of two phase low quality mixture coming out the break in the cold leg there, which tended to drive mass loss up.

DR. WARD: Okay.

DR. BANERJEE: And RELAP5 isn't great at this flooding calculation either. Because, you know, the problem -- we can discuss it off line.

DR. WARD: Okay.

DR. BANERJEE: But it's long known that the interfacial drag correlation has difficulties in this region.

DR. WARD: Yes. Could be.

DR. BANERJEE: Way back --

DR. WARD: Yes.

So what this really says is it really emphasizes operator action. I mean to control boric acid you have to cool -- in order for this refill to occur, you have to initiate a cool down at an hour. And the licensee has agreed to emphasize or make sure that it says start your cool down no later than an hour. Because it's important to depressurize and get the pressure down and flush it as early as -- you don't want to sit there boiling for long period of time because if you did, let's say a dump valve failed -- and that analysis I did I'm going to point out there are four dump valves. I failed one of them and I failed the HPSI part; that's a multiple failure event and it still worked.

What this says is that they need to be very aware of there are other depressurization capabilities. And they have to PORVs as a backup. Plus four dump valves. There's one on each generator and then there's a common one on the main steamline for both units. And they're a huge capacity.

So really what this says is the EOP guidance is really important and the equipment you use to cool down. And make sure that you can control boric acid for small breaks is important. And all they need to know is when the break opened and they switched to simultaneous injection at 6 hours, that's all they need to know about. But they need for small breaks to be successful, you need to cool down no later than an hour. If you're going to wait longer then -- the scenario is going to change. The other thing is you don't also caution -- there's going to be a caution in there, I think this is part of their training program. And if your boiling for extended period of time, let's say you're out eight to ten hours. And since the pressure in those cases is up pretty high, the precipitation limit is up like 50 percent. So the 6 hour doesn't apply. I can sit there and boil for a while. But you don't want to do that because if you get power back, you don't want the operators crashing the pressure down when you've got 40 weight percent in the system. So it's important to cool down and get this thing refilled and flushed as early as possible.

And the calculations show that you can do that. Even with a multiple failure event you can do it. At least I'm convinced of it. And I think Josh and Westinghouse has done the calculations to also show that.

So the EOP, this review had done a couple of things. It's identified a worse break. We got rid of the integer break spectrum.

They were assuming all the loop blown. Now that's not their approved model. Had them rerun it again with only assuming the broken loop seal clears, and that's what we approved. And they did in order to compensate for the very high PCTs. Probably PCTs over 2200, they increased the accumulator pressure to 625 to keep it down around 1900. So from a safety standpoint, that's a good thing to do. Now they'd already increased the HPSI flow 5 percent. That's also from a safety standpoint a good thing to do.

But then the Staff calculations on boric acid precipitation for small breaks also enabled us to emphasize the need for the EOPs and have the operators cool this thing down no later than an hour and be very sensitive to the depressurization equipment that they have. And not to inadvertently depressurize the system if you for some reason boil for 8 to 10 hours. And even if you're up there around 100 pounds to 200 pounds pressure, boiling for 10 or 15 hours, it's in solution. You've got 55 weight percent for probably a limit. But your accumulating too much boil. You don't want to sit there too long. The emphasis is get the thing down and get it refilled.

CHAIRMAN DENNING: I'm missing as far as whether you made recommendations for EOP actions that haven't really been implemented yet relative to this timing of cool down?

DR. WARD: Right. The vendor needs to EOP guidance that's consistent with their analyses that shows in order to refill the system for these small breaks, you need to initiate a cool down no later than an hour. Don't boil for long periods of time because you can get --

CHAIRMAN DENNING: You say "initiate a cool down." Where do you have to be when?

DR. WARD: Well, you start -- remember I showed you the calculation. Right here. One hour.

This analysis, the refill for these breaks and you flush this. It's based on cooling down at one hour. If you come out here, I mean you're going to be boiling for a longer time, you're going to build up more boron. It's probably not a good thing to sit there boiling for a long time building up a lot of boron because you put yourself in a situation where if you get power back out here and then you decide to open the turbine bypass and crash -- let's say you could crash the pressure down, you could cause a precipitation. You don't want that to happen.

You want to cool it down. Start the cool down early and get it refilled and disperse the boron so you don't have these large amounts of boron in the system.

MR. HARTZ: This Josh Hartz from Westinghouse again.

The way the EOP guidance is currently written this would occur. In fact, it would occur sooner than that. What Len's analysis is showing that if you start to cool down at one hour, the boron precipitation concern as analyzed here really isn't a concern.

Estimates from the Operations folks show that this cool down would actually start somewhere between 30 to 40 minutes into the transient. And that's the way the guidance is currently.

And Pete with his Operations experience can maybe add something to this.

MR. SENA: Yes. This is Pete Sena.We ran the Operations crews both units through simulated small break scenarios, various spectrums of small breaks, using existing EOP guidelines. And the crews were able to initiate the cool down with the existing network within 30 minutes.

I personally ran it and with one signal operator, assuming one operator was incapacitated. And the cool down was initiated within 24 minutes.

So with existing guidelines we can satisfy the one hour requirement that Len has identified.

DR. WARD: A couple of other things here, too, I'd just like to add.

There's some other depressurization mechanisms that we didn't even account for. And one would be using pressurization ox spray if the power operator relief valves on the pressurizer were not available. We did not credit that.

And also for these smaller breaks which don't depressurize, like I discussed earlier you do go through a single and two phase natural circulation period. Typically for these breaks that's on the order of anywhere from 1,000 to 2,000 seconds. During that time frame everything within the reactor coolant system is homogenous. And so these boil off calculations would really start after that mechanism breaks down.

We assume that that starts at time equal zero. And so if the calculations has truly took that into account, the actual hot leg switchover time would be extended well beyond what is being calculated here, not accounting for that.

DR. BANERJEE: But the RELAP5 calculations automatically should take natural circulation and break down of natural circulation into account.

DR. WARD: They did. They did. They have that in there. That's built it. That's built it.

DR. BANERJEE: So I mean that's automatically taken --

MR. LASH: Yes, it's in there.

DR. BANERJEE: --into account then.

DR. WARD: Right. You're right. That's correct.

MR. HARTZ:

Well, they do for the depressurization aspects, but for the boric acid precipitation calculations they do not because it's a different model.

DR. WARD: Yes, that's a different model.

DR. BANERJEE: But you could incorporate boric acid into your -- as a scale of field, right?

DR. WARD: You could. And then you get diffusion problems. You know, you got to make sure that -- all over these cells.

DR. BANERJEE: Because of your --

DR. WARD: Because of the first order -- difference on the --

DR. BANERJEE: On the cells.

DR. WARD: You know, so I got to go through and got to do a third order and then I got to a put -- boy, that's a pain in the you know what.

DR. BANERJEE: Yes. So the scale equation would have to be solved --

DR. WARD: That's right. That's right. Right.

CHAIRMAN DENNING: You done?

DR. WARD: Yes, I'm done. So I guess I

don't -- unless you have any questions.

CHAIRMAN DENNING: Thank you.

DR. WARD: Looks fine.

DR. BANERJEE: You do that in any case, you know.

DR. WARD: Yes.

DR. BANERJEE: You could with a lot of these issues?

DR. WARD: I could, yes.

DR. BANERJEE: It's not such a big deal.

CHAIRMAN DENNING: And now we're going to have a discussion of containment from NRR.

To the extent that there is some repetition, go quickly.

MR. LOBEL: Yes, there's a lot of repetition.

Good afternoon. My name is Richard Lobel. I'm a senior reactor systems engineering in the Office of Nuclear Reactor Regulation. I'm here today to discuss the Staff review of the FENOC proposal to convert the Beaver Valley Unit 1 and Unit 2 containments from sub-atmospheric to atmospheric containment designs.

The licensee performed the analyses to support the containment conversion at extend power uprate conditions. So the Staff's review of their containment conversion also serves as the review of the extended power uprate.

A lot of what I was going to say has already been discussed, so I'll try to go through it or skip parts of it.

Next. Okay.

February 6, 2006 there was an NRC letter to FENOC that approved the conversion of the Beaver Valley Unit 1 and Unit 2 containments from sub-atmospheric to atmospheric. And as part of that proposal, part of the original proposal the licensee included consideration of extended power uprate and the Unit 1 steam generator replacement. Also the licensee used the new analysis method, MAAP-DBA.

Next slide.

Beaver Valley units aren't the first power plants to convert from a sub-atmospheric to an atmospheric containment. Millstone Unit 3 is a 4 loop Westinghouse designed reactor that was originally licensed as a sub-atmospheric containment in 1986 and in 1990 the licensee for Millstone proposed converting from a sub-atmospheric containment to a higher pressure but still with a vacuum, but the design basis was changed to that of an atmospheric containment, which is pretty much what Beaver Valley has done. And the staff approved the Millstone Unit 3 proposal in January of 1991.

I think I'll skip this one. The licensee already talked about the pressure ranges, that they're increasing the pressure in the containment but it'll still be operated from 12.8 psia to a very slight vacuum. The licensee added a lower temperature limit in the tech specs also that limits the mass of air in the containment for a given pressure that's important for the pressurization calculations.

Next slide. Let me just say that this is the sub-atmospheric containment design bases which were the design bases for the Beaver Valley containments before the conversion. And the design bases that are italicized are the ones that changed.

For sub-atmospheric containment the requirement is to depressurize after a LOCA in one hour and once depressurized to stay sub-atmospheric for the rest of the accident. And that has a direct impact on the dose calculations once the reactor is depressurized again, they don't have to assume leakage from the containment for dose calculations.

For the atmospheric containment design, the other design bases remained the same, but the ones of concern, the sub-atmospheric containment, were replaced by one that says that the containment pressure should be less than 50 percent of the peak within 24 hours. And the reason for that is that helps in the dose calculations because when the pressure is less than 50 percent, the guidance for dose calculations states that the containment leakage can be reduced by half after 24 hours.

CHAIRMAN DENNING: What do you mean "minimum containment pressure greater than 8 psia." It's just at that initial time when they need credit?

MR. LOBEL: For the atmospheric containment -- no, they calculate a peak pressure and then they demonstrate that within 24 hours the pressure is reduced to 50 percent of that peak pressure.

CHAIRMAN DENNING: Your fifth bullet right there.

MR. LOBEL: Oh, that's really a requirement for reverse pressure on the containment that the pressure on the outside of the containment could be larger than the pressure inside the containment. And --

MEMBER WALLIS: Is it collapsing the containment you're worried about?

MR. LOBEL: Yes. And there's a structural requirement for that. And that's demonstrated by assuming an inadvertent actuation of the containment sprays and that the pressure won't go down below 8 psia.

CHAIRMAN DENNING: But clearly you'd have to lose an awful lot of air for that to happen in this containment?

MR. LOBEL: Well, you start with a low pressure and then you make very conservative assumptions about the temperature of the sprays and that kind of thing.

CHAIRMAN DENNING: Okay.

MR. LOBEL: It's a very conservative hand calculation.

The large break LOCA I think you've pretty much gone through, or the licensee pretty much went through with that. Let me just say that the calculations for the mass and energy release were done with NRC approved Westinghouse methods for less than one hour. For greater than one hour the mass release was calculated with the same NRC approved Westinghouse methods. The energy was calculated with the MAAP-DBA code.

We had some questions about separating the calculation of the mass and the energy between two separate codes. So Veronica Klein, who is still here, did some calculations for us with the RELAP code that essentially verified that we got almost the same results the licensee did with separating the two calculations. And so we found that their approach was satisfactory.

You've already seen the LOCA results. I won't go through that again.

For the main steamline break, the mass and energy release calculations were done with Westinghouse approved methods. The licensee modeled the replacement steam generators, the cavitating venturies. Since it's difficult to tell what size break and what power level they're limiting for main steamline break, the licensee did a spectrum of breaks and power levels. And made conservative assumptions, the -- failure and other conditions that maximize the inventory in the steam generator and the stored energy in the steam generator.

One of the important parameters from the main steamline break calculation is the liner temperature. The LOCA gives the peak containment pressure, the main steamline break is the highest temperature. The acceptance criterion for the containment liner was 280 degree. And the licensee calculated temperatures lower than that with conservative assumptions. For instance, the heat transfer coefficient between the containment atmosphere and the liner was multiplied by a factor of 4 that's consistent with the Standard Review Plan.

Now for over pressure and NPSH. The Standard Review Plan Section 6.2.2 for sub-atmospheric containment allows credit for containment accident pressure for available NPSH during the injection phase of the LOCA. At the pre EPU power level for the sub-atmospheric containment Beaver Valley Unit 1 credits containment accident pressure calculating the available NPSH for the recirculation spray pumps and the low head injection pumps. And this was part of the original licensing bases.

At the pre-EPI power level in the sub-atmospheric containment Unit 2 doesn't credit containment accident pressure. At the extended power uprate conditions conversion on the atmospheric containment, the containment accident pressure is credited for Unit 1 for the recirculation spray pumps not for the low head safety injection pumps. That's based on changing the timing of the actuation of the low head safety injection pumps.

Unit 2 at extended power uprate with the containment conversion still doesn't need credit for containment accident pressure.

Let me see. I think they went through the basic reasons. Basically for Unit 1 the recirculation spray pumps start at a time when the level in the sump is still relatively low and the temperature of the sump water is relatively high and due to the placement of the pumps in Beaver Valley 1, that's what requires credit for containment pressure. And we queried the licensee about what would happen if you did a realistic calculation and not a conservative calculation. And they say that due to those factors they would still need credit for containment accident pressure.

CHAIRMAN DENNING: I wasn't sure I heard that earlier. Is that basically the position of Beaver Valley that for realistic calculation with uncertainties, not suggesting that you would do that, but is that your feeling that -- did you hear that fifth bullet?

MR. LOBEL: We asked that question in a formal RAI.

CHAIRMAN DENNING: In a RAI. So it get a formal answer.

MR. FREDERICK: Ken Frederick.

In looking at a better estimate analysis the parameters that we can vary towards more best estimate do not directly impact the sump temperature to a degree where we could get rid of the requirement for containment over pressure. There is some benefit there, but it's not enough to get rid of the requirement.

CHAIRMAN DENNING: Thank you.

MR. LOBEL: Next.

This is similar to the curve that was shown before, and it's a curve for the worst case of the containment pressure actually in terms of overpressure versus the pressure that's required for adequate NPSH for the inside and outside recirculation spray pumps.

Again, this is in terms of overpressure so you're looking at their definition of overpressure which is the calculated containment pressure above the initial containment pressure.

And you can see that this is for the first case, that they don't need the credit for a very long time and there is margin to a conservatively calculated containment pressure.

The difference between the peak pressure in this case and the minimum pressure is really less than it was last time I was here talking about Vermont Yankee. There was a lot larger difference. But the licensee submittal was very good with respect to talking about the input parameters that went into this and sensitivity studies they did. And there's a table in the Jun 2, 2004 letter, it's table 4.3 where they have a list of the significant variables and sensitivities that they've determined for the different cases and for NPSH they assumed values that were in the most adverse direction for calculating NPSH.

So judging from that, we're convinced that the calculation is conservative for a minimum pressure.

The next curve you've also seen before, and I think that had a pretty good explanation so I won't go through that again. But, again, I think the important point is in terms of containment integrity. For the largest assumed hole between the inside and the outside of containment, the largest penetration that connects the inside atmosphere to the outside atmosphere if I assume that that's open, I still maintain some NPSH margin.

Next slide.

There is a 1977 report which was submitted to the NRC where there was some testing of a recirculation spray pump for North Anna Unit 2. You saw the NPSH curves for it before. And the central point, again, was that this pump was tested in cavitation at different levels and then run for half an hour at a significant amount of cavitation well below the 3 percent usual required NPSH value. And there was essentially no wear and no damage to the pump.

So in conclusion for this part, the Staff accepted the licensee's proposed credit for containment accident pressure in defining available NPSH for the recirculation spray pumps based on several reasons.

First, containment integrity is assumed for postulated designed bases accident, in particular as I've said before here, Appendix K permits the use of conservatively minimized containment pressure in determining peak cladding temperature and oxidation limits. And also offsite and control room dose calculations assumed containment leakage at -- which is a very large leakage value of containment that's specified in the technical specifications. And that low leakage rate also assumes containment integrity.

Furthermore, the licensee's study shows, as I just said, that for the largest penetration directly connecting the inside of containment to the outside of containment, that there would still be sufficient NPSH margin.

The Beaver Valley containment pressure during normal operation would be slightly sub-atmospheric. That's a tech spec requirement. And therefore, any significant leakage in containment should be detected.

Also credit for containment accident pressure is applied for a relatively short time in the case of Beaver Valley. And as I just said, also the Beaver Valley pump tests that demonstrated that the pumps can operate with some level of cavitation for a longer time than they would need to according to these conservative calculations without experiencing any damage or wear.

And finally, there's no impact on the emergency operating procedures of crediting containment accident pressure.

MEMBER MAYNARD: I would agree with a caveat that containment operating at a vacuum doesn't always guarantee that there's no leak path when it's pressurized. But I do agree with the overall conclusion.

MR. LOBEL: It's sort of like the argument that I was making for Vermont Yankee, which was an inerted containment. That it's just another factor.

MEMBER MAYNARD: Yes.

MR. LOBEL: And it depends on the size of the hole.

MEMBER MAYNARD: And the characteristic. A check valve will stop flow one way but not another way.

MR. LOBEL: Right.

MEMBER MAYNARD: A minor thing.

MR. LOBEL: Right.

MEMBER MAYNARD: Not a direct correlation.

MR. LOBEL: I think part of this review was actually the review of the MAAP-DBA code. The licensee actually made a presentation to ACRS to the Thermal-Hydraulic Phenomena Subcommittee back in November of 2001. And since then the Staff and the licensee have had an interaction talking about the various proposed models in the code. The licensee submitted a description of MAAP-DBA in November of 2003 in a letter to the NRC. And there's another description of the code in the licensee's containment conversion submittal.

MEMBER WALLIS: When we saw, we had a lot of questions, didn't we?

MR. LOBEL: Right. There --

MEMBER WALLIS: We were expecting to see it again.

MR. LOBEL: There was some good questions that were asked. That version was called MAAP5. And the licensee revised the code based on the review that we did to MAAP-DBA where MAAP-DBA is more in line with the Standard Review Plan. MAAP5 had a lot of -- not a lot. Had some moderates that were kind of unique to containment analysis at the time. And as we went through the review process, we ended up with MAAP-DBA.

I really have a longer presentation on MAAP-DBA, but given the time constraints, I wasn't going to do very much. Of course, if you'd like to see more. I can't speak for the licensee, but we can come back, the Staff can come back and talk about it in more detail.

DR. BANERJEE: Can I just ask a couple of things about it.

MR. LOBEL: Sure.

DR. BANERJEE: Do you have some experiments against which it's been validated?

MR. LOBEL: Yes.

DR. BANERJEE: That's one.

MR. LOBEL: Separate tests and integral containment experiments.

DR. BANERJEE: And any other codes against which it has been compared?

MR. LOBEL: The licensee made comparisons and got pretty close agreement with GOTHIC6. GOTHIC is kind of getting to be kind of the industry standard for CONTAIN code. Are you familiar with GOTHIC at all? GOTHIC was developed by EPRI.

DR. BANERJEE: Yes.

MR. LOBEL: Developed for EPRI by Numerical Occupations, Incorporated. And it's an Appendix B code. It's subject to Part 23. And EPRI for ever new version that makes a significant version, basically the whole validation process in a lot more detail than vendors usually do for these kinds of things. They compare with a lot more data.

Most of the data that Beaver Valley used for the MAAP code was International Standard Problems. There's a German decommissioned reactor, HDR, that had a couple of standard problems. And some very old data that's still useful from a decommissioned reactor and the reactor in this country, CVTR that they compared with. And the comparisons were good.

DR. BANERJEE: This is the spray and all this sort of stuff?

MR. LOBEL: Right. With spray and without spray. There are some separate effects tests that were done with some Canadian data where there is, I believe, one nozzle on a five nozzle spray test in a steel vessel. But the first test was without the spray. So the licensee compared with the data without the spray and with the one nozzle and the five nozzles.

And also for some Japanese data, they did comparisons against data -- I'm trying to remember now if they did -- the Japanese tests were done with a single nozzle and with multiple nozzles. And the advantage of the single nozzle test was that the spray didn't touch the walls of the vessels. So it was strictly an interaction of the spray with the atmosphere without the effects of the walls and condensation and impacted the spray --

DR. BANERJEE: Has the NRC Staff had a chance to use this code and compare it with some experiment which it hasn't been validated against?

MR. LOBEL: Use the MAAP code? No. No, we haven't.

DR. BANERJEE: You don't have access to it to compare it with anything?

MR. LOBEL: Really didn't ask for access to it.

DR. BANERJEE: Okay. In other words, I'm always sort of worried that codes can be validated against data but once they're frozen and you compare them to a new set of data, they may not work so well.

MR. LOBEL: Well, back in the days when we were reviewing MAAP5 we did pretty extensive calculations to compare with MAAP5 using our CONTAIN code. We didn't use the MAAP code, but we used the CONTAIN code. And our Office of Research was involve din that review. And at a certain point in that review we decided when the licensee came in with MAAP-DBA, we decided that based on the changes that were made from MAAP5 to MAAP-DBA, that MAAP-DBA pretty closely followed the Standard Review Plan, the Tagami Uchida correlations and the same type of heat transfer correlations that are used in the CONTAIN code. And we made the decision that we didn't need to do anymore audit calculations.

DR. BANERJEE: Do you have any code available to you to do an independent audit?

MR. LOBEL: We have the CONTAIN code. Like I say, we used the CONTAIN code for the MAAP5 review.

We also have the GOTHIC code. We have--

DR. BANERJEE: GOTHIC6?

MR. LOBEL: Well, GOTHIC6 is what the licensee compared with. We have GOTHIC7.2, which is a later version. The latest version, I believe. So we have that code available to us also.

CHAIRMAN DENNING: To what extent is this operated in a best estimate versus a licensing kind of mode, isn't it? Don't you typically use it in a mode in which, depending upon whether you're looking for high containment pressure or low containment pressure and stuff like that, it's --

MR. LOBEL: Are you talking about MAAP?

CHAIRMAN DENNING: MAAP-DBA, the way it's used.

MR. LOBEL: A lot of the conservatism I think comes from the assumptions that are made, the input that's made. So you --

CHAIRMAN DENNING: Like Tagami Uchida I've always thought that those were very conservative correlations.

MR. LOBEL: Yes. Yes, they are. There's some disagreement about how conservative in comparing the data. But the Staff has always accepted those on the basis that they're conservative.

MEMBER WALLIS: They're conservative in what way?

CHAIRMAN DENNING: Node.

MR. LOBEL: But-- but -- but MAAP has other heat transfer correlations that they use. For MAAP, MAAP is used for single node and multiple node calculations. For the single node calculations which they used for the peak pressure and temperature and those things, they're done, it's Tagami and Uchida because the basis of deriving Tagami and Uchida was a single volume experiment. For the multiple node different heat transfer correlations are used that are more best estimate.

But then like I was showing for the case of the liner temperature, you know you can bias the results to either give a high heat transfer, a low heat transfer, high pressure, low pressure.

DR. BANERJEE: Perhaps the concern is that this core is being used in sort of an inverse way. Usually you are trying to be conservative with regard to how high the pressure is. I mean, most coded are tuned to do that. Now you're trying to be conservative with regard to how low the pressure can be.

MR. LOBEL: It's really just a function of the input. For instance, if I'm trying to predict a low pressure, I --

DR. BANERJEE: Lower limit?

MR. LOBEL: Lower limit.

DR. BANERJEE: Yes.

MR. LOBEL: Lower limit, a lower bound on the pressure, I'll assume that the containment starting pressure is low. If I were doing a peak pressure calculation, I would assume that the starting pressure is high.

MEMBER WALLIS: But how about the heat transfer coefficients?

MR. LOBEL: The heat transfer coefficients--

MEMBER WALLIS: Are they conservative one way or the other way?

MR. LOBEL: Right. Right. That would be another one.

MEMBER WALLIS: Which way are they?

MR. LOBEL: Well, for peak pressure --

MEMBER WALLIS: You'd use those?

MR. LOBEL: -- you would want to minimize the --

MEMBER WALLIS: Right.

MR. LOBEL: -- heat transfer. They say like for the peak pressure you want to minimize the heat transfer coefficient.

MEMBER WALLIS: Right.

MR. LOBEL: For the minimum pressure you try to maximize.

MEMBER WALLIS: Well how do you do that?

MR. LOBEL: How do you do that? Well, you can do it in several ways. You can minimize the heat transfer --

MEMBER WALLIS: You can make it zero. You can make the heat transfer coefficient zero.

MR. LOBEL: You could --

DR. BANERJEE: You could not do it in infinity --

MR. LOBEL: That's what the BWRs do.

MEMBER WALLIS: Right.

MR. LOBEL: They look at zero.

DR. BANERJEE: But you can't make infinity?

MR. LOBEL: Well, I --

DR. BANERJEE: Or can you?

MR. LOBEL: I haven't done the calculations, but I imagine there's probably a point of diminishing returns where it doesn't matter anymore.

DR. BANERJEE: Well, if the energy goes

through --

MR. LOBEL: Perhaps others can elaborate.

DR. BANERJEE: -- the containment. I mean, is it the conduction losses of --

MR. LOBEL: But that's pretty minimal the time we're talking about. The containment is a pretty stiff concrete structure. That's not a major concern.

DR. BANERJEE: So if it soaks up all the heat, the containment, then what happens?

MEMBER WALLIS: Limited by conduction into the wall.

DR. BANERJEE: Yes. Is the conduction limited then or is it convection limited, the heat transfer?

MR. LOBEL: Are we talking about peak or minimum or --

DR. BANERJEE: We're trying to establish a minimum pressure curve.

MR. LOBEL: Okay.

DR. BANERJEE: So if heat is now conducted into the wall of the containment --

MR. LOBEL: Right.

DR. BANERJEE: -- and we assume the containment is extremely well mixed, then the only resistance would be the conduction heat transfer. We can do a hand calculation, correct?

MR. LOBEL: Well, the big impact isn't the conduction into the containment. It would be the sprays. And especially --

DR. BANERJEE: Well, you turn that off, that heat transfer to get a minimum, right? Or is that--

MR. LOBEL: To get a minimum pressure? No, that's how --

DR. BANERJEE: Sorry. You want it all into the spray?

MR. LOBEL: Right. Right. The Standard Review Plan says for the LOCA analysis where you calculate a minimum pressure that all systems that can reduce the pressure have to be assumed to be operating and --

MEMBER WALLIS: To spray, the pumps have to work, so these --

MR. LOBEL: Fan coolers, containment sprays, maximizing the heat transfer to the structures.

DR. BANERJEE: Right. One would have to look through this and write down all the assumptions--

MEMBER WALLIS: That's what they did?

MR. LOBEL: Yes. Yes.

MR. FREDERICK: This is Ken Frederick.

MR. LOBEL: And that's in the table 4.3 that I was referring to before. If you want to look at that, But that lists two pages, that list of variables.

DR. BANERJEE: So if you now compare the code with the data, it always under predicts the data then?

MR. LOBEL: Well, when they do the --

DR. BANERJEE: It has to.

MR. LOBEL: -- calculations for data, they're trying to do a best estimate calculation because presumably that's what the data is. It's the best estimate.

DR. BANERJEE: But if you make corresponding assumptions that you did for these calculations with the data --

MR. LOBEL: If I made -- well, there are some studies that were done by the Staff. The Office of Research published some reports. We in NRR asked Research to look at the CONTAIN code and make some recommendations of how to use the CONTAIN code as a design bases code. And they went through and did sort of what you're talking about in those reports. They compared with data and then they made different assumptions to show that they would be above or below the data or how it impacted comparisons for the data. And I can give you those references, if you want.

DR. BANERJEE: So there is a set of comparisons with CONTAIN at least --

MR. LOBEL: Right. Right.

DR. BANERJEE: -- with the data where they always under predict the data given a certain set of assumptions?

MR. LOBEL: Well, I don't want to over sell it. I think I want to stick with what I said that just they compared with data and then did some sensitivities to see how different parameters effected the results. They weren't trying to do -- you know, minimize, get a lower bound compared to the data. But it's done primarily with codes like GOTHIC and MAAP and even CONTAIN is the assumptions you make on the input more than the models that are in the code itself.

MR. FREDERICK: I just want to add something here. This is Ken Frederick.

In terms of the multiple node analyzes which we were using for NPSH and over pressure calculations, that typically uses a natural convection coefficient. And as part of our sensitivity studies we did multiples by that. WE increased it by a factor of 4 or 5. And we don't see a whole lot of change based on that.

And one thing that becomes limiting for most of the heat sinks is conduction through paint and coatings actually become more limiting than the convection on the surface. So that's why it doesn't have a dramatic impact on the results.

DR. BANERJEE: So the limiting phenomena are conduction to structures in terms of --

MR. FREDERICK: For structures that are painted, yes.

DR. BANERJEE: So the --

MR. LOBEL: No. I think you have to understand what he was saying. For the structures, the paint is limiting.

DR. BANERJEE: Yes.

MR. LOBEL: But in terms of what minimizes the pressure, I don't think you would say it's the structure.

MR. FREDERICK: No. It's been effected by the heat transfer coefficient to a degree.

MR. LOBEL: Yes.

MR. FREDERICK: But you reach a point where it doesn't make any difference because conduction becomes limiting.

MEMBER WALLIS: So the sprays dominant in this circle, where if they work it means the pumps working and therefore everything is okay. So it's, you know, a self-correcting situation.

MR. FREDERICK: Right.

MEMBER WALLIS: That probably dominates everything.

DR. BANERJEE: Does the spray dominate everything?

MR. FREDERICK: Yes. Once the sprays come on, the heat transfer to the structures is relative unimportant because the sprays control the pressure.

MR. LOBEL: Especially for a plant like Beaver Valley that was sub-atmospheric, but there is sub-atmospheric containment because first of all there are three spray systems or two spray systems, depending on how you look at it. There is a quench spray system which is taking section from the RWST which for a sub-atmospheric containment is cooled. So it's not at assumed 90 degrees or a 100 degrees or whatever. It's down around 45 to 55 degrees for the quench spray.

And then there's the recirculation spray.

So you're putting an awful lot of water

into the containment atmosphere to lower the pressure because that's the way they were designed. They had to get down below atmospheric pressure in an hour. And that's the main way that was done with all the spray water into the containment.

So you have cooled spray water from one spray system and then two other spray systems that are spraying into containment.

DR. BANERJEE: Yes. I suppose the system is self-correcting, as Graham says. But leaving that aside for the moment, the voracity of MAAP-DBA with regard to establishing a lower pressure bound for the system, which is what we're looking for as opposed to an upper pressure bound which most of these codes are usually tuned to do, is sort of an issue which maybe you could just --

MEMBER WALLIS: Well, you're writing --

DR. BANERJEE: Yes, write a note or something which sort of establishes why we think that it's --

MEMBER WALLIS: You're writing new guidance on this whole issue, aren't you?

MR. LOBEL: In the Reg. Guide, yes.

MEMBER WALLIS: Can you come back to us with some of this other technical data, too, at that time?

MR. LOBEL: Sure.

MR. LOBEL: But I think the important point is that these newer codes, GOTHIC, CONTAIN which isn't a new code anymore, MAAP-DBA don't try to buy us things one way or another with the code itself as much as with the input data. So that gives the code more flexibility. I can use the same code to calculate peak pressure and minimum pressure. I just change the bias on the input, not the code itself.

DR. BANERJEE: Well, you'd have to demonstrate that that, that is true in some way.

MR. LOBEL: Well, I think if you look at this table, 4.3 in Attachment 1 to the June 2, 2004 report, the licensee did a pretty good job of listing the biases and a lot of variables for the NPSH calculation and for the peak pressure calculation, and for some of the other calculations. So if you go through that you can see how things were biased to get a certain result.

DR. BANERJEE: Sure. But that's a sort of a sensitivity study. But what would be, perhaps, more convincing would be in this note to compare it with data where you actually do the similar sort of thing. You bias the input. And show that you under predict the data or over predict it. And that would be convincing that the same methodology applies to data. I mean, if it applies to itself, you're just doing a sensitive study. We don't know about the voracity of the code at this point.

MR. LOBEL: No. Are you asking the licensee to do that --

DR. BANERJEE: No, no, no.

MR. LOBEL: -- or are you asking the Staff to do it without a code or --

DR. BANERJEE: I don't know. In this note where you're establishing guidance, perhaps --

MR. LOBEL: Then it's the Reg. Guide that you've been talking about.

DR. BANERJEE: Yes.

MR. LOBEL: I think that's what we're talking about.

DR. BANERJEE: The supporting data or whatever for a methodology would be to show that a sensitivity study on a code somehow done on a scenario related to a reactor is equivalent or is supported by some sort of sensitivity study done on data which establishes that this type of variation of input parameters truly establishes a lower or upper bound. I mean, the only thing we know is data at the end;

nothing else.

MEMBER WALLIS: It's usually not up to the licensee, though --

DR. BANERJEE: Yes. Well, but it is.

MEMBER WALLIS: -- and the NRC will approve a code based on comparison of the data, then it gets used.

DR. BANERJEE: And if this is methodology is established that, yes, we can vary the input parameters and this will give us a lower bound because I've compared it with all this data, we're sure of it, then we --

MEMBER WALLIS: Well there's been a guide which says you can do uncertainty analysis, so --

DR. BANERJEE: Somewhere here.

CHAIRMAN DENNING: Actually, I don't thin that -- I think really, Sanjoy, the way to do it is to validate your code realistically against data.

MEMBER WALLIS: Right.

CHAIRMAN DENNING: Once you have a code that you believe, then it's not that hard to play the games of changing the parameters --

MEMBER WALLIS: Right.

DR. BANERJEE: Yes.

CHAIRMAN DENNING: -- to under estimate or over estimate.

MEMBER WALLIS: The way to do it.

DR. BANERJEE: All right. If you can assume an uncertainty at this time --

MEMBER WALLIS: Right. Right.

CHAIRMAN DENNING: But let's move on now because I think we've spent enough time on this for the moment, I mean other than your conclusions here.

MR. LOBEL: I can go to my conclusion. Can we go to the conclusion, the last slide. Okay.

The Staff has issued the SER approving the conversion from sub-atmospheric to atmospheric containments for Unit 1 and Unit 2.

And also approving MAAP-DBA as part of the same review.

CHAIRMAN DENNING: Actually, go back one slide to the validation slide. Because we ought to at least look at that since that's kind of the focus of this discussion you had there.

MR. LOBEL: Okay. There was a comparison with GOTHIC6. There was a comparison for the mass and energy release for small break with the NOTRUMP code. We did some calculations comparing MAAP-DBA for greater than one hour with RELAP. Those were the code comparisons.

Like I say, for a previous review where it was a MAAP5 code, I think we did quite a lot of comparisons with --

MEMBER WALLIS: RELAP can model the containment?

MR. LOBEL: I'm sorry, what?

MEMBER WALLIS: Can RELAP model the containment?

MR. LOBEL: No. In that case we were doing mass and energy release calculations.

MEMBER WALLIS: Oh, I see. Okay.

MR. LOBEL: And for the NOTRUMP calculations that was comparing MAAP-DBA to NOTRUMP for mass and energy release calculations.

There were separate effects tests were done, condensation and spray tests. And then the integral test I talked about. The Canadian spray test, Japanese spray tests. There was the CVTR which stimulated a steamline break without sprays and with sprays. There is the HDR, which is a German reactor which doesn't look anything like a U.S. reactor, but there are international standard problems from that that the license compared with. And all those comparisons were pretty good.

CHAIRMAN DENNING: Thank you. And you're

done then?

MR. LOBEL: Pardon?

CHAIRMAN DENNING: You're done now?

MR. LOBEL: I'm done.

CHAIRMAN DENNING: Thank you very much.

Okay. Now we're going to hear about source terms and radiological consequences. And this is another presentation I think can really be pretty brief.

MEMBER WALLIS: Yes, let's move it along.

CHAIRMAN DENNING: Let's try to move quickly.

MEMBER WALLIS: Well, must give us some presentation and we'll listen.

MR. PARILLO: Good afternoon. My name is John Parillo. I'm a health physicist with the Accident Dose Branch in the Office of Nuclear Reactor Regulation. I'm here to --

CHAIRMAN DENNING: Mr. Parillo, speak into the microphone.

MR. PARILLO: All right.

Good afternoon. My name is John Parillo. I'm a health physicist in the Accident Dose Branch, and I'm here to discuss the source terms and radiological consequences analyses.

The first part of the discussion refers to the source terms for input into radwaste management systems. So basically how does the EPU effect the normal operations. This is covered in EPU Section 2.9.1 of the SE.

Basically what you do here is just evaluate the radiological source term in the reactor coolant for the EPI conditions, the power uprate. And the evaluations performed show that the source term continues to meet the requirements of 10 CFR Parts 1, 10 CFR Part 50, Appendix I and General Design Criteria-60.

The next portion of the discussion involves the design bases accident radiological consequences analyses. Again, this is covered in section 2.9.2 of the SE. And the licensee has implemented the alternative source term in all of the radiological analyses performed. For the actual EPU submittal, the analyses that needed to be looked at were the fuel handing accident because of an increase in fuel inventory and the main steamline break and the steam generator tube rupture for Unit 2 only due to change in mass release. All the other design bases accidents have been previously approved, and I'll go through that a little bit later.

For the radiological consequence analyses, the EPU power -- the power level evaluated was 2,918 megewatt thermal. And this represents a 100.6 percent of the rated power of 2,900. And this is based on the approval of a 1.4 percent measurement uncertainty recapture uprate.

And we also wanted to mention the NRC Staff performed an onsite audit of the radiological analyses supporting both the steam generator replacement license amendment request as well as the EPU.

Other DBAs have been evaluated as part of a selective implementations under 10 CFR 50.67. The loss of coolant accident and the control rod ejection accident were evaluated, Amendments 256 and 139 which were issued September 10, 2003.

The locked rotor accident and the loss of AC power and the small line break outside of containment for both units. And the main steamline break and the steam generator tube rupture accident for Unit 1 only. All those accidents were evaluated in Amendment 273 for the steam generator replacement issued February 8, 2006.

Put up a slide that concerned the control room. The evaluations for Beaver Valley and for those accidents in the EPU, the control room emergency ventilation system is credited for the main steamline break. They credit a pressurization mode, as it says, 500 cfm filtered intake. And during that period the license is assuming 30 cfm of unfiltered inleakage. And the licensee performed tracer gas testing which support the unfiltered inleakage assumptions.

For the accidents discussed here, the licensee credits a control room purge, a post-release control room purge. And in order to do that they credit the control room emergency air cooling system. And this system is credit for post-release purging for the steamline break, the steam generator tube rupture and for the Unit 1 fuel handling accident. Again, at the times when those releases are assumed to have ended.

The purge credit was not needed for the Unit 2 field handling accident because of more favorable meteorology for that particular half.

And basically the design bases accident rate radiological consequences, the licensee has adequately accounted for the effects of the proposed EPU and all the design bases accidents meet the 10 CFR 50.67 and Standard Review Plan 15.0.1 dose acceptance criteria for both offsite and the control room. And the Staff finds the proposed EPU acceptable with respect to the radiological consequences of design bases accident.

CHAIRMAN DENNING: Well, thank you very much for a focused presentation.

Do you have a question.

MEMBER KRESS: Yes. Here the source term you're talking about, the AST, the source term into containment, did they then use the MAAP code to subsequently get the release to the environment and the transport to the control room?

MR. PARILLO: No. The guidance in the Standard Review Plan pretty much is a cookbook. It dictates the percentage of the radionuclides that are released to containment. And the codes that are used for radiological analyses are not quite as sophisticated. They don't need to be. They're just volumes. So you start with so much activity in this volume and it leaks into another volume and eventually to the environment, and then leaks back into the control room. So we don't use the MAAP code.

The licensee, their calculations were done with Stone & Webster proprietary code, but we did confirmatory analyses with the RadTRAC code, which is the code we use at the NRC for these types of analyses.

CHAIRMAN DENNING: Okay, Tom. You happy?

MEMBER KRESS: No, but that's all right.

CHAIRMAN DENNING: Are you done?

MEMBER KRESS: Yes, I'm done.

CHAIRMAN DENNING: Okay. Thank you very much.

MR. PARILLO: Okay.

CHAIRMAN DENNING: Okay. And now we're going to hear about materials and reactor vessel integrity from FENOC.

MEMBER WALLIS: Just please start when you're ready.

MR. WEAKLAND: All right. My name is Dennis Weakland. I'm been with Corporate Materials for 3 or 4 years. Prior to that I've had 24 years experience with Beaver Valley primarily in the areas of materials inspections, analyses and the like at Beaver.

I've also been very active in the industry initiatives in materials -- owners group.

What I'd like to talk about a little bit on the materials construction, the integrity programs that we have, the Alloy 600 management and the vessel integrity.

The reason I emphasize the Alloy 600 and vessel integrity is I think these are the areas that are most important with the EPU uprate. And we'll discuss those in a little greater detail.

Our basic materials construction our reactor vessel, our steam generator and pressurizer are carbon steel vessels clad with stainless steel. Penetrations in these areas are stainless steel with a few Alloy 600 penetrations primarily at Unit 2.

RCS loop piping is Cast SS material. This is a really robust material in the RCS areas dealing with things like boric acid are not an issue. There is some concerns in license renewal license extension space as far as thermal embrittlement. Areas of that are not within the current license life.

And the balance of the RCS piping in both units is stainless steel, again robust material, high fracture toughness and not subject to boric acid corrosion.

The vessel components and welds are primarily stainless steel. A few at Unit 2 for Alloy 600, and I'll touch on those a little bit later.

So in general the Westinghouse design with a combination of the Cast SS, the stainless steel really provides a pretty robust RCS system to minimize the number of vessel and component welds.

The investment integrity programs we have, the steam generator integrity program complies with the 97.06. We've adopted it at Beaver Valley. It performs operational assessment at every outage. So the effects of the EPU, and since there's virtually no change in the hot leg anyhow from 609 to 609.5, we expect a little change. But we did do an operational assessment coming out so we know the status of everything coming out of every outage.

The Alloy 600 program we complied with the industry standards, primarily MRP 126 and 139.

The boric acid program is run under the WCAP which is the industry program 15.988. And we're adopting the material degradation program under NEI or 308 initiative to have an integrated materials program on our site, and those will be effective come June 1st this year in accordance with our 308 and the NEI initiative.

Together with the other operational programs we have and systems programs and things like system engineering routinely test our systems, our maintenance rule operational tools, BVTs that we run, we have a very good handle on the integrity of our systems and minimize the amount of damage. We see anything occurring, it's back into the system, repairs do occur and we address the issues while they're small.

So, as you see, we take these programs as a whole. We ensure the system integrity is maintained and degradation issues are identified at our earliest possible times and take appropriate mitigative actions.

This carton I thought was appropriate because it kind of covers both units. The basic RCS is the same. And right here these surge nozzles are only in a tube that are Alloy 600. Unit 2 has the vessel piping along with an Alloy 600 weld that we'll have to address. And the balance of this is all 315, 309 type material. So we have very, very limited amounts of Alloy 600 material.

The recent outage we've replaced all the Alloy 600 material at Unit 1 in the top of our head, taken it out of the picture, mitigated it and gone to 690.

At Unit 1 all the Alloy 600 materials in the steam generator at Unit 1 have been removed and are now 690. And at Unit 2 that will be managed under the existing program.

MEMBER WALLIS: 690 is a pretty new

material, isn't it? We don't really know what the problems are with it yet?

MR. WEAKLAND: No. The information that we have from the industry looking at the Naval reactor information and overseas information on 690 appears to be extremely robust. We can't put on a number on what it is. So as a result, the testing protocols that are done by the industry in 03.009 will continue the timing models and the Uranus equations that are used for Alloy 600 as a very conservative measure. As more is learned, those may be relaxed. But currently we would follow the same protocols.

DR. BANERJEE: So there is information on exposure to boric acid and everything for 690?

MR. WEAKLAND: 690 is used widely within the nuclear Navy in the borated systems.

DR. BANERJEE: And no problems?

MR. WEAKLAND: And they're robust. And 600 to the best of our knowledge.

MEMBER SIEBER: Navy plants are correlated, are they?

MR. WEAKLAND: Not the Navy, but the Alloy 600 testing, there's Alloy 600 testing to 690 that's been done at Westinghouse Labs and whatnot has shown no issues with the nickel based alloys as referred to

Alloy 600 and boric acid.

The austenitic materials 316, 309 when it comes to Alloy 600, you have very little problems.

DR. BANERJEE: So 690 is used in the Navy but the Navy uses borated systems or not?

MR. WEAKLAND: No, no.

MR. KAMMERDINER: This is Greg Kammerdiner from FirstEnergy.

As far as industry experience with 690, at least in steam generators, Indian Point 3 was the first one to switch to 690 in 1989. So we have quite a bit of experience from that date forward with 690 both domestically and internationally prior to 1989. I think Ringhalls was the first one to replace a steam generator with 690. And those steam generators have basically performed degradation free since the late '80s with 690.

MR. WEAKLAND: The next slide we cover the head inspections that we're doing at Beaver Valley Unit 2, which is mainly 600 material and these are the two heads at the two units. And this coming fall we'll doing -- well, the past fall, the fall of '03 we did bare metal visuals, found no degradation and volumetric of CDRM and J-welds, did an Eddy current examinations of the outside and no degradation.

In the spring of '05 we repeats in accordance with your order the bare metal visuals and we have volumetrics coming up this fall at the same unit for ongoing evaluations of the head inspections.

At Beaver Valley Unit 1 we've taken a very active approach on the mitigation of the Alloy 600. As I noted, we replaced the head, the steam generators and I just completed 1R17 outage this spring. This next fall we're planning on doing a weld overlay on the pressurized nozzles, which are the 600 dissimilar metal welds that we have to top the pressurizer. So we'll mitigate those, put them in a compressive state and we will continue to monitor them in accordance with the industry guidance.

MEMBER SIEBER: Do you have any indications on the places where you're going to do the weld overlays right now?

MR. WEAKLAND: No.

MEMBER SIEBER: So this is a preventive --

MR. WEAKLAND: Preventive overlay, yes.

MEMBER SIEBER: Okay.

MR. WEAKLAND: We're planning the same kind of preventive overlay in Unit 2.

MEMBER SIEBER: You're going to compress the fitting?

MR. WEAKLAND: Correct.

MEMBER SIEBER: Okay.

MR. KAMMERDINER: Again, this is Greg Kammerdiner again.

Besides inducing a compressive stresses, will be full structural overlays also. So it's a double measure here. Inducing the compressive stress on the existing 82/182 weld material plus full structural overlay of 690 on top of that.

MEMBER SIEBER: Well, if you're going to have problems, that's a good place for you to have them.

MR. WEAKLAND: They would be the likely suspects?

MEMBER SIEBER: Yes.

MR. WEAKLAND: Right.

The remaining Alloy 600 therefore at Unit 2 would be limited to the BMNs, the bottom mounted instrumentation. We'll continue to inspect those in accordance with the industry guidance. And then the reactor vessel internals, there's some Alloy 600 in there that we'll be addressing.

CHAIRMAN DENNING: Now to a large extent what you're talking about is not necessarily related to power uprates.

MR. WEAKLAND: No.

CHAIRMAN DENNING: As far as power uprates are concerned though there is some temperature increases--

MR. WEAKLAND: Slight temperature increases. Unit 2, that half of degree is virtually nonexistent in the space.

CHAIRMAN DENNING: Yes.

MR. WEAKLAND: Unit 1 it's approximately a 4 degree increase and there's very limited material that would be effected here. So from a power uprate perspective the materials construction really don't see much different.

CHAIRMAN DENNING: Well, we're certainly interested in this.

MR. WEAKLAND: Okay.

CHAIRMAN DENNING: But it does seem that a lot of it, except within the context of some temperature increase is why would have some additional concern about it.

MEMBER SIEBER: Well, I think just to amplify that a little bit, some folks suspect that there's sort of a need in the curve, right around 610. When you go beyond that the rate of degradation in some folks speculation may increase. And so you're right at that point. But I agree, the temperature increase is very small.

DR. BANERJEE: But isn't it very sensitive to temperature in this range, the susceptibility?

MR. KAMMERDINER: This is Greg Kammerdiner again.

I think the emphasis though is our degradation throughout the industry has primarily been at Ally 600 locations.

DR. BANERJEE: Right.

MR. KAMMERDINER: And what Denny's trying to point out here at Unit 1 we've eliminated that, for the most part, from the equation by replacing the generators with 690, by replacing the head penetrations with 690, we're planning to overlay the pressurizer nozzles, which are essentially Alloy 600 welds. There will be minimal amount of Alloy 600 left at Unit 1 and the bottom nozzles operate at cold leg temperature, so they should be on the lower susceptibility ranking of locations.

So as far as Unit 1 the 4 degree increase in temperature is somewhat mute at this point because we've basically taken the Alloy 600 out of the equation.

MEMBER MAYNARD: I believe it is sensitive in this range, but I think that for the temperatures you're going to they're still within what there's good history out there within industry. They're not becoming an outlier from breaking the ground.

DR. BANERJEE: Right. And Alloy 600 is out, this unit with the 4 degree rise. The other unit only has half a degree, right?

MR. WEAKLAND: Yes, sir.

MR. KAMMERDINER: Correct. Right.

MEMBER SIEBER: I think the interesting thing that sort of gives you some confidence is that one of the suspect heats was used in the Beaver Valley 1 reactor vessel head nozzles, the same one that didn't do well at Davis-Besse.

MR. WEAKLAND: Right.

MEMBER SIEBER: And they have seen a leakage or other problems there. But they have still replaced the head.

MR. WEAKLAND: Yes, that's correct.

MR. PATNAIK: I'm Pat Patnaik from DCI, Dividend of Component Integrity.

I want to add one more thing here. That the cold leg temperatures go down actually by a couple of degrees. As a result I don't see any problems with the bottom mounted nozzles.

MEMBER SIEBER: Right.

MR. WEAKLAND: Right. Thank you.

I will then just brush over what's at Unit 2 just to give you an idea of what plans are on Alloy 600.

We are planning mitigation in the areas for pressurizer nozzles for weld overlay. Management's currently looking at multiple approaches to address the cold leg loops, as we have Alloy 600 there. I think which will leave us with the BMNs, the internals, the generator tubing and the CRDM nozzles. And since the amount of temperature movement is very, very slight, we would expect no change from our current history, and we'll continue our inspections.

The other thing I want to touch on where the power uprate does have some effect because of the increase of fluence and the fluence impact is the area of materials for the two units. I'm going to talk a little bit more about the fluence, the uprate, the increases in improved capacity factor and what it has done with our projected EFP wise and end of expected life.

When we looked at the surveillance schedule, there will be no change in our schedule. We'll still pull five capsules for Unit 1, four for

Unit 2 in accordance with Appendix H. No changes there.

The upper shelf energy, both units at the end of -- actually at the end of extended life because I've done some of that with our projections there, are still good for upper shelf. So really the impact for the power uprate has been minimal for upper shelf.

Our PTS screening criteria for Beaver Valley Unit 1 and Unit 2, both our units are a little unusual in the industry in that they're both plate limited. Many vessels or most vessels are actually weld limited. Ours are plate. And I'll touch on the numbers we have those in the next slides.

We've looked at the applicability for the heat up and cool down curves. In the application what we did is we artificially took our existing heat up/cool curves for Unit 1, conservatively rolled back the effective dates so that until the LAR gets into position, that the effected curves have just been moved from 20.80 EFPY to 27.44 so that we know we don't exceed those limits. Base the fluence for heat up and cool down. As we do more testing and analysis then we'll adjust those in accordance with our PTLR and move forward.

Okay.

In the area of fluence in relationship to the uprate, we used a basis for WCAP Capsule & material at 3.54 E19 fluence. And our RTpts based on that fluence is 259. Capsule Y meant it was a major change in our fluence projections. We gained almost 12 degrees, which is very good. And that assumed a 1.4 uprate, but did not address the 8 percent uprate at the time that capsule was pulled. So when we made the uprate LAR and backed the effected EFPYs down, assuming that a power uprate would have done in June of '03 and holding the fluence constant at 3.54.

At Beaver Valley Unit 2 we used a Capsule Y data of 32 EFPY, fluence of 3.8 and RTpts of 149.

And incidentally, the RTpts screening number is 270 for plate for both units. It had included the 1.4 percent uprated and the 8 percent uprate. So the Unit 2 numbers were reflective of a June '03 power uprate, so they are conservative.

MEMBER SIEBER: Have you made any projections for renewed license end of life?

MR. WEAKLAND: Well, that's going to lead to the next slide, Jack. Thank you.

MEMBER SIEBER: Yes.

MR. WEAKLAND: As a result of looking at a potential extended license and the excellent operation of the past three cycles at Beaver Valley operating capacity factor in the high 90, 97, 98 percent; projecting those kind of capacity factors into the future and the 8 percent power uprate based on June of '06 what we're seeing now is an expected end of life EFPY of about 30.5 at the same fluence.

MEMBER WALLIS: Doesn't the fluence change with the uprate?

MR. WEAKLAND: Well, the fluence in this particular case didn't happen to change from the projection because the projection was made assuming that the uprate would have occurred in June of '03. And since the fluence is really controlled by core and when the uprate occurred, the 3 years delay provided me that cushion. And the core design being maintained at L4P has maintained the fluence at 30.5, virtually 3.54. The numbers like -- it's like 3.51 or 3.52 is very, very close to 3.54. At 30.5 at the end of our existing license life. That's reflective of the capacity factor and then this uprate in June this year.

At Unit 2, it's just coincidental I had a capsule due. It came to the NRC last week, so it's very new information to them, the submittal. And I did the projection of 36 EFPY for EOL. The reason I did that is when I did the projections looking into the future based on the higher capacity factors, it looks like we'll be at the end of our 40 years license somewhere around 35.1 to 35.2 actual EFPY. So 36 pounds allows me to be conservative.

As you can see, both of them give me RTpts that are still well below the screening criteria.

MEMBER WALLIS: Well RTpts doesn't seem to change at all as you do all this --

MR. WEAKLAND: No. It's based on fluence, that's why.

MEMBER WALLIS: But your fluence has changed for BV2.

MR. WEAKLAND: BV2 the fluence -- the difference between the two numbers, too, it comes into rounding of RTpts. At the earlier fluence of 32 FPY I think it was 3.86. The actual number when you run it and if you run out a decimal point or two, it's like 148.7.

MEMBER WALLIS: Well, it's so low it doesn't--

MR. WEAKLAND: It just doesn't matter. Right. And that's the reason for those activities.

MEMBER SIEBER: Well, what will it be after 60 years of licensed operation? Do you know that?

MR. WEAKLAND: On Beaver Valley Unit 1 we could reach 60 years of power operations and still be below the 270 criteria right now.

MEMBER SIEBER: You will?

MR. WEAKLAND: It's going to require some fuel management, some continued fuel management. We stay at L4P, we get within 2 years of extended license operation doing absolutely nothing different than we're doing today.

MEMBER SIEBER: I think you don't make it.

MR. WEAKLAND: We can make it.

MEMBER SIEBER: Oh, you can, okay.

MEMBER WALLIS: By then the PTS rule may have changed.

MR. WEAKLAND: Yes. Well, we believe it will be changed. Beaver Valley was the model plant for the NUREG and it's been very well studied by Oak Ridge. And if I look at their numbers, I'm probably good for a 100 EFPY, and I like their numbers.

MEMBER SIEBER: Too bad it's not regulation.

MR. WEAKLAND: Oh, yes. We're working on it.

In summary, the temperature assessment for the two units show really no programmatic impact on either the Alloy 600 or the steam generator program.

Fluence assessments, no significant impact on either the vessel integrity, upper shelf.

Maintaining our core, I don't see any problem. There's some small changes in response to materials. It will be managed under the rest of our programs. That primarily deals with internals activities, BMNs and the rest. And we have programs in place to monitor and maintain those through the rest of plant life.

MEMBER SIEBER: How many tubes are plugged percentage wise in Unit 2, steam generator 2?

MR. WEAKLAND: Unit 2? Greg?

MR. KAMMERDINER: This is Greg Kammerdiner.

Approximately 4½ percent.

MEMBER SIEBER: Pretty much even across the--

MR. KAMMERDINER: Pretty much. Yes, it's not like Unit 1 where we're skewed the one generator there. They're pretty evening distributed.

MEMBER SIEBER: What's the main reason?

MR. KAMMERDINER: Primarily sludge pile ODSCC.

MEMBER SIEBER: Thanks.

MR. WEAKLAND: Okay. That's all I have.

CHAIRMAN DENNING: Thank you very much.

MR. WEAKLAND: Any other questions?

CHAIRMAN DENNING: Hearing none, we will move on.

MR. WEAKLAND: Very good. Thank you.

CHAIRMAN DENNING: However, this is our final presentation of the day.

MR. MEDOFf: Good afternoon. My name is Jim Medoff. I'm a materials engineer for the --

DR. BANERJEE: Where are the slides for this?

MR. MEDOFf: They're in this package.

MEMBER WALLIS: Yes, the pages keep starting all over again.

MEMBER SIEBER: And you thought you were going to talk about materials.

DR. BANERJEE: Yes. It's after the control room thing.

MR. MEDOFf: Right.

MEMBER KRESS: Let me ask you a question, what did you do about the containment?

MEMBER WALLIS: What don't you start with page 7?

MEMBER SIEBER: Pretty good condition.

MEMBER WALLIS: A good slide to start with.

MR. MEDOFf: Good afternoon. I'm Jim Medoff. A materials engineer currently with the Flaw Evaluation and Welding Branch. My current supervisor is Dr. Kimberly Gruss. I just recently transferred over from the Reactor Vessels Internals Integrity Branch, which is currently being supervised by Mr. Matt Mitchell.

At the time of the EPU I was in the Reactor Vessels Internals Integrity program.

I'm here today to talk about our evaluation of the licensee's application with respect to the structural integrity of the reactor vessel and the reactor vessel internals components, and as well as the licensee's evaluations of its reactor coolant pressure boundary materials. And with respect to that, we're going to focus on the Alloy 600 and what they did to address it.

Next slide, please.

For the EPU we assessed the Staff's evaluation of how the EPU impacted the structural integrity of the Alloy 600 components, in particular whether it would change the crack growth rates if you postulated a crack occurring in the Alloy 600 components. And these included Alloy 600 base metal components as well as Alloy 682 or 182 filler metal materials.

For the most part, the piping at Beaver Valley Unit 1 doesn't include Alloy 600 materials, so we don't see a big impact on that. And Mr. Weakland provided a good summary for where the few components are located and addressed how they addressed structural integrity there.

For the Alloy 600 and the Alloy 82/182 welds in the Beaver Valley Unit 1 reactor vessel closure head, we determined that the licensee did replace the head in the last outage and we feel that the monitoring program that they're going to do this under the schedule for replacement head should address this. It includes not only Alloy 600 and 82/182 materials, but the ordered that we issued to the industry on Inconel materials also covers Alloy 52, 152 and Alloy 690 materials. So just the fact that they replaced the new materials doesn't change the requirements in the order and they're still required to follow that.

Next slide, please.

For Unit 2 the Alloy 600 and Alloy 82/182 materials in the Unit 2 reactor coolant pressure boundary are managed by the licensee's Alloy 600 management program. And what this program does is it does a susceptibility ranking of the components based on -- the susceptibility program is basically Uranus program that is a function of the temperature of the components.

DR. BANERJEE: There's no effect of stress on the -- I thought there was, as well -- I mean temperature is one effect, but stress must be another.

MR. MEDOFf: Stress probably comes in it, but I think the big factor in the Uranus program is the temperatures.

MR. PATNAIK: This is Pat Patnaik from Dividend Component Integrity.

The analysis has been done at 617 degrees which bounds the temperatures for power uprate.

DR. BANERJEE: Right. But --

MR. PATNAIK: That was done, has been done at a bounding temperature of 617 degrees. And with power uprate your hot leg temperature is not going over 611.3 degrees.

DR. BANERJEE: I'm just saying about the susceptibility ranking.

MR. PATNAIK: Susceptibility ranking?

DR. BANERJEE: Yes.

MR. PATNAIK: Well, the components that are Alloy 600 and welded with 82/182 filler metal have been ranked based on stresses and also the time and temperature.

DR. BANERJEE: Right.

MR. PATNAIK: Yes, that ranking has been done. And their volumetric inspections will be performed according to the susceptibility ranking--

DR. BANERJEE: Which take both factors into account.

MR. PATNAIK: Oh, yes.

DR. BANERJEE: Yes.

MR. PATNAIK: Of course.

DR. BANERJEE: All right. I'm happy with that.

MR. PATNAIK: Go ahead.

MR. MEDOFf: Okay. and in accordance with this program what they're going to do is they select the susceptible components for augmented inspection and they put the inspection in accordance with the program. So they do monitor for their Alloy 600 and Alloy 82/182 materials in Beaver Valley Unit 2 plant.

With respect to the Alloy 600 nozzles and Alloy 81/182 partial penetration welds in the Unit 2 head, they are categorized as highly susceptible heads to primary water stress corrosion cracking and FirstEnergy does perform augmented inspections of these things in accordance with the criterion in the first order for high susceptible reactor vessel closure heads. And this complies with the rule and should address structural integrity for those components.

Next slide, please.

From my review I reviewed the impact of the EPU on the reactor vessel and the reactor vessel internals, the internals components.

With respect to the reactor vessel, we really focused on how the EPU would impact the fracture toughness assessments that we require for the ferritic

materials in the reactor vessel. This includes the RTpts calculations to ensure integrity against the events of a pressurized thermal shock event. The RTpts calculations that go into the pressure temperature limit calculations, the upper shelf energy calculations for demonstrating margins against -- tearing of the reactor vessels materials and each of those assessments requires that they account for the effects of irradiation and they monitor for that through their reactor vessel surveillance program. So we assess the impact of EPO on the withdraw schedule for that program.

We also looked at the impact on the structural integrity of the RV components. And I'll address that later on in the presentation.

Next slide, please.

With the impact on the RV surveillance capsule program, the program's required by 10 CFR Part 50 Appendix H. And basically the rule requires them to withdraw surveillance capsules in accordance with ASTM Stand EI185-82. In accordance with that standard the licensee is required to pull 5 capsules from Beaver Valley Unit 1 and 4 capsules from Beaver Valley Unit 2. And it's really dependent on what the limiting shift in the reference temperature will be for that vessel at the end of life.

We found out that there were a few minor adjustments to the withdrawal schedules for the remaining capsules because each one has one remaining capsule to get pulled. And I'm not sure whether that report that Mr. Weakland referred to in his presentation was actually one of those capsules. But from the data I had, they were still required to pull two capsules for the plants.

Basically, we find that the changes that they propose to the schedules were still in accordance with the ASTM standard and so we found that the EPU didn't impact the overall schedules for the units. We found them to be acceptable.

Next slide, please.

For the PTS assessment, the calculation of RTpts values is required by 10 CFR 50.61. As Mr. Weakland said, the rule establishes screening criteria of 270 degrees for reactor vessel base metals and axial weld materials. And a screening criteria of 300 degree for reactor vessel circumferential weld materials. And these are upper limits on the adjusted reference temperature for RTpts value.

The licensee gave you his values. We did independent calculations of the RTpts values using our reactor vessel integrity which mods the methodology in the rule for doing these calculations. And we came up with an RTpts value 259.5 based on the fluence provided by the licensee for Unit 1. And RTpts value of 148.6 degrees F for Unit 2 based on their end of life fluences. And therefore, we didn't see any impact of the appeal in compliance with 10 CFR 50.61.

Next slide.

Basically we looked at the impact on the pressure temperature limits, but to make it sweet and short, Generic Letter 9603 allows them remove their pressure temperature when it's from the limiting conditions of operations in the technical specifications if they put them into a owner controlled documents called the Pressure Temperature Limits Reports. And they calculate them within an NRC approved methodology, any changes to those technical specifications PTLR figures are done through an administrative tech spec.

We granted license amendments for them to do this in 2002 and 2003. And although there may be changes in the RTndt calculations that goes into these PT limit calculations, they'll be done through the PTLR process, and that's acceptable to us.

Next slide, please.

Like the RTpts calculations, we looked at the impact on the effort of shelf energy assessment for the plant. Basically we used this parameter as a measure of looking at the remaining ability to withstand ductile taring in the reactor vessel materials. It's governed by 10 CFR Part 50, Appendix G.

The rule establishes that the upper shelf energy values must be greater than 75 foot pounds in the unirradiated condition and greater than 50 foot pounds through the licensed life of the plant including all of accounting for the effects of irradiation.

We did our independent calculations of the upper shelf energy values for limiting materials and we agree that the limiting materials for Beaver Valley are all plant limited, both for RTpts and for upper shelf energy. We calculated for Unit 1 an upper shelf energy value at end of life under EPU conditions of 53.8 foot pounds and for Unit 2 a 59.4 foot pounds. Both of these comply with the acceptance criteria 50 foot pounds at end of life. So we didn't see an impact on the ability to comply with 10 CFR Part 50 Appendix G.

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The last thing we assessed is the impact on the structural integrity for the reactor vessel internals. All of our assessments were done in accordance Matrix-1 of Review Standard RS-001. And with respect to this we really look at whether the fluence for these materials above a certain level, a certain threshold because above that threshold there is a concern that the materials, the components maybe susceptible to irradiation assisted stress corrosion cracking. And what the matrix specifies you should do if you're above the fluence is either provide a commitment and provide an augmented inspection program for these components or commit to participation in industry initiatives that are being performed on age related degradation of these components. And we sent out an RAI informing the licensee of this document, and they did provide the proper commitment to the NRP initiatives. And this satisfied the matrix. And so we concluded they were sufficient for the RV internals.

So basically we assessed six things: The Alloy 600 materials, the structural integrity of the RV internals, the PTS assessment and the upper shelf energy assessment and the RV surveillance program. And we concluded that an impact to safety margins or that they were providing commitments to provide augment inspection programs.

CHAIRMAN DENNING: Questions?

MEMBER WALLIS: Thank you.

MR. MEDOFf: Thank you.

CHAIRMAN DENNING: According to the agenda, it is now 5:00 p.m., so we will recess.

(Whereupon, at 6:09 p.m. the hearing was adjourned until 8:33 tomorrow morning.)