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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

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WEDNESDAY,

MARCH 15, 2006

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The meeting was convened in Cabinet/Judiciary Suite of the Hyatt Regency Hotel, Bethesda, Maryland, at 8:30 a.m., Dr. Richard Denning, Subcommittee Chairman, presiding.

MEMBERS PRESENT:

RICHARD S. DENNING, Chairman

JOHN SIEBER

GRAHAM B. WALLIS

OTTO L. MAYNARD

ACRS STAFF PRESENT:

RALPH CARUSO

SAM MIRANDA

NRC STAFF PRESENT:

PATRICK MILANO

JOHN NAKOSKI

KENT WOOD

BRIAN LEE

CHRIS McHUGH

NEIL RAY

JOHN WU

RAUL HERNANDEZ

ALSO PRESENT:

MARK FLAHERTY	Constellation Power
MARK FINLEY	Constellation Power
JIM DUNNE	Constellation Power
ROY GILLOW	Constellation Power
DAVE WILSON	Constellation Power
GORDON VERDIN	Constellation Power
JEFF KOBELAK	Constellation Power
JOE PACHER	Constellation Power
GEORGE WROBEL	Constellation Power

A-G-E-N-D-A

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

8:30 a.m.

CHAIRMAN DENNING: The meeting will co me to order. This is the Advisory Committee on Reactor Safeguards Subcommittee ion Power Rates. I am Rich Denning, Chairman of the Subcommittee.

The Subcommittee members in attendance are Otta Maynard, Jack Sieber and Graham Wallis.

The purpose of this meeting is to discuss the extended power uprate application for the Ginna Nuclear Power Plant. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC Staff and the Ginna licensee Constellation Energy 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 designate federal official for this meeting.

The rules for participation in today's meeting have been announced as part of a notice of this meeting previously published in the *Federal Register* on March 3, 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 that they can be readily heard. We have a very limited number of microphones in the room here, so that's going to be a little painful. But please make sure you go to a microphone when you make a statement.

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

Review of an application for a power uprate is one of the most challenging activities that the NRC undertakes. Based on source term alone we know that the risk will increase by at least 17 percent due to this application. But the subtle change in risk is associated with decreased in safety margins. We have to look carefully at those margins, the uncertainties and determine whether the increment to safety limits are still adequate.

Let me first say what we don't want to hear today. We don't want to hear a checklist of areas of reviews where the change in plants conditions is negligible and the safety of the plant is unaffected.

If you have any viewgraphs of that type, tell us why you're going to jump over them and move on.

What we do want to hear about today are the results of quantitative analyses. We want to see changes in margins, the effect of uncertainties. If you present sensitivity studies, we want to know what the basis was for the range selected for those sensitivity studies. We want to hear about processes that would be affected by changes in conditions such as vibrations in equipment, flow accelerated corrosion. And we also want to hear about the programs that will identify approached on safe conditions.

Now, as I've looked at the agenda I think that it is appropriate and that we will focus on the important things that we do want to review.

We will now proceed with the meeting and I call up Mr. Milani of the NRC Staff to begin.

MR. MILANO: Good morning. All right.

Again, my name is Pat Milano. I'm the Senior Project Manager in NRR for the Ginna and Calvert Cliff Stations.

Before I get started here, I'd like to give a little bit of background for the application. The application came in on July the 7th of 2005 and subsequent there have been a series of supplement to that ranging from last August through now.

The application itself was provided to us in two specific parts; basically the overview with the technical specifications that are going to be changed and then the licensee's analysis presented in terms of what we call a licensing report.

The presentations today are going to be focused on several topics. One is the fuel and core design, which will be presented by the licensee, followed by safety analysis focusing both on the reactor systems areas an dose consequence. And then a presentation on risk.

You'll notice here there's a slight change to the agenda. We're going to talk about electrical impacts, predominately grid and power delivery. The licensee's member has a conflict tomorrow, so we had to move this one up earlier.

And then as you see here the remainder of the afternoon will be mechanical matters, reactor vessels, the various degradation mechanisms and then we'll talk about some of the mechanical systems, predominately in the balance of plant.

Tomorrow will be limited. We'll be talking about operations and testing, human factors issues.

MEMBER WALLIS: Can I ask that when we get these presentations we hear where we are today and what the effect of the uprate will be. The safety evaluation report simply seemed to say they meet all the requirements. But I like to know the value of some parameter is something today, this uprate will change it by this much and here's the limit. And I did not see that. And maybe this is all going to happen, but that's what I'd like to see. I'd like to know what the change is and how close we are to limits in every one of these categories that's important.

MR. MILANO: The application, the July 7th application came in after several preapplication submittals. There were three amendments that came in in late April. One for relaxed axial offset control, one for main feedwater isolation valves and one for revised LOCA analyses methodologies. Of these three, three constrain the approval or the Staff's approval of the power uprate. The power uprate itself assumes that these three amendments have been previously approved. And just for a quick status, the axial offset control was approved on February 14th. Main feedwater isolation valves has the Staff review and along with the OGC review had been completed and it's in the final stages of administrative processing with the expectation of issuance by the end of the week. The revised LOCA analysis continuing to be reviewed by the Staff.

The Staff's schedule basically centers on the licensee's need date for implementation. The licensee plans to implement the power uprate --

MEMBER WALLIS: Excuse me. Revised LOCA analysis; is that because it's now being done a different way?

MR. MILANO: Yes.

MEMBER WALLIS: Is there going to be a comparison with the old way or are we just going to see the new way?

MR. MILANO: No. There will be no comparison with the old way.

MEMBER WALLIS: Presumably they're choosing the new way because it's favorable to do it that way?

MR. MILANO: Yes.

MEMBER WALLIS: So it might be interesting to see what would have happened if they did it the old way? But we won't see that?

MR. MILANO: No, you will not.

MEMBER WALLIS: Okay.

MR. MILANO: Okay. As I indicated, the schedule is constrained by the licensee's requested implementation during the fall 2006 refueling outage. Right now the Staff's schedule -- excuse me. The draft safety evaluation has been issued with the exception of the open item, although in the LOCA analysis area the Staff has completed its review of the large break and the non-LOCA transients. However, the Staff continues to review a combination of issues centered around small break LOCAs, long term cooling and boron precipitation. The expectation is for the Staff to complete its review of those areas on or before April 4th. That portion of the safety evaluation will be provided to the ACRS in order to meet the next Subcommittee meeting late in April wherein those issues itself will be talked about after the Beaver Valley Subcommittee meeting. And then followed on with the May 4th full Committee meeting.

Based on that, the Staff's goal is to issue the safety evaluation in the July or early August time frame.

With that, that concluded my presentation with regard to the introduction. Baring any questions, I'm going to turn it over to the licensee for their introduction.

MR. FLAHERTY: My name is Mark Flaherty. I'm the Acting Vice President of Nuclear Technical Services with Constellation Generation. I'm out of the corporate offices in Annapolis, Maryland.

Previous to that I was at Ginna Station for approximately 15 years where I received my SRO cert and was an STA for approximately one year and held management positions in engineering, licensing and PRA.

So we're glad to be here to have this opportunity to talk to ACRS about the proposed uprate. I'll start off with a high level overview introduction. And I'll be followed by Mark Finely, who will discuss the plant changes. Mark was the project manager for this with Constellation. He'll be followed by Dave Wilson who will go over the process focusing on the licensing issues. And then followed by Gordon Verdin who will discuss the fuel and core. And then also Mark Finley will come back and discuss safety analysis. Rob Cavedo will discuss risk evaluation. Jim Dunne will discuss mechanical impacts. Joe Pacher will discuss electrical impacts. Roy Gillow will discuss operations and testing. And then I'll conclude tomorrow morning.

With respect to the introduction, I'm

going to discuss a little bit about the design and operating history for Ginna, some initial preparations that were done for the uprate prior to initiation of this project. And also some of the executive oversight that was done both from the site perspective and from Constellation Corp's perspective.

With respect to the history of Ginna, Ginna is a Westinghouse two loop 1520 megawatt thermal intercourse design. Went commercial operation in 1970. And the original license power level was for 1300 megawatts thermal. In 1972 it was uprated to 1520 megawatts thermal consistent with its sister plants Kewaunee, Point Beach and Prairie Island.

The uprate that we're proposing and discussing today brings us up to 1775 megawatts thermal, which is very consistent with the current operating level of Kewaunee, one of the Ginna sister plants.

MEMBER WALLIS: Are you going to tell us why it's 1775 and not 1800 or some bigger number? Is there some limiting phenomenon which determines that it should be 1775?

MR. FLAHERTY: Yes. Mark Finely will address that in the next --

MEMBER WALLIS: So there is one particular phenomenon that limits? What is it? Or is it a whole bunch of phenomenon?

MR. FINLEY: Well, we'll get to that.

MEMBER WALLIS: You will explain that?

MR. FLAHERTY: Yes.

MR. FINLEY: In the safety analysis section.

MEMBER WALLIS: Because it wasn't clear to me where you were limited. And you're going to tell us that clearly?

MR. FINLEY: Yes.

MEMBER WALLIS: Okay. Thank you.

MR. FLAHERTY: Prior to pursuing the uprate project for Ginna Station, some activities occurred at Ginna that did set the stage for allowing us to go for uprate. This included in 1996 we did replace the steam generators at Ginna. And the replacement steam generators were sized sufficiently to provide the opportunity to pursue uprate when the company desired to pursue that.

Also in 2003 we did replace the reactor vessel head for Ginna Station.

With respect to the team itself, we elected to pursue a very experienced project team that included Westinghouse, Stone & Webster and Siemens.

And many of those individuals are here in this room also.

We also provided a lot of executive oversight. This is both from a standpoint from a corporate perspective and also from a vendor perspective and industry experts with the intention being that we wanted to use as much operating experience as was available out there for people that had pursued uprates and to bring that to the team to make sure that those were addressed up front and throughout the project.

As far as the executive oversight, Constellation senior management was closely involved. This includes both site management, the site Vice President and plant General Manager and those individuals, and also from a corporate perspective from within Annapolis.

We formed an Executive Oversight Committee, and that has met eight times to date. And, actually, we have another meeting scheduled for next week.

And the purpose of the Executive Oversight was it looks at all the various aspects of the project both from safety analysis and technical items that we're discussing today, but also from the standpoint of how do we implement these items from outage management, that type of thing.

The Executive Oversight included a lot of experience, former NRC management and industry management experts. And they were actively engaged. To a certain extent you can almost correlate this to like an NSRB, Nuclear Safety Review Board concept for this project.

And we also ensured from a Constellation management perspective, we wanted to make sure that all resources were available. And you'll hear a lot of discussion today about some of the risk beneficial changes that were being made that when we pursued this project we wanted to ensure that we weren't just pursuing it in order to obtain additional megawatts, but we also focused on what's the impact of this uprate on operations and that type of thing and could we also pursue some beneficial actions at the same time we were operating to reduce potential burden on the operators. And those will be discussed today.

CHAIRMAN DENNING: Okay. And you'll specifically identify those risk beneficial changes for us, and are they all in the procedural domain?

MR. FLAHERTY: No.

CHAIRMAN DENNING: Okay.

MR. FLAHERTY: And I think Rob will go into more detail specifically in the risk deltas and improvements and that type of thing.

So with that, I'll turn this over to Mark Finley then.

MR. FINLEY: Good morning. As Mark said, my name is Mark Finley. I'm the Project Director for the power uprate at Ginna.

In terms of my background, 28 years nuclear power, 7 years additionally in nuclear Navy. And then 19 years at Calvert Cliffs. And then the last two years I've been at Ginna as the Project Director for this power uprate.

Significantly, at Calvert Cliffs the last 13 years there I was in the fuel and safety analysis group, which is why I'll be talking about the safety analysis here the next time I come up.

What I'm going to do at this point is discuss the changes to operating parameters, the modifications to the plant to achieve the power uprate, the license amendments and the use of operating experience that has gone into the design and procedure updates for the plant.

Before I begin, though, I would like to echo the comments that Mark made about our experienced project team and specifically about the Ginna engineers that you're going to hear later today. These Ginna engineers all have significant experience at the Ginna site, perhaps with the one exception Rob Cavedo who is a corporate PRA specialist. But the other engineers are the lead engineers in their technical areas at Ginna which means not only were they familiar with the design and licensing basis for Ginna, but they're also very familiar with the operational issues and the real margin issues at Ginna. And these are the engineers that were the lead people on my project team.

One of the lessons incorporated in our project team was not to come in with a corporate project team that really had no experience at the site. We did not do that from the beginning.

And these gentlemen from Ginna, of course, are backed up by very experienced teams at Westinghouse, at Stone & Webster. And we've got a selection of those experts here today. And we're going to try to give you a meaty presentation. If we don't have the meat that you're looking for, ask the question and we'll try to get you the answer.

The first slide here I'm going to call my Waterford legacy slide. Because I looked at the transcript of your meeting with Waterford and I saw confusion about how exactly is the plant going to get the power out. And I hope to do that with this slide. If I don't, then please ask questions.

It's a little bit busy, but I'll spend some time with it.

But first of all, the first line item there core power. You see the change from 1520 to 1775 megawatt thermal. That is a 16.8 percent increase.

So you ask how do we get that power out? Really two major changes. The first is the average coolant temperature is increasing, that second line item. The average temperature coolant is increasing from 561 degrees to 574 degrees. And we do that to raise the steam pressure in the steam generator and drive the flow through the turbine. Okay. That's the first change.

The second primary change we're using to increase the power out of the plant is the ⌂T or delta h across the core. Okay. We're increasing the power out of the fuel, increasing the core ⌂T. You can see the delta h term there from 74 BTUs per pound to 87.1 BTUs per pound; that's an increase of 17.5 percent. Okay. That's actually greater than the total power increase. And the reason for that is if you go down another couple of lines you see the coolant mass flow pounds per hour. That's actually decreasing slightly, very slightly, minus 0.7 percent. That's a mass flow rate. Volumetric flow rate is actually increasing very slightly. But overall the flow is fairly constant. We're increasing the core ⌂T and that's how we're getting the power out.

MEMBER WALLIS: I think what you said is very clear. How does this relate to the table that's in the SER where there are two different ways to get the power uprate and they end up with a T_{Hot} of 615 in one of those columns?

MR. FINLEY: Right.

MEMBER WALLIS: It doesn't seem to be the same as your numbers here.

MR. FINLEY: Right. Right. And I'll emphasize that these numbers are the nominal operating parameters.

MEMBER WALLIS: They're nominal. But you can operate with other kinds of numbers which might lead to a higher T_{Hot}, for instance?

MR. FINLEY: That's correct. However, we would fully analyze any change in these operating parameters. We have control set points in the plant that essentially control the plant to these parameters. That's --

MEMBER WALLIS: But when you're doing the safety submittal which numbers then do you use? Do you use these ones or some of the numbers that are in the SER, or something else?

MR. FINLEY: The safety submittal uses the numbers in the SER. It uses the bounding safety analysis --

MEMBER WALLIS: Okay. So it uses the maximum T_{Hot}, the 615?

MR. FINLEY: That's correct. That's correct.

MR. DUNNE: This is Jim Dunne from Ginna.

Basically what's in the safety submittal is the range Tavg that the plant has been designed for.

MEMBER WALLIS: Right.

MR. DUNNE: So now from an operation point of view we have to stay within that band. So the Tavg is chosen we look at the present condition of the steam generators, the present fouling factor. We look at basically the inlet pressure that we're designing our new HP turbine to and we basically have to figure out with the frictional loss in our system what pressure we need back in the generator to get that flow to the turbine to reach full power.

The secondary side pressure in the generator then defines your T sat. And then we figure out what Tavg we need based upon the present plant conditions to basically get that power across the generator tubes to --

MEMBER WALLIS: And during a fuel cycle you might change these parameters?

MR. DUNNE: No.

MEMBER WALLIS: No?

MR. DUNNE: Typically when we replaced the generators in 1996 we designed the RCS and the replacement for a Tavg window from 561 to 573½. Our original steam generator, our Tavg prior to replacement have always been 573½ but our operating experience had shown with plugging of the generators due to defect mechanisms, steam generator pressure fell off. And prior to replacement we were running valves wide open on our turbine at reduced power level because were volumetrically flow limited by the turbine basically. So when we did the replacement, we decided: (1) we'd put in steam generators to have that greater surface area than the original generators, and we decided we wanted to have a band -- we wanted to analyze the plant for a Tavg window so that we could adjust Tavg as we needed to support any degradation in steam generator performance, i.e., plugging as we went along.

We choose 561, which is at the bottom range of the Tavg range, that we had analyzed for 1996 as our operating point at that point in time. And that's the Tavg we have operated at from 1996 to the present. We haven't seen any degradation in the steam generator performance and basically we have had to plug very few tubes. So there has been no need for us to adjust Tavg from cycle-to-cycle. If we basically saw we had to start plugging tubes and we were basically going to valves wide open on the turbine and we become power limit, then we would evaluate changing the Tavg for a future cycle. But that Tavg that we would change would have to fall within the 564 to 576 Tavg range that we've evaluated for the operate rate.

So for the present operating conditions we are choosing a Tavg coming out of our refueling outage of 574 to basically get us to the full power condition with the new turbine.

MEMBER WALLIS: And when you're looking at the conditions in the head if you're evaluating the life of the head and the --

MR. DUNNE: We are addressing that.

MEMBER WALLIS: -- various things that could happen --

MR. DUNNE: We use the upper band.

MEMBER WALLIS: -- you'd use the maximum--

MR. DUNNE: Yes.

MEMBER WALLIS: Do you use --

MR. DUNNE: All the analyses that were done for the uprate project would either use the minimum or the maximum Tavg, minimum or maximum T cold--

MEMBER WALLIS: Whatever is --

MR. DUNNE: -- whichever was conservative for the particular set of the analyses.

MEMBER WALLIS: Okay.

MR. DUNNE: Once we do that, now we need to make sure we operate the plant within that band, we're choosing a Tavg coming out of the uprate outage of 574 to get to the power level, our license power level. And based upon past experience, we've gone ten years with 561 with no need to change it.

MEMBER WALLIS: So some of these things are based on the conservative limit?

MR. DUNNE: Right. I think that's --

MEMBER WALLIS: But when you get to the LOCA, it seems to me you're using a statistical method.

MR. DUNNE: Right.

MEMBER WALLIS: You're using the best estimate, which presumably are these values with some variation around it?

MR. DUNNE: The best estimate LOCA would use -- I think Westinghouse is in a better position than I to answer that. But they would use a conservative value with statistical uncertainty. I don't think they used our nominal Tavg. They used a normal design band for doing the best estimate.

MEMBER WALLIS: Because when you get near some limit and the margin begins to disappear, it makes a difference which one of these numbers you choose to put in your analysis.

MR. DUNNE: Well, in theory since we've done the analyses between the min and the max, we should be able to operate the plant at any Tavg within that window coming out of our uprate. And our determination as to where we need to operate is the 574 number.

I think what happened with Waterford is they were combining design numbers with operating numbers, which is very confusing. What we're showing here is a best estimate as to where the plant is operating today for pressures and temperatures and flow and where we expect the plant to operate coming out of our refueling outage. And that should be within the band of temperatures that were shown in the licensing report.

MEMBER SIEBER: I have a couple of questions just to clarify some things in my own mind.

Your original steam generators were model 44?

MR. DUNNE: That's correct.

MEMBER SIEBER: What's the square foot of the replacement steam generators?

MR. DUNNE: The originals were model 44, so they had 44,000 square feet. The replacements were B&W Canada replacement we have 54,000 square feet. So they're comparable to a Series 51 generator.

MEMBER SIEBER: Okay.

MR. DUNNE: Which is what basically Kewaunee had.

MEMBER SIEBER: With the allowance for 690?

MR. DUNNE: Right. The other change we made when we replaced the generators is we went from Alloy 600 to Alloy 690. Alloy 690 has a slightly lower thermal conductivity.

MEMBER SIEBER: Right.

MR. DUNNE: Which gives you little bit more hydraulic consistency --

MEMBER SIEBER: Three percent.

MR. DUNNE: -- and to gooseup the surface a little bit to compensate for the lower thermal conductivity.

MEMBER SIEBER: Now the next question I looked through the list of things that you changed in the plant to accommodate the EPU. Could you describe for me what steps, if any, that you took to evaluate that the size of your pressurizer, which you aren't replacement, is adequate for the uprate of power?

MR. FINLEY: Yes. I'll do that specifically in the safety analysis area where we discuss the results of the events that essentially result in the sizing of the pressurizer.

MEMBER SIEBER: Okay. Well, one of the key questions there is at a plant trip from full power, where does the pressurizer level go? And if the pressurizer is sized for a lower specific power level, there is a chance that it would go below a good operability limit and perhaps get a steam bubble in the head if you emptied the pressurizer altogether. And so I'm curious to hear more about that.

Now, I understand that you have selected within a range of parameters. Your tech spec change puts in the limits for all of these parameters, but you expect to operate with some margins below those. On the other hand there's nothing saying that you couldn't operate at the limit, which in my view puts T_{Hot} at 517, perhaps. And --

MR. DUNNE: 617.

MEMBER SIEBER: And the INCONEL 600 question then pops up that basically says there is some kind of a transition point at 611. You would be beyond that if you used all of your margin and operated, for example if you had a lot of steam generator tube plugging, you may be T_{Hot} but it is beyond that. So the question becomes what remaining uses in your reactor coolant system do you have for alloy 600 or weld material 8182 which potentially could be subject to cracking? And it may be buttered joints, for example, and components are welded into the reactor coolant systems. It may be in your pressurizer surge line and so forth.

The next question is the pressurizer operates at a higher temperature than any other place in the plant, basically. And so what materials are used in the pressurizer?

I note with your EPU you aren't changing any of your pressurizer parameters. They will remain the same. So you've become no more susceptible to this today or in the future than you are today. But I'm still curious as to what the materials are there and what your operating and repair experience has been with the pressurizer.

MR. FINLEY: Understand. And as Mark as at the outset, we have replaced our head in 2003.

MEMBER SIEBER: Right.

MR. FINLEY: So that resolved the alloy 600 concerns on the head specifically.

MEMBER SIEBER: Right.

CHAIRMAN DENNING: And I'd like to defer into the materials section where we discuss about other materials.

MEMBER SIEBER: Okay. I've already checked off my list of things; your head replacement and steam generator replacement.

MR. FINLEY: Good. Good. And as you mentioned with respect to the pressurizer, as you see on this slide the nominal pressure in the pressurizer is not changing.

MEMBER SIEBER: Right. So the temperature is the same?

MR. FINLEY: The temperature in the pressurizer is not changing. Right.

MEMBER SIEBER: On the other hand, the volume becomes an issue for power uprate?

MR. FINLEY: Right. Right. And so we'll touch on the volume and the sizing of the pressurizer in the safety analysis section.

MEMBER SIEBER: Okay. Thank you.

MEMBER MAYNARD: Are you at T_{Hot} or T cold head?

MR. DUNNE: This is Jim Dunne.

I believe we are basically considered to be a T_{Hot} head. Typically I think we assume that the head temperature is about ten degrees below our hot leg temperature.

MEMBER MAYNARD: Okay.

MR. DUNNE: Or T_{Hot} temperature. Yes.

MEMBER MAYNARD: Okay. And that's what I would have probable thought for your plant.

And also your steam generator 2 plugging limit, what's your current analysis based on?

MR. FINLEY: This analysis is based on a ten percent 2 plugging.

MEMBER MAYNARD: Ten percent?

MR. FINLEY: Yes.

Other questions? Good

I'd like to summarize the plant modifications. Before I go down the list, I'd like to say at the outset that the design objection for the Ginna power uprate was to maintain the overall safety and reliability of the plant at the uprated power level. And several of these modifications did just that, i.e., we didn't reduce margins with respect to operation of pumps in the feed and condensate system or cooling for the transfer or iso-phase. We maintained the operating spare configuration, if you will. And again, that maintains the overall reliability of the plant operation.

MEMBER WALLIS: So your fuel is changing with the upgrade? You have bigger rod diameter and so on. So there's a while when you have a mix of fuels in there?

MR. FINLEY: That's correct. That's correct. There'll be two transition cores. And Gordon Verdin will come up and talk in some detail on that.

MEMBER WALLIS: We'll get to that. We'll get to that.

MR. FINLEY: With respect to the modifications, the first three on this list are the safety related modifications. As you can see, the bulk of the modifications are to the balance of the plant, and this is not a surprise. Mark had mentioned the comparison to the Kewaunee plant, our sister plant, who is operating to a very similar power level. We have nearly identical NSSS systems. They've safely operated at that power level now for more than a year. So we expected with similar designs that we wouldn't need significant modifications to the NSSS.

We are changing the fuel assembly. And, again, Gordon Verdin will speak to that here shortly.

We are installing new actuators on main feed isolation valves. They're manual valves now. We're installing an air operator to automatically close these values during a steam line break scenario. We'll talk more about that with respect to the license amendment associated with it.

MEMBER MAYNARD: Okay. So you're not adding an valve into the system. You're actuator for the existing valve?

MR. FINLEY: That's correct.

MEMBER MAYNARD: Okay.

MR. FINLEY: The air actuator on the existing valve.

For the standby aux feedwater system, as you probably know Ginna has a very robust aux feedwater system overall. There's five aux feedwater pumps, two are standby pumps. And for the standby pumps the discharge valve internals will be replaced to increase the flow slightly from that pump.

Probably the largest modification for the uprate is replacing the high pressure turbine rotor. Part of that modification is to also modify the turbine control valves, essentially increasing the throat area on those values to reduce the pressure drop across the valves. Obviously what we want to do is get more steam flow to the turbine and through the turbine. We will be operating in the valves wide open mode as opposed to the sequential valve opening.

MEMBER SIEBER: This isn't a safety question, but I'm curious. In your modified turbine how many stages will be impulse stages and, I presume, everything in the high pressure turbine will be on the impulse stage or stages that is reaction?

MR. FINLEY: Let me ask Jim Dunne to answer that.

MR. DUNNE: Jim Dunne from Constellation.

Right now we have a partial arc of Westinghouse turbines. We're going to a full arc Siemens' turbine design.

MEMBER SIEBER: Okay.

MR. DUNNE: And they do not have an impulse stage. They basically have all reaction.

MEMBER SIEBER: Everything is all reaction?

MR. DUNNE: Everything is all reactionary.

MEMBER SIEBER: Okay. So you don't have the nozzle blocks and --

MR. DUNNE: No. We do right now. And if we did not replace the turbine, we would have had to have gone in and rework the nozzle on our existing turbine to get increase flow capability. Basically we went and got bids for a new HP turbine because basically the delta megawatt improvement with the new turbine design for the new uprate verses modifying the old turbine basically was favorable. And we looked at a number of different of vendors with different designs. And we choose Siemens, which is really the old Westinghouse turbine owned by Siemens. And they basically what they sell today is a full arc no impulse stage turbine, and that's what we're installing. And as part of that --

MEMBER SIEBER: But you would operate with valves wide open regardless of what it is?

MR. DUNNE: Yes. You don't really want to be fully wide open, but you basically you want to be close to wide open on your full arc machine. You'd still have a little bit of bite, and basically running full open.

MEMBER SIEBER: Okay. And you're replacing not only the rotor but the casing?

MR. DUNNE: We're reusing the existing casing. We're just replacing the stationary blades and the rotating element. The outer casing cylinder and stuff is for the existing machine.

MEMBER SIEBER: Okay.

MR. DUNNE: We are replacing the turbine control valves because with the existing control valves with the increased flow we're getting a lot of pressure drop and we're basically going to a bigger control valve flow area point of view, we would minimize the pressure drop across the turbine control valve stage. The governor, the stop valves on the turbine will stay as the existing valves.

MEMBER SIEBER: And I presume that your new control system is digital as opposed to the old one which was hydraulic and mechanical, analog?

MR. DUNNE: At this point we're basically maintaining our existing control system.

MEMBER SIEBER: Which is an analog system.

MR. DUNNE: It'll be hydraulic, yes,

analog system.

MEMBER SIEBER: Yes.

MR. DUNNE: Independent of uprate, I think there's an issue as to whether we should long term replace the digital. But that's not being done as part of our uprate. We are changing, you know, the programming and some of the cards that go into that system because of the new characteristics of the new control valve and going from a partial arc emission to a full arc emission, the philosophy.

MEMBER SIEBER: Okay. Thank you.

MEMBER WALLIS: So the low pressure turbine is the same?

MR. DUNNE: Low pressure turbine is exactly the same as we had.

MEMBER WALLIS: Do you have more extraction or you have the extra ten percent flow goes through the low pressure turbine.

MR. DUNNE: Basically the low pressure turbine was not flow limited, so basically --

MEMBER WALLIS: So all the flow's going through -- or there's a ten percent increase in flow in the --

MR. DUNNE: The flow to the low pressure turbine will increase, which is one reason why we have to make modifications to our MSR relief system.

MEMBER WALLIS: And your condenser, too?

MR. DUNNE: Condenser --

MEMBER WALLIS: Safety. Probably not --

MR. DUNNE: Right. We'll have a higher back pressure, obviously, at any given late temperature for a condenser. But we're not making any changes to our -- or system as part of our --

MEMBER SIEBER: But you have retube the condenser?

MR. DUNNE: We did retube the condenser in 1995, went from an admirality tube to basically stainless steel tube primarily to get cooper alloys out of our feedwater system because of steam generator corrosion issues.

MEMBER SIEBER: And these changes will increase the extraction pressure side of your feed heaters?

MR. DUNNE: Yes, that's correct. All the extraction pressures will increase. The one that we do have some control over with the HP turbine modification, our final feedwater heat, our high pressure heater because that comes off of the HP turbine point. And so we defined a final feedwater temperature for the uprate that Siemens is designing too with their HP turbine.

MEMBER SIEBER: Okay. So that means you have more stored energy. You may have to change relief valve settings on the feed heaters. And the other thing is that if you trip, there is more stored energy and therefore more of a propensity to go to overspeed faster?

MR. DUNNE: We --

MR. FINLEY: Right. Right. For both of those comments, the relief valves on the feedwater heaters and the stored energy for overspeed trip setting on the turbine, we've incorporated the new conditions in our analyses.

MEMBER SIEBER: And it's satisfactory.

MR. DUNNE: Yes.

MR. FINLEY: Yes. No modifications to the relief valve. We are changing the over speed trip settings slightly.

MEMBER SIEBER: Thank you.

MR. FINLEY: To continue down the list of modifications. For the main feed and condensate train, we are replacing the impellers on the main feed pumps and the motors on the main feed pumps and also the impellers and motors on the booster pumps, obviously to get the additional flow through condensate feed.

The feed regulating valve is being changed to a valve with a passing greater flow. And also the bypass valve on the feed regulating valve; the internals there are being replaced.

Cooling for some of the electrical systems is being upgraded. For example, for the main generator we're replacing the condensate cooler which cools the water into the hydrogen coolers on top of the main generator, you know for the greater I squared R losses in the main generator.

The step up transfer is getting an additional cooler bank. This is one of the modifications I mentioned to you. We have an installed spare now. It was necessary that we modified the cooling system for uprate, but we would have had to use the installed spare. We put a new cooler bank in, so we still have an installed spare.

Similar with the iso-phase bus ducts. We're adding a third fan. We have two fans now. Typically those two fans run all the time and that flow would have been adequate for the cooling. We're installing a third fan, again to provide an operating spare. For upright, we'll need to have those two fans operating whereas currently technically we would only need one fan operating.

And finally, the underground oil cables, and Joe Pacher will talk more about this this afternoon, but we have oil filled eight inch cables that run from the site transformer across the street to the switch yard. And we're instituting a forced flow of that oil system. All that pumping and piping is available now, and it's been available since the site was originally constructed. We're putting those pumps in operation at this point to circulate the oil. And that will only be required for the warm months of the year.

Moisture separator reheater relief system. As we talked about, the pressures will increase here and the flow requirements will increase. And we're making modifications to that.

There will be various heater drain minor modifications to piping, vent systems and so forth to handle the increased flow rates.

Minor support changes all in the balance of plant, and this is in response to the higher transient loads. When you shut turbines and stop valves and/or feed reg valve, those transient loads are higher and there are some beefing up of supports that will be needed.

And the finally, this will be talked about more in Rob's risk presentation, three modifications that specifically relate to risk benefits. We're adding a backup air system for the charging pumps and we're adding some controls for both the charging pumps and the turbine driven aux feed pump to help the operator response, particularly in fire scenarios.

MEMBER MAYNARD: You're talking about local controls or operating outside the control room?

MR. FINLEY: That's correct. That's correct. For scenarios where the operators need to evacuate the control room and operate these components locally.

With respect to license amendment, Pat Milano touched on these briefly, but I'd like to summarize. Obviously the important amendment relates to changing the power level, allow the core thermal power increase to 1775 megawatt thermal.

LOCA methods we are updating to the newest approved Westinghouse BE LOCA method. ASTRUM versus an older BE LOCA, SECY-83-472 method.

Axial offset control we're changing from the constant methodology to a relaxed methodology which changes the limits on axial flux distribution.

MEMBER SIEBER: Could you explain that in more detail, please?

MR. FINLEY: I'll defer to Gord Verdin if you can wait when he comes up with the fuel discussion.

MEMBER SIEBER: Okay.

MR. FINLEY: We are increasing the maximum allowed boron concentration for the accumulators and the refueling water storage tank. And that's to allow for a higher boron for the hold down reactivity at beginning of life in the core.

Minimum value in the actuator is actually reduced slightly. This is really not due to the uprate, per se, but because we were doing the analyses we got a little bit more margin for our uncertainty calculations for the level setpoints on the accumulators here. So we reduced that slightly.

MEMBER SIEBER: But you aren't going to change any setpoints? You're not going to change any setpoints?

MR. FINLEY: That's correct. We're actually not changing the level --

MEMBER SIEBER: So the levels will be the same, just more margin?

MR. DUNNE: The control that I used at ops controls the accumulator level, too, it would be the same. We're just giving them more margin with tech specs, like Mark said, primarily to accommodate to give us more instrument uncertainty margin going forward.

MEMBER SIEBER: Thank you.

MR. FINLEY: The condensate storage tank minimum volume in the technical specifications will be increased. And this is due to the basis for that tank to provide two hours of decade heat removal capability. Obviously, our decay heat will be increasing.

The feed isolation valve that we talked about modifying is actually a back-up valve to the feed regulating valve. The feed regulating valve is the primary closure that we rely on in a main steam line break. It actually closes in ten seconds. This new valve will be closing in 30 seconds. However, that's faster. You can see here twice as fast as the current valve that we have in the tech specs, which is the feed pump discharge valve.

So not only will be the valve be closing faster, the new valve, it's also closer to the steam generator down the pipe further. So that's better from the standpoint of shutting off the hot water in that pipe closer to the steam generator.

And then finally there are changes to the safety setpoints, and I'll defer to the safety analysis section and talk about each of those specifically.

And the last thing I'd like to speak to at this time is the importance of industry operating experience. This has been factored into every aspect of the project for the Ginna power uprate. I'm going to touch briefly here on a few of the topics to give you a sense of what we learned, but by no means is this a complete list.

Vibration induced failures, obviously we've understood the history of vibration induced failures throughout the industry, specifically on small bore piping. One of the things we're doing here is incorporating all of the failure points that we've seen in industry, and in fact all of the small bore piping that's tied to the large piping that will see flow increases, and made that a part of our vibration monitoring plan as we escalate the plant.

MEMBER SIEBER: The architect engineer for your plant was Stone & Webster?

MR. DUNNE: No. The original architect engineer was Gilberts. Ginna was a turnkey plant and Westinghouse was basically responsible for picking the

AE and the constructor. And for the Ginna of Ginna, they chose Gilberts.

MEMBER SIEBER: Back in the days when your plant was built the piping engineers typically did not do a rigorous analysis on supports for small bore piping, particularly a seismic analysis. They used templates and said at, you know, every 20 feet I'm going to put a hanger and it'll look like this out of their cookbook.

Have you ever gone back and reanalyzed with modern analytical tools the response and support system for your small bore piping or are you still relying on the template type of hanger design?

MR. DUNNE: For our safety related systems in the late '70s early '80s, we went back and did a seismic upgrade program, but that was I think for piping two inches and larger in general. The small bore piping we're just basically using engineering judgment for adequate supports.

Balance of plant there was no attempt to go back and redo that. It's primarily based upon operating experience where if we see support damage or something, we'll go in and analyze it to see what could have caused it and whether it's something related to design that needs to be changed.

MEMBER SIEBER: Okay. That's typically what licensees did in that period. And that leaves out things like vents and drains and instrument impulse lines. In the history of your plant have you had cracks or other failures of those types of lines; vents and drains and --

MR. DUNNE: We've had some socket weld failures. I don't think we've had a lot of them, but we've had some of them. Usually they attribute it to a construction defect that basically propagates over the operating life of the plant.

MEMBER SIEBER: Okay. But you've never had one break off? You just have cracks that caused leaks, right?

MR. DUNNE: I'm not aware in the time I've been there of any that have broken off. The one event that I am aware of is that we had a pre-separator tank fail on us in the early '90s, which was an erosion issue due to an inadequate material. And we --

MEMBER SIEBER: What was the tank again?

MR. DUNNE: It's a pre-separator. Ginna on the HP turbine outlet to the MSR inlet installed pre-separators to a decreased moisture loading --

MEMBER SIEBER: Okay.

MR. DUNNE: -- on the MSR separator, if

you will, in the mid '80s. It's a skimmer basically in the piping going towards the MSR to try and do some preferential moisture removal. The moisture that removed is routed to a tank and then gets trained to a feedwater heater through a control valve. In the early '90s we had one of those tanks fail on us due to erosion --

MEMBER SIEBER: Yes.

MR. DUNNE: -- within the tank due to an inadequate material. That's the biggest thing that I remember. We basically went in and modified all our tanks.

One of them failed, I believe we have two. Yes. And so we modified the one and then the next refueling outage we replaced both tanks with new tanks with basically upgraded materials for erosion issues.

MEMBER SIEBER: Okay. Thank you.

MR. FINLEY: And let me ask Roy Gillow audience. He's operated the plant for many years. He can speak to experience here.

MR. GILLOW: Yes. I'm a senior reactor operator. I've worked 23 years at operations. And I recall any kind of failure like you're talking to. The things we've had is impingement issues in some extraction steam lines like Jim mentioned. But never any failure of vibration induced failure of a line that I'm aware of.

MEMBER SIEBER: Okay. Thank you very much.

MR. FINLEY: With respect to the turbine, one of the lessons learned in the industry is when you go to these more efficient low clearance machines that the likelihood of rubs especially during power increase or coming up to speed and low powers increases, and one of the things we learned here was that you can't have an asymmetric lineup of your feedwater heaters on the turbine. It sets up a gradient across the turbine which can cause these rubs. So we're going to factor that into our operating process.

Turbine control valves. Again, we're going to the valves wide open mode. One lesson we learned here is that instead of having all four valves come off their shut seat when you initially come up in power and starting the plant up, is to stagger two of the valves slightly. And so we have more bite on two of the values, and the other two will lag for some period of time before they all come up together. So this will help the control issues.

Iso-phase. You're probably aware of

failures due to flow induced vibration in iso-phase bus ducts. These happened at plants that significantly increased their air flow in the bus ducts. We have a small increase in air flow, but well within what our analyzed limit is for increasing vibration in the bus ducts.

We've also carefully looked at the heat loads on the system to make sure that that flow is adequate to handle the heat removal.

Step-up transfer cooling. There have been issues for plants that didn't really understand the heat loads on their cooling system. And in particular they didn't understand what the ambient loading, the ambient air temperature was surrounding their transformers. We did a study during the hottest time of the year to verify what the ambient conditions before we analyzed the heat loads.

Power measurement. There's been issues with respect to secondary calimetric calculations in particular. And Ginna's looked at all of the inputs to the secondary calimetric calculation and verified that we have the right scaling, that we have the right ranges on all those inputs and that the accuracy won't be compromised.

And then finally with respect to operating setpoints: Steam pressure, T_{Hot}, ΔT all those have been issues. We've looked carefully at the margins there. We've used Westinghouse to optimize the margins. And we feel we have plenty of operating margin to be.

And with that, I'll conclude my first presentation.

I'd like to introduce Dave Wilson who is the licensing lead for the project to discuss the process.

MR. WILSON: Good morning. I'm David Wilson. I'm a principle engineer at Ginna Station. I've been there about 20 years.

Most notable last accomplishment was I worked on a license renewal project. I'm contributing to power uprate here.

What I'd like to talk about is RS-001 submittal, the fact that we added some additional sections, the level of staff interaction we had and the level of review effort we made. I'll be brief.

What we wanted to do was give them everything that they asked in RS-001 plus everything we think they needed based on operating experience from other utilities. And we got a lot of coaching and a lot of good interactions with the staff, so we were very pleased with that.

In order to pull the job off successfully we added some unique sections that aren't in the RS-001 document. We talked about our renewed operating plant license in every section that had an impact. We talked about the system evaluation program we underwent in 1970s and '80s and how that relates to our CLB, our current licensing program. And we gave them a section 1 to RS-001 which we considered to be a roadmap of lessons learned that allowed the staff and the station to enter the dialogue on how to relate the facts that were not designed for the standard review plan, and have opened an honest dialogue and discussions.

We met frequently with the staff. We had very timely meaningful interactions. That is, as you heard, before we had presubmittals and that allowed us to keep working on the major submittal while giving the government an opportunity to work on the long lead time evaluations.

Everywhere we had the opportunity we incorporated lessons learned.

We had no surprises in our review effort. Communications were prompt and they were very clear. And we worked through the issues.

We had a very rigorous owner acceptance review of our vendor inputs. Our acceptance reviews were proceduralized and we did get quality assurance reviews of those to make sure that we were following our procedures. And, by in large, the NRC reviews went very well. The questions that were asked were meaningful and relevant. And it was pleasurable to have a line of reasoning with RAI that came in. That really kept us from having miscommunications and delay sin the process.

MEMBER WALLIS: You had all these interactions with the NRC. Did you have some reviews from sister plant people or some sort of internal --

MR. WILSON: Yes, we did. We had --

MEMBER WALLIS: Did you find that useful? Did you get information which you wouldn't otherwise have got that way?

MR. WILSON: Oh, absolutely.

MEMBER WALLIS: All right.

MR. WILSON: And we also fostered that in the industry. We're now providing our expertise, if you will, to other utilities. You know we're trying to push the lessons learned throughout the industry. So we had principally Kewaunee was a very big help to us. And we had them up several times.

We had a sequester week where we took industry experts and our staff and our vendor experts and we locked ourselves away for a full week going over the hard issues and reviewing the operating experience and trying to make sure that we actually understood the implications of some of the operating experience that we saw in the industry, and that we correctly dealt with it.

It was a pretty rewarding project to work on. We were pleased with the interactions of the staff.

If there are no questions for me, I'd like to introduce Gord Verdin. He's our fuel lead.

MR. MILANO: We had originally planned for a break now. But we can go on.

MR. FLAHERTY: Yes. We'll go on.

MR. MILANO: I'd like to take a break after his?

MR. FLAHERTY: After that?

MR. MILANO: Thank you.

MR. FLAHERTY: That would be fine.

MR. VERDIN: Good morning. My name is Gord Verdin, I'm a principal engineer at Ginna Station. I'm the principal engineer for the primary systems and reactor engineering group. I've been at

Ginna for 9 years. In those 9 years I've served primarily in the areas of reactor engineering, steam generator engineering and also in engineering analysis.

I do have an SRO certification and I was an STA for a year and a half.

Prior to that I worked for 4½ years at Babock & Wilcox Canada as a steam generator thermal hydraulic designer and as a steam generator service engineer.

Today I'm going to talk about fuel and the core, in particular the fuel assembly design that we're going to be implementing with the EPU. The goal of this fuel assembly design was to recover and improve margins for the EPU compared to the current fuel. And also we will be adding some additional robust features that Westinghouse has implemented over the last several generations of fuel that they've made.

MEMBER WALLIS: In getting the power uprate, this means you have more fission material in the core?

MR. VERDIN: That is correct.

MEMBER WALLIS: Is it roughly proportional? Do get the same sort of burnups the new fuel?

MR. VERDIN: The burnups will be similar. We're currently we're as far as average fuel assembly, discharge burnups are approximately 50,000 megawatts days per MTU. That should be similar. The actual per fuel assembly uranium loading is going up from about 346 kilograms uranium to about 396 kilograms of uranium.

I'm going to talk about core design briefly. Some of the strategies and the number of feeds that we'll be doing. Obviously as part of this uprate, it's a fairly large uprate, we will be putting in additional feed assemblies over what we normally would for the first two cycles. Then we'll get back to a number of assemblies that's similar to what we're using currently.

And then lastly I'm going to talk about core operating limits. This is where I'll address the CAOC versus RAOC question that was asked previously.

In front of you can see the diagram showing both the current Ginna 14 by 14 optimized fuel assembly, that's the OFA. I'll refer to it as OFA from now on. And on the right side you'll see the new 422 Vantage Plus 9 grid Ginna assembly.

The significant changes that we've

implemented here are the rod outside diameter is going to be changing from .4 inches to .422 inches. That obviously gives you a larger surface area and helps to recover DNBR margin that you -- as a result of the uprate, obviously, we do need to cover margins and that's one of the way that we do that. That also, obviously supports the increase in uranium inventory that I had previously discussed.

MEMBER WALLIS: This gives a higher fluid velocity?

MR. VERDIN: Yes. The fluid velocities are higher. And what I will address is the thermal hydraulics. It seems a little counter-intuitive. When you first see it, you think that you're going to see a reduction in volumetric flow. I will address that.

The fuel rod lengths themselves will be increasing 3.6 inches and the fuel stack will be increasing 1.85 inches.

MEMBER WALLIS: And all this increase seems to be in the last little piece between grids 8 and 9, is it?

MR. VERDIN: Correct. I will address degree issue --

MEMBER WALLIS: You will address that, too. in

MR. VERDIN: -- as well momentarily.

But this rod length and fuel stack you'll see that we're actually building in additional plenum length inside each fuel rod. That plenum length helps to accommodate the additional fission gases and also the gases from burnable absorbers, the Zirc diboride obviously generates helium gas it burns up. So that's a margin enhancement to increase the plenum length.

The other thing is the increased fuel stack. By increasing 1.85 inches you obviously also reduce your linear heat generation rate for a given power level. So it does give you some margin in terms of central line temperatures and that sort of thing.

One of the things you can see as a result is the top nozzle for our fuel will be changing. The current 059 grid assembly has a unique -- I believe it is now unique, there was nobody else that was using that anymore. We will be going to the standard Westinghouse top nozzle, which is the shorter top nozzle that's pictured.

MEMBER SIEBER: During a couple of cycles you'll be operating with both types of fuel?

MR. VERDIN: That's correct. For two cycles.

MEMBER SIEBER: When I look at those from a seismic standpoint, the grid straps are supposed to align to give you lateral support. On the other hand in your operated fuel assembly the top strap does not have a counterpart for support?

MR. VERDIN: That's correct.

MEMBER SIEBER: Has that been analyzed and is that satisfactory from the seismic standpoint?

MR. VERDIN: Yes. Originally we are a nine grid assembly, which is unique as well. Most Westinghouse assemblies including the other 422V+ products that are out there are seven grid assemblies.

Originally we even looked at potentially going to a seven grid assembly. But overall, you could not make this work with the grid assembly -- or the grid height mismatches that you would.

Early on in the project during the implementation of this or the design and conceptualization phase, there was a lot of discussion as to whether we put those two grids such that there is some overlap, that's the top grid I'm referring to, or whether we go this way.

MEMBER SIEBER: Yes.

MR. VERDIN: There's really benefits and detractor from either approach. If you put them, obviously, in a line that you get better, there's less cross flow at that grid because obviously grid height mismatch is also a source of crossflow. If you actually look at it, it can exacerbate crossflow.

The disadvantage is that you would have to put that rod or that grid so far below the top of the rod that you have a long length, and that turns out to be a sensitivity in terms of vibration.

In the end what was determined was they did extensive analytical analysis. We've also tested these two assemblies next to each other at substantially higher flows. And the results of the testing and the results of the analysis really indicated that either approach would have worked. However, this approach for the long term once we get to cores that are all 422V+ is superior.

MEMBER SIEBER: Now the purpose of the testing that you did, was that to evaluate and learn about the degree of mixing or to look at the strength of the assembly and the seismic characteristics, or both?

MR. VERDIN: There were multiple types of tests.

MEMBER SIEBER: Okay.

MR. VERDIN: There was testing, the original testing is what's called the FACTS loop, which is basically you put the fuel assembly by itself in the loop and you pass flow through it. It's used to validate hydraulic design aspects, pressure drops, that sort of thing.

There's also what's called the VIPRE test. And the VIPRE test is where you actually put an OFA fuel assembly next to one of the new fuel assemblies. And they run it for an extended period of time, several months, at higher than design flows. They have a whole bunch of various things to look at individual rod vibration, fretting; that sort of thing. Looking at compatibility.

MEMBER SIEBER: Yes.

MR. VERDIN: And then there's other testing specifically what you're referring to,which is the seismic. There's grid crush testing --

MEMBER SIEBER: Right.

MR. VERDIN: -- on individual grids where they heat the grids up to operating temperature and then they basically put enough energy into them to verify that they're adequate.

As far as seismic design, the fuel assembly was designed for LOCA plus SSE. One of the licensing basis, things that will be discussed later, is the changing to the leak before break to limit the size of different breaks that can occur. And under those conditions, under the licensing basis LOCA SSE there's at least a 50 percent margin. Approximately half of the allowable loading was what was calculated in a mix core, in a transition core.

MEMBER SIEBER: A couple of other questions.

MR. VERDIN: Yes.

MEMBER SIEBER: The grids themselves, the support for the rod is brought about by having to dimples that are at adjacent corners, two springs.

MR. VERDIN: That's correct.

MEMBER SIEBER: With a larger rod that means you have to reduce the size and defection of the spring. Does that change the stability at all?

MR. VERDIN: Like I said, there was testing done where they put the 422V+ and OFA together. They run them at substantially higher flows than they will see in the reactor to determine the stability, to look at threading. And the 422V+ design with the larger dimples that we have, that we're going to be having with this new fuel, showed excellent fretting capability, which would obviously indicate that you have adequate holding force.

MEMBER SIEBER: Okay. Now the grid straps have little tabs and vanes and wings in order to promote mixing?

MR. VERDIN: That's correct.

MEMBER SIEBER: And it seems to me that you have a smaller overall cross section, smaller footprint here. So I would expect the flow to be less, but I think you said the flow is greater. Does that mean you sacrificed in the tabs and vanes and wings in the mixing area?

MR. VERDIN: What we have done is we have gone to a new grid design that has thinner straps. The thinner strap design, basically the reduction in pressure drop at the grids, offsets the increase in pressure drop due to friction along the fuel rods. So, yes, the straps are thinner. The straps themselves went through what's called a VISTA high-frequency test where they basically looked at fatigue of the straps and that sort of thing and determined that the straps were adequate for the design.

Also, this is obviously similar to designs that are in service. The 422V+ has seen three cycle service at Point Beach. I believe it was put in at Point Breach in 1997. And it has been discharged and it has had satisfactory experience.

One of the changes we did make to the

grids I should mention is we have gone to a balance vane design.

MEMBER SIEBER: Okay.

MR. VERDIN: The 422V+ product that's in service right now, it does not have a balanced vane design. And as a result, that potentially can be resonately self excited because it has a net force. The balanced vane design actually rotates the vanes in the four quadrants of the grid to reduce the net force. And we have implemented that. That's a robust features that's implemented from previous Westinghouse designs.

MEMBER SIEBER: Okay. Now the grid straps made out of Zircaloy?

MR. VERDIN: No. The replacement grid straps will be made out of ZIRLO.

MEMBER SIEBER: ZIRLO.

MR. VERDIN: It's a --

MEMBER SIEBER: All except for the springs?

MR. VERDIN: No. The springs are part of the grid. They're stamped in it.

MEMBER SIEBER: Oh.

MR. VERDIN: The only grids that are not, there's alloys --

MEMBER SIEBER: You're not worried about the spring relaxing due to irradiation?

MR. VERDIN: There is spring relaxation as a result of irradiation, but that's evaluated as part of the test. And on the test --

MEMBER SIEBER: So it still work at the end of life?

MR. VERDIN: -- because we don't irradiate it.

Pardon?

MEMBER SIEBER: It will still work at the end of life? It maintains contact all the way to the end of life?

MR. VERDIN: That's correct. I don't remember the criteria. I think it might be one pound that it's supposed to be maintained.

MEMBER SIEBER: Well, if you don't do that, it'll fret and then you got a damaged fuel assembly.

MR. VERDIN: Right. Right. And like I said, there is 422V+ product has been irradiated for three cycles and discharged with adequate service history. No known failures.

MEMBER SIEBER: Do you have any idea as to how big a particle, an impurity particle would be that would still make it through the fuel assembly without getting snagged on a grid strap or caught in between two rods, or captured someplace in order to block the flow?

MR. VERDIN: The Ginna --

MEMBER SIEBER: For example when you're in recirculation.

MR. VERDIN: Right.

MEMBER SIEBER: And you're pumping gravel through your system.

MR. VERDIN: Right. As far as the Ginna fuel design, we do have a debris filtering bottom nozzle. We've had that for some time. I believe the holes in the debris filter bottom nozzle are .23 inches. I remember looking at it a few weeks ago, that's the number that sticks in my head.

But if you look, the actual bottom nozzle will filter.

MEMBER SIEBER: Okay. So the debris -- well, that prevents you from getting debris up in the fuel and vibrating and making a hole. On the other hand, all the debris could go to that bottom nozzle and block it.

MR. VERDIN: Correct.

MEMBER SIEBER: Has that been evaluated?

MR. VERDIN: That is currently -- Ginna is implementing an active strainer design --

MEMBER SIEBER: Yes.

MR. VERDIN: -- that's going to be installed during our 2006 outage.

MEMBER SIEBER: An active strainer?

MR. VERDIN: That's correct. I think we'll be the first plant to implement an active strainer.

MEMBER SIEBER: You'll be one of four, yes.

MR. VERDIN: Yes. That's being evaluated as part of the downstream effects analysis. I haven't been really involved in that, so I'll have to defer to--

MEMBER SIEBER: What part of your strainer is active? What does it do? Scrap or --

MR. VERDIN: What it's got is it's too large boxes. I believe they're about three feet square. And on top of them they have a comb and sweeper design with a motor that obviously sits up high enough as to not be potentially impacted by the water level in the containment at that point. And they basically have from those large boxes that are perforated and have the perforated top, there's perforated pipes that go over to the sump. The sump itself will be sealed. The current sump such that all water has to go through this strainer mechanism.

MEMBER SIEBER: And that will receive emergency power?

MR. VERDIN: Yes, that's correct.

MEMBER SIEBER: Safety grade power.

MR. VERDIN: Correct.

MEMBER SIEBER: Okay. Thank you.

MEMBER MAYNARD: A quick question on the PLV. There's been a number of fuel failures in the industry associated with new fuel designs supposed to improve overall fuel design. Is this a new design or do you have unique aspects for your new fuel or is this a proven --

MR. VERDIN: This is based upon a proven design, which is the 422V+ that's currently in service. I believe the lead plant was Point Beach. I think it was 1997. So it has seem full -- a full irradiation for three cycles and it has been discharged. It's also now in use at Kewaunee.

The changes that we have versus those plants, obviously we have the nine grid design versus the seven grid design. We talked about swapping over to a seven grid, couldn't make it work.

The other features that we've got that

they don't have, I actually will get to them a little bit, but basically they're things like the balance vane design. That's a robust feature. That's something that we added to improve our fuel assembly over their fuel assembly based upon other robust fuel designs that are in service.

We've also done a couple of other things to our fuel. We increased the rod length .2 inches; that's to provide additional plenum volume, more margin for rod internal pressure issues.

We also when we first went down the path of this fuel transition, we were going to use an identical fuel rod design to those plants. However, because of rod internal pressure it was decided that we would remove pellet from our fuel stack to get this 143.25 inch fuel stack.

So there are slight differences, but in general it's very similar to that project.

MEMBER MAYNARD: I would caution because sometimes some very minor changes that were supposed to improve turns out to create an unexpected problem, too.

MR. VERDIN: Right. Okay. Thank you.

MEMBER WALLIS: Is this a fairly simple fuel design or is it one of these custom tailored things that has varying enrichments at different places and all that?

MR. VERDIN: No. This fuel assembly design has within the fuel assembly itself other than the axial blankets at the top and the bottom, it has a common enrichment, okay?

MEMBER WALLIS: It's uniform? Okay.

MR. VERDIN: That's correct. It has 2.6 percent min. enriched annul or axial blankets. We have annul or axial blankets to provide additional gas plenum volume. Again, a lot of this comes down to these rod internal issues.

The assemblies have multiple burnable absorber patterns. They can go anywhere from 16 to 64 to 100 rod burnable absorber patterns per assembly. That's core design specific. But other than that, no, it's not a particularly -- it's actually quite similar to what we have right now with the features that I've said. Okay?

One of the things I just wanted to mention briefly is the top nozzle on the 422V+ design you can see that it sits higher. That does have some impacts on our rod position indicating system and on our control rods. Currently our control rods will go out to 230 steps. The new control rod maximum will be 325 steps.

The other thing is the microprocessor rod position indicating system that Ginna has is a unique system. Because of the way it's a unique system that every 12 steps reads the end of the drive rod, we have to do some firmware changes to our microprocessor rod position indicating system. And those are in progress.

MEMBER MAYNARD: I don't know if you're going to cover this later or not, but it looked like during these transition cycles you're going to have potentially some differences in rod height indications?

MR. VERDIN: Correct.

MEMBER MAYNARD: Is that going to be handled -- I don't know how confusing that's going to be in the control room or on your system or for the operators there?

MR. VERDIN: For the first cycle, and for the first cycle only we will have either one or two banks of control rods that will be over OFA fuel. Okay? The remainders will be over the new 422V+ fuel.

What we plan to do is once we close the trip breakers, is we plan to go into bank mode, withdraw those banks, five steps, and then basically reset the rod control system such that it thinks that everything is at zero steps. That way there should really be no impact on the operator at all.

MEMBER MAYNARD: Okay.

MR. VERDIN: Other than, obviously the process of the original extraction by five steps. Okay?

MEMBER SIEBER: Have you done the core design yet?

MR. VERDIN: The core design?

MEMBER SIEBER: So you know what fuel will go where?

MR. VERDIN: We have a candidate, a likely candidate loading pattern that's in the process. one of the issues that we've had with this transition is the OFA fuel does have a small plenum length so it is more limiting from a rod internal pressure perspective.

During the last cycle we actually implemented, our core designer recommended and it turned out to be a very good recommendation, that for the 100 rod patterns that we had, that we actually go to a 120 rod pattern with a lower loading, so we had eight assemblies that were of the OFA design that had lower internal gas pressures. But that is the first cycle margin issue is rod internal pressure. And it requires that we actually put those OFA assemblies that are limiting in lower power locations and do more detailed fuel rod design.

MEMBER SIEBER: I presume you operate or design the core with a low leakage pattern?

MR. VERDIN: That's correct.

MEMBER SIEBER: The assemblies that will contain rods that operate at the bite level, I take it all those will be new assemblies?

MR. VERDIN: I don't understand. Are you referring to --

MEMBER SIEBER: You have some rods inserted sort of partially?

MR. VERDIN: Yes, we maintain --

MEMBER SIEBER: So you can control it?

MR. VERDIN: We maintain control bank delta very slightly inserted in the core. It's the only thing --

MEMBER SIEBER: That would be all new fuel assemblies?

MR. VERDIN: No. Actual delta will be OFA fuel assemblies.

MEMBER SIEBER: All OFA fuel assemblies?

MR. VERDIN: That's correct.

MEMBER SIEBER: Okay.

MR. VERDIN: We're actually looking at other things. It's really beyond up the uprate. It's RCCA life. We're looking at potentially operating control bank delta out of the core in the future; something we're assessing.

MEMBER WALLIS: Now you need more boron to control the initial reactivity? You need more boron in the cooling system?

MR. VERDIN: Yes. The RCS boron will increase slightly.

MEMBER WALLIS: All right. Does this have any effect on the spent fuel pool, this new fuel?

MR. VERDIN: This fuel that we're putting in is actually this 422 .422 inch rod design is actually very similar to the fuel that we used in cycles one through seven. We had Westinghouse standard fuel.

MEMBER WALLIS: Yes.

MR. VERDIN: In cycle eight we transitioned to another fuel vendor for a period of time. The original fuel was .422 and from a reactivity perspective it's actually -- it's been assessed. It's in our current spent fuel for criticality analysis this size of fuel rod with enrichments up to five percent.

MEMBER WALLIS: You have a huge margin as I understand anywhere in the spent fuel pool for criticality.

MR. VERDIN: We have in our spent fuel pool several regions. We have two regions that have borated stainless steel racks that were installed in 1997. We have older regions that are borallex racks, which are no longer accredited in the criticality analysis. That requires credit for cellular boron. We do that by checkerboarding. It's a burnout versus years of decay pattern. But that's all been assessed and it's bounded by the current standard fuel that's in the spent fuel pool.

MEMBER SIEBER: You have a maximum limit on new fuel enrichment based on your spent fuel pool design, I take it?

MR. VERDIN: Yes. We do not exceed five percent. Typically it's 4.95 with Westinghouse uncertainties.

MEMBER SIEBER: And you will meet that with all anticipated future core designs?

MR. VERDIN: We will not load a core with higher enrichment than that.

MEMBER SIEBER: Okay.

MR. VERDIN: Okay?

MEMBER SIEBER: Thanks.

MR. VERDIN: As I mentioned, some of these slides were obviously done because of the questions that have come through, but this nine grid design is based on the fuel proven seven grid design. The balanced mixing vanes that I mentioned is a robust feature. The increased dimple contact area are designed to reduce wear rate and provide more margins in the fuel assembly.

Another change that we're making is to what's called tube and tube guide thimbles. This is another robust fuel assembly feature that we're going to be implementing in our fuel. This design is actually a more rigid guide thimble that's designed to -- it's actually simpler to manufacture than the double dash pot, but it also provides additional margin against burn up induced bowing that can cause incomplete rod insertion in the fuel.

And I mentioned these other things, so I'll continue.

I also mentioned the testing. This is not all of the testing. I mentioned grid cross testing and that sort of thing, but there is the FACTS loop that was done to validate the hydraulics for the assembly, the ⌂Ts, that sort of thing.

The VIPRE was the long term wear test of the optimized fuel assembly adjacent to the 422V+ assembly. That was looking at things like cross flow and wear. There's an extensive wear testing done in this fuel assembly.

And lastly, the VISTA high-frequency testing for the straps that I mentioned previously.

As far as the core design is concerned, we've already discussed we will have two transition core cycles that contain the OFA fuel assemblies. The probably feed assembly quantities are listed. For the first cycle, which is cycle 33 which will start in November of 2006, we're anticipating 53 assemblies will be required. There are 121 assemblies currently and in the future in the Ginna core.

The 52 -- just because it's a 121 assembly core, we have a center fuel assembly. So you can see when you look at these numbers anywhere there's an odd number means the center fuel assembly will be replaced.

The first cycle 53, then we'll be doing 48 assemblies projected currently in cycle 34, which is the second transition cycle. And then once we get to the equil, all 422V+ cycles will basically be oscillating between a 45 and a 44 assembly reload.

The 45, obviously, we'll be replacing the center assembly every other cycle.

MEMBER SIEBER: I take it even though you're using a type of low leakage loading pattern that the overall, the fluence to the reactor vessel will increase for the power uprate?

MR. VERDIN: Yes. The reactor fluence will increase compared to previous low leakage core designs.

MEMBER SIEBER: Okay.

MR. VERDIN: If you were to actually look at things like outside of the vessel, the concrete, the supports; the actual fluence that's leaving the vessel is less than the original out/in fuel loading fluence that's out there. So we still remain bounded by the original plant analysis.

MEMBER SIEBER: Okay.

MR. VERDIN: Okay?

MEMBER SIEBER: That would have been my next question.

MR. VERDIN: Okay.

MEMBER SIEBER: Thank you.

MR. VERDIN: All right. Lastly, as I mentioned or was previously mentioned, the EPU analyses were done for a range of temperatures from

564.6 to 576°F for our average RCS temperature.

The reload designs it has been decided, we made this decision several months ago based upon the turbine design and sensitivity information from the vendor that we would use 574°F to satisfy the requirements that Jim Dunne previously discussed.

Lastly, core operating limits. As was previously mentioned, our axial power distribution technical specification we'll be transitioning from the constant axial offset control methodology to the relaxed axial offset control methodology. The reason for this transition, this was predominately done and I'll put some figures up in a moment to show you what it really means, we were concerned when we first started on the uprate transition at the possibility of a crud induced power shift situation. Similar has occurred at several other Westinghouse plants.

Crud induced power shift is basically in plants that have a very high massive operation rate off he fuel. Can tend to actually concentrate boron in the crud at the top of the core. It can suppress the power distribution down. Has various challenges to things like shutdown margin.

One of the challenges that we were anticipating if we did get crud induced power shift was the CAOC methodology that we currently have in our tech specs really requires us to very tightly control axial offset. If we do not control or if we cannot control axial offset within the narrow band, we basically get into what's called the accumulation of penalty time due to the build in of abnormal Xenon power distributions. Xenon and power distributions.

We were concerned the way our current tech specs are if we accumulate one hour of penalty time, that means if we cannot maintain it within this tight band for one hour, we basically are forced to go below 50 percent power for 24 hours that allows you -- and get back in the band and reestablish the correct Xenon power distribution.

We were concerned because one of the issues with crud induced power shift is during when you do down power maneuvers, the boron tends to come out of the crud and the power distribution then shifts rapidly to the top of the core. It can actually challenge your insertion limits on your rods to maintain the flux down.

We were concerned at the time that we may be subjected to CIPS and that we basically made this as a mitigating strategy to help the operators and to basically prevent this enforced -- tech spec enforced down power.

What we have done, I have contacted Kewaunee who is now near the end of this first uprate cycle at 1772 megawatts thermal. They have seen no evidence whatsoever of CIPS. So we're thinking that the RAOC transition, obviously it still buys us operational margin otherwise. But it appears that we will not be inflicted with CIPS. And I really hope we're not, because it will not be a nice issue to deal with.

MEMBER SIEBER: Sounds like a hockey game.

MR. VERDIN: CIPS.

MEMBER SIEBER: In the penalty box.

MR. VERDIN: Yes. I can actually show you that real quickly here. Just give me a moment.

MEMBER MAYNARD: Yes. I wouldn't be overly optimistic until you actually operate it and see it. Because I've been experienced with identical plants, one having it and one not. A lot of it depends on past chemistry, just a number of different things that feed into that.

MR. VERDIN: Right. Right. We have implemented some other changes. We have implemented changes to our operating procedures to put the 60 gallon per minute let down orifice in service at the time of any power changes.

One of the real reasons with CIPS is if you actually look at the analytical methods that are used to predict CIPS, they're not -- I don't have a lot of faith in them. So basically our analyses said that we originally said that we would not have or we would be subjected to CIPS. Then the analysis said we wouldn't. The difference was a small amount of carried over crud that was used in the codes. It's really something, I agree, you cannot say for sure that you won't get it.

Just to give you a real quick -- if this mouse works. This shows you just very briefly what the difference is between the two methodologies.

On the left you see the constant axial offset control methodology. You can see there's a green line which represents a target line. It represents really where the core wants to be at an all rods out condition. Then you have two red lines plus or minus five percent axial flux difference either side.

We have to try to maintain flux between those two red lines. If we get outside of the red lines, we're basically into above 90 percent power, the large black doghouse. You end up having to get back in the red lines. There's no penalty time. It's a tech spec requirement or you have to get below 90 percent power.

Below 90 percent you accumulate penalty time anywhere between the black bounds and the red. And if you're outside the black bounds, you're in violation of the tech spec.

On the right you can see the relax axial offset curve. You can see the doghouse now is really your operating limits.

I've shown a green target line in there still because it's important to understand that with RAOC we're still going to operate according to the CAOC methodology. So our operating strategy, the operators will still have a target, we'll still want them to maintain the axial flux difference on that target line. It's just that now if they can't it due to a CIPS type event, they can actually operate within the larger bounds.

CHAIRMAN DENNING: How did you actually perform this control to keep it within the target?

MR. VERDIN: The control is performed basically during any type of a down power maneuver. You are using rods and boron. So what it comes down to is you have to basically balance what you're going to use to keep the rods in a position to keep the flux where you want them to be. So basically the control is done by typically rules of thumb. We have rules of thumb at power levels where the rods have to be for various flux differences. We have recently implemented more advanced codes within reactor engineering that can help us do better predictions for the operators for these vents.

MEMBER MAYNARD: I would assume that typically for a down power maneuver reactor engineering would be involved with how much rod versus boron changes in order to maintain?

MR. VERDIN: That's correct. That's typical. Our operators actually can use the rules of thumb during rapid down powers when reactor engineering is not in the control room. But, yes, typically we would be involved for any planned down power.

Okay?

Core operating limits. As I mentioned, the CAOC to RAOC transition. One other things about CAOC to RAOC is that we are really trading off analysis margin for operating margin. So in reality when you're operating at your RAOC limits, you are more limiting than you would be during CAOC. That's obviously a decision to really make that tradeoff, basically to a much more complicated analysis in order to provide yourself with additional operating margin.

There are no changes to the thermal design flow for the core. The actual volumetric flow, it's been already said, that it will increase marginally. This fuel assembly does have a lower overall pressure drop.

The actual -- Mark mentioned previously as well, the mass flow does decrease slightly. That's just due to density changes.

The nominal 100 percent rate of thermal power, heat flux hot channel factor will increase from its current limit of 2.45 to 2.6. This 2.45 currently is because of PCT and the SECY LOCA method that we have right now. The 2.45 limit was established for the new best estimate LOCA with automated statistical treatment of uncertainty methodology. Does support the change to 2.6 and all the non-LOCA analyses do as well.

The nominal 100 percent enthalpy rise hot channel factor will be decreasing slightly from 1.75 to 1.72 in the 422V+ fuel. This is one of those margin recovery things. Obviously, with the higher powered fuel, we go to a larger diameter rod, we also bring down the F ⌂h to improve DNBR margin.

The optimized fuel assemblies themselves will have a lower limit due to the transition core penalties. When you put this lower hydraulic resistent fuel assembly next to the older OFA higher hydraulic, what you can do is you'll actually do have cross flow from the higher resistance assembly into the lower resistance assembly. As a result, the OFA limits have to be lower.

And the last thing is the shutdown margin requirements that we have will be reduced. Mark mentioned previously the addition the of a new feedwater isolation valve. That feedwater isolation valves allows us to, in the event of a normal feed reg valve closure failure, that normally closes in 10 seconds. Currently the feed pump discharge closes in 60 seconds. That tends to lead to more water being pushed into the steam generators. The required higher shutdown margin with the current design in order to limit the mass and energy release rate and the return to power. So our shutdown margin requirements will be reduced to 1300 pcm from current end of cycle of 2400 pcm.

MEMBER MAYNARD: So which one of these are you taking credit for in your analysis? Is it the main feed isolation in 30 seconds or the feed reg valve in ten seconds?

MR. VERDIN: We do not credit the feed reg valve. It is the -- Mark might be able to add more to this. But the ten second closure of the feed reg valve is the one that we would expect to occur. The 30 second is what we actual credit the analysis.

MR. FINLEY: Gordon, this is Mark Finley.

Gordon is speaking of the limiting analysis. We credit both in the safety analysis, both the feed regulating valve and the new feed water isolation valve. But for a failure, we have to consider single failure of that feed regulating valve, the faster stroking valve. In that case in that analysis we take credit for the new actuator closing.

MEMBER MAYNARD: Okay.

MR. FINLEY: Okay.

MR. VERDIN: And I'm going to introduce Mark Finley again who was just up here. He's the project director again. He's going to be discussing safety analysis.

CHAIRMAN DENNING: That will be after the break.

And are there any questions on the core before we move on? Okay.

In that case we will now take a 15 minute, which means that we'll start up again at 10:20

(Whereupon, at 10:04 a.m. off the record until 10:20 a.m.)

CHAIRMAN DENNING: Proceed please.

MR. FINLEY: Okay. Thank you.

Mark Finley. I mentioned that I was in the safety analysis group at Calvert Cliffs. That does not make an expert in the Westinghouse safety analysis methodology, little different from combustion engineering methodology under Westinghouse. But I do have the experts or a representation of the experts from Westinghouse in the audience. So if you have questions that go beyond my knowledge, I won't hesitate to call on them.

What I'd like to talk about is the changes to the safety setpoints. I mentioned under the license amendment section that there were various safety setpoints that are changing. I'll talk about those.

I'll also talk about the control setting changes.

Talk about the methods that are changing in the safety analysis area.

And then I'll talk about results from LOCA/non-LOCA containment and dose assessment and provide a conclusion.

First, the safety setpoints that are changing. These are the setpoints in the technical specifications. I'll go down the list briefly here. If you have questions stop me.

For the high flux trip we are reducing that.

Oh, by the way, these are the analytical setpoints, i.e, the setpoints that Westinghouse would use in their safety analysis. The actual field settings are bounded by these analytical setpoints. But the analytical setpoint is being reduced three percent. And what that does is provide us a more responsive high flux trip for certain of the over power transients.

Both the steam line hi-hi isolation and the steam line hi isolation settings, which are based on steam flow, are being increased. And that incorporates or allows us to increase our steam flow.

The limiting safety setting for the lift setting for the pressurizer safety valves is being reduced by two pounds from 2544 psig to 2542 psig. Essentially driven by also load analysis. I'll talk about those results in a second.

MEMBER WALLIS: You can actually set it as accurately as that?

MR. FINLEY: The tolerance in our setting of the safety valves is plus or minus one percent. And --

MEMBER WALLIS: One percent on -- a change of 2 psig is within your tolerance?

MR. FINLEY: That's correct. The actual field setting is more than one percent below this analytical limit. So we incorporate the field setting tolerance under the analytical limit.

The next two set points actually were not required for EPU, but again similar to the setting we discussed previously. Because we were redoing the analysis for EPU, we wanted to get some additional margin to support instrument uncertainty calculations. But we are reducing the safety injection setting on the pressurizer pressure from 1715 psig to 1700 psig. We've incorporated that in the LOCA analysis.

And similarly, although in the opposite direction, we're increasing the containment spray setting from 32.5 psig to 33.4 psig. Small change. Again, that one pound margin is utilized in our uncertain analysis.

And lastly --

MEMBER WALLIS: And what's your

containment design pressure?

MR. FINLEY: I'll show that on the subsequent slide. The containment design pressure is 60 psig.

Finally. the P-8 permissive setpoint, which is the setpoint above which you'll have a reactor trip on low flow, has been reduced from 50 percent to 35 percent. One of the reasons for the fairly size change here is we're using the updated and more conservative methodology from Westinghouse to establish this permissive setpoint.

With respect to the control settings, these are the control systems, the most significant control systems that are fed into the safety analysis. The full power and zero power setting for pressurizer level, at the top there you see there 56 percent for the full power setting. Twenty percent for the zero power setting. That's an expansion of the range compared to what we have now, 50 and 35. However, these ranges that we're going to for EPU are very similar to what we had prior to replacing the steam generators. As you recall, we mentioned back in 1996 we actually had an average coolant temperature that's very close to what we'll have for EPU. And the program level in the pressurizer was essentially the same as well. So we're going back to that control regime.

Average coolant temperature, we talked about --

CHAIRMAN DENNING: Now help me again on the pressurizer level. What happens at 56 percent? Is that a trip.

MR. FINLEY: Okay. No. This is actually the steady state control level. So this would be the nominal expected level at full power, 56 percent in the pressurizer.

CHAIRMAN DENNING: Oh, I'm sorry. I see.

MR. FINLEY: And then as you come down in power in a controlled fashion, the pressurizer level would program down as well.

Average coolant temperature mentioned, 574 for full power, ramp down to 547 at zero power. That's the same zero power setting as what we had previously.

We have reduced the gain setting for rod control on a power mismatch. We typically operate in automatic rod control. And if you have a power mismatch setup beyond a certain point, you'll drive the rods. We actually reduced the sensitivity, if you will, on this system so that they won't drive as fast or as far on a given power mismatch. And that was actually driven by rod drop analysis in the safety analysis.

MEMBER SIEBER: Do you find running in automatic for rod control gives you a lot more rod motion than if the operator did it manually between elements that you had administratively set?

MR. FINLEY: Yes. I'm going to defer to Roy Gillow, our operations expert, to answer that.

MR. GILLOW: No, we really don't have any rod shattering type problems or typically we don't get any steps at all in the automatic rod control at stay state or close to stay state. We've had some hot leg streaming issues, and that isn't enough to give us a rod motion even.

MEMBER SIEBER: Thank you.

MR. FINLEY: With respect to steam dump modulation, one of our objectives throughout the analysis was to maintain the Ginna capability to ride out a 50 percent load rejection, a fairly sizeable power mismatch from our design perspective. And to do that we needed to essentially increase the response for the steam dump system. So as you can see here the temperature range over which the steam dumps would fully modulate has been reduced as far as the power mismatch is concerned. And that just makes that steam dump system more responsive to a load rejection.

and then finally one of our instrument modifications which we think will provide benefit with respect to operating margin is we're incorporating a 4.5 second time delay filter on our T_{Hot} indication and what that does is dampen out the oscillations that we see in T_{Hot} which are common to Westinghouse and other pressurized water reactors. You see some oscillation in the T_{Hot} indication just due to incomplete mixing as the hot water comes out of the different power level assemblies, you see different -- it's a hot leg streaming issue that Roy mentioned.

We do have some oscillations there. This filter will damper those oscillations and actually provide a stable response for the operators.

MEMBER SIEBER: That also though increases the uncertainty of the measurement, does it not?

MR. FINLEY: We factor this module in the loop uncertainty calculation, that's correct. We also factor in the time delay in the analysis as well. In other words, we model this as an appropriate time delay in the response.

MEMBER SIEBER: And the time delay, I take it, is in the range of one to two seconds?

MR. FINLEY: The time delay is in the range of 4.5 seconds, right? And that's defined that the .693 RC sort of time frame for the circuit.

MEMBER SIEBER: All right. Thank you.

MR. FINLEY: With respect to methods, I list the primary methods here. There are other methods--

MEMBER WALLIS: And someone is going to explain to me later on how ASTRUM works?

MR. FINLEY: Actually, we can take that opportunity right now. We'll start off by saying for the large break LOCA we are changing the methodology h ere. And this again was a license amendment because this method is listed in the technical specifications going from an older version of the BE LOCA methodology to the newest BE LOCA/ASTRUM method. And let me ask Jeff Kobelak from Westinghouse to discuss the new method.

MEMBER WALLIS: There's no medium break LOCA involved here?

MR. KOBELAK: No. The ASTRUM is still a large break LOCA and --

MEMBER WALLIS: Well, I mean there's another table here, it says large and small. There's nothing in between?

MR. KOBELAK: No. The large break covers down to a one square foot break.

MEMBER WALLIS: And then small is less than that?

MR. KOBELAK: I can't speak to the small break LOCA analysis.

MR. MILANO: And the answer is yes.

MR. KOBELAK: Yes.

MEMBER WALLIS: Yes. So there isn't any subdivision into small, medium and large? Okay.

MR. KOBELAK: What the ASTRUM methodology is, it's built off of our prior 1996 best estimate LOCA methodology. And what we do is we have a set of reference transient conditions, which is essentially the nominal operating conditions for the plant. At that point we will run a set of confirmatory studies to determine what the limiting steam generator tube plugging level is, the limiting vessel average temperature. We run several Cobratec cases at both the high Tavg and the low Tavg window and we determine what the limiting case is. And we take these cases into our uncertainty analysis. And essentially what we do is we will randomly sample from all the different uncertainty parameters and we'll run 124 Cobratec cases from all these randomly sampled parameters. And then we determining the limiting PCT and oxidation values from the 129 Cobratec cases.

CHAIRMAN DENNING: Give us an idea of what variables are considered uncertain and for which you have density functions. And what are the variables that are considered conservatively, taken at a conservative value?

MR. KOBELAK: Okay. The parameters that are bounded would be the steam generator tube plugging level. The vessel average temperature we bound based on the nominal windows. So we will run several cases at the 576 and several cases at the 564. And then we also sample and uncertainty around what the limiting value is from the window.

The average power in the low power assemblies is a bounded parameter. And loss of offsite power versus offsite power available is a bounded parameter.

In the uncertainty sampling we will sample accumulator water volume, accumulator pressure, accumulator temperature, safety injection temperature, the peaking factors. And on top of that we will also sample the local parameters, blow down heat transfer multiplier, reflood heat transfer multiplier. So those would all be sampled within the 124 Cobratec cases.

MEMBER SIEBER: It seemed to me that Westinghouse at one time had a methodology that said for a given class of plants there was a broad accident analysis that fit plants in that category. and that if your parameters fit within certain defined limited, you didn't need to rerun the full blown LOCA analysis. Is my memory correct on that?

MR. KOBELAK: For this particular case we redid the entire LOCA analysis.

MEMBER SIEBER: Okay.

MR. KOBELAK: I honestly can't speak to what we've done.

MEMBER SIEBER: So that happened 10 or 15 years ago?

MR. KOBELAK: Yes.

MEMBER SIEBER: Apparently I can't either. But it seemed to me there was a lot of parameters that were variable parameters in here like, you know, it was the multitude of tens of parameters that are important in the analysis.

MR. KOBELAK: Yes. In the ASTRUM analysis we sample, I believe it's 38 different parameters --

MEMBER SIEBER: Right.

MR. KOBELAK: Using the Monte Carlo method.

MEMBER SIEBER: Okay.

CHAIRMAN DENNING: And what are the

fundamental differences between that and the SECY 83 472?

MR. KOBELAK: In the SECY analysis there was a lot of parameters that we would bound rather than sample uncertainties around them, we would use a limiting peaking factor. In ASTRUM we only determined four bounded parameters from these conformity studies. And everything else is run at a nominal value. And then we do the uncertainty sampling afterwards.

CHAIRMAN DENNING: So that there is the complete mixing together of what we would call epistemic and aleatory uncertainties here? Both types of uncertainties are treated in a probabilistic manner rather than looking at a particular worse state of the plant. And then from that worse state of the plant, from an aleatory version seeing what's the uncertainty in the best estimate?

MR. KOBELAK: Yes. We will only bound those four particular parameters and then the rest of them are all sampled.

CHAIRMAN DENNING: And the Staff has accepted this approach? Is that true? Has this been reviewed and this approach has been accepted?

MR. NAKOSKI: Yes. This is Jim Nakoski. I'm the PWR Systems Branch Chief.

And the answer is ASTRUM has been reviewed and approved by the Staff.

MEMBER WALLIS: Is the break size one of these random variables?

MR. KOBELAK: Yes. For double ended guillotine breaks we will sample a discharge coefficient. For split breaks we will sample a discharge coefficient and the break size.

MEMBER WALLIS: But you sample the size itself?

MR. KOBELAK: Yes, we sample the break size as well.

MEMBER WALLIS: So the break sizes are random input?

MR. KOBELAK: Yes. The break size and the discharge coefficient are randomly --

MEMBER WALLIS: And you have some kind of a probabilistic assessment of the probability of these various break sizes then?

MR. KOBELAK: We do not factor that into the LOCA analysis.

MEMBER WALLIS: So it's a flat, they're all equally likely?

MR. KOBELAK: Yes.

MEMBER WALLIS: That's --

CHAIRMAN DENNING: Well, you said you didn't factor that in, but your answer was you did but with a flat answer?

MR. KOBELAK: Well, yes. We sampled them all at an equal probability. We don't --

MEMBER WALLIS: An equal probability?

MR. KOBELAK: Yes.

MEMBER WALLIS: Which is really presumably conservative. Large break is less likely than a medium break?

MR. KOBELAK: Yes.

MEMBER WALLIS: And they're all given equal probability?

MR. KOBELAK: Yes. There's a 50/50 percent change of whether it will be a guillotine break or split break.

MEMBER WALLIS: No, but I know. But size, the size?

CHAIRMAN DENNING: And when you say the --

MR. KOBELAK: And the --

MEMBER WALLIS: When you've a size range of, I don't know, one square foot up to however many it is, the maximum--

MR. KOBELAK: Yes, and we -- that is --

MEMBER WALLIS: Do you sample flat in that range?

MR. KOBELAK: Flat, yes.

CHAIRMAN DENNING: Why did you consider that to be conservative, Graham? Don't forget, we're not looking at probabilities here. This isn't the PRA. This is saying that probably is the less challenging LOCA at one square foot has equal likelihood to the most challenging so that your --

MEMBER WALLIS: No. But then the consequences depend on the size of the break, as I understand it. And so if you happen to just randomly get large break LOCAs, you're going to get higher temperatures in your output. Whereas, in reality there's -- in reality? According to expert elicitation the large break LOCA is considerably less likely than the one square foot. The largest break is significantly less likely than a one square foot break. And I think what some other people have done is to actually put in a more realistic probability distribution for the size of the break.

And this I think is conservative. This comes out with more large break LOCAs as inputs than is realistic.

CHAIRMAN DENNING: I would disagree.

MEMBER WALLIS: Or more of the largest

break.

MR. FINLEY: Certainly from a regulatory standpoint all the breaks need to show a PClad temperature less than 2200 degrees Fahrenheit.

CHAIRMAN DENNING: All of those do you're saying?

MR. KOBELAK: All of it.

CHAIRMAN DENNING: So you take a large break and for that one you determine what the --

MEMBER WALLIS: No.

CHAIRMAN DENNING: That's what --

MEMBER WALLIS: Large breaks is a spectrum break, as I understand it.

CHAIRMAN DENNING: Right.

MEMBER WALLIS: It's not as if large break is the biggest break.

CHAIRMAN DENNING: No. I meant the biggest break. You take the biggest break and demonstrate for that one or are you treating that probabilistically so that --

MR. KOBELAK: We will take the results of all those 124 runs across the break spectrum and we will show that the most limiting of all of those is still less than 2200.

CHAIRMAN DENNING: You don't use the

statistical --

MEMBER WALLIS: Yes. That is the statistical. Let's get it straight. There are two ways to do this.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: You can say we're going to take breaks of say, 1, 2, 3, 4, 5 categories, right, of sizes?

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: And we're going to run statistics on one and get a number. Statistics on two and get a number. Statistics on three. And then we're going to look at the biggest number of PCT we get out of these six categories.

The other to do it is to put in all of these breaks into the statistics.

CHAIRMAN DENNING: Then that --

MEMBER WALLIS: Then you may randomly never get the biggest break possible at all. It may just happen that you'd never get that.

CHAIRMAN DENNING: Oh, you mean in the sampling?

MEMBER WALLIS: In the statistical process you may never hit the biggest break, doubled ended --

CHAIRMAN DENNING: In a statistical

sampling? Well, you'd probably sample in such a way that your forced --

MEMBER WALLIS: Well there's a good probability of it, but you're not sure you'll get that--

CHAIRMAN DENNING: Well, you'd probably do that in a structured way like sampling where you --

MEMBER WALLIS: Well, I think I know what you've done. You have used the break size as an input statistical parameter. Just like these other things with the correlations and --

MR. KOBELAK: Yes. Exactly. That's one of the sample parameters similar to it.

MEMBER WALLIS: And then I can talk with my colleague about what it means at some other time.

MEMBER SIEBER: It seems to me the issue is you've got a lot of parameters that you want to vary. And if you ran a case for all 34 parameters at its limits, we wouldn't be here; you'd still be running your computer code. I mean, that's thousands of cases. So this is a reasonable way to cut down the number of runs that you have to make to still define an envelop in which you can operate safely. That's sort of my way of looking at it.

MEMBER WALLIS: Well, they're using a

statistical something out there with a certain confidence that they've got if they covered the certain range of the probabilistic space. And if they run this code on Tuesday, they may get a different answer than they get on Monday using exactly the same method.

CHAIRMAN DENNING: Now is the criterion for being satisfied is that every one of these cases as to be below the --

MEMBER SIEBER: The 2200.

CHAIRMAN DENNING: -- 2200? It's not the 95th percentile or something like that?

MR. KOBELAK: Right. It's that all of these cases will be less than 2200. All of these cases will be less than 17 percent oxidation.

MEMBER WALLIS: Based on a 95/95?

MR. KOBELAK: Yes.

MEMBER WALLIS: All right. And if you wanted to take the second one, you'd have to take 295 or something --

MR. KOBELAK: Yes. The 124 is enough to assure that we will find at least the 95/95 PCT and oxidation. And for each additional parameter that you would be looking for, then the number increases.

MR. CARUSO: If you run your cases on

Monday and you get an answer where one of them exceeds 2200, what do you do? Do you just run it again on Tuesday and if it's okay, you accept Tuesday's results and throw away Monday's?

MR. KOBELAK: No. Whenever we run the code to determine the sampling and develop these 124 cases, once we've run that code we will maintain that seed. So if we were exceed 2200 from that analysis, we would have to find ways of reduced peaking factors, some way to meet that limit. We would not resample.

MEMBER WALLIS: It would be very interesting if the government ran confirmatory analysis and it doesn't matter whether it's Monday, Tuesday or Wednesday. It's just that since they sample differently, they get a different number. IF they get a number which is 2200 and one and you get a number which is 1999, it would be interesting to see what they would do.

MR. KOBELAK: Yes. Fortunately, we didn't challenge the limits with this analysis.

MEMBER WALLIS: But you seemed to come up with an 1800 and something number. It's not as if you're sort of near the limit, as I understand.

MR. KOBELAK: Yes. The 1870 was the limiting case we had.

MR. FINLEY: Okay. Thanks. Thanks, Jeff.

With respect to the small break methodology, no change in that methodology. Continue to use the NOTRUMP method from Westinghouse.

For the non-LOCA events we have gone to the updated methodology, the RETRAN methodology for the system code. Presently we use LOFTRAN for these non-LOCA events.

For the control system transients we continue to use LOFTRAN both now and for EPU.

For the containment analysis we currently use the GOTHIC methodology, although a slightly older versions of what was used by Westinghouse for the updated EPU containment analysis.

For steam line break we currently use COCO, that's being updated to the GOTHIC methodology.

And finally, for dose assessment we did et the alternate source term methodology approved last year and we just updated that for the EPU source term.

MEMBER SIEBER: And those, the dose to control operators, it seemed to me come out pretty low, right? It's in the two or three rem range?

MR. FINLEY: Well, we'll show you the results for the control room in a few slides.

MEMBER SIEBER: Okay.

MR. FINLEY: Okay. What I tried to do on this slide is capture the most significant of the non-LOCA events. I think this speaks to some extent to the questions or comments that came up early on with respect to margin.

I would like to say at the outset that obviously these methods are conservative. They're approved methods. As well the inputs to the methods are also conservative and bounding.

And finally, the acceptance criteria that you see here are conservative. So there's margin in these results, although it appears they're close to the acceptance criteria.

To summarize, I've grouped these in four categories. Overheating as a result of reduced primary cooling being the first.

MEMBER WALLIS: Could we look at these now? These seem to be important numbers?

MR. FINLEY: Yes.

MEMBER WALLIS: And it looks as if in every case your result is very close to the criteria?

MR. FINLEY: Yes. Yes. And as I said, there's conservatism in the methods and in the inputs and in the criteria. In addition, when we did these analyses, our objective was not to demonstrate how much margin we had to the acceptance criteria. Our objective was to demonstrate that we meet the acceptance criteria.

MEMBER WALLIS: Well, you seem to have very carefully engineered this plant so that it's close to the envelop in a lot of different dimensions here.

MR. FINLEY: Well, in some sense that's true. In other words if we made changes to inputs into these methods, we typically would stop at something that would give us an acceptable result, and that's why you see the results that you see here.

MEMBER WALLIS: And then we may have some concern when you say things are conservative about just what you mean and how much the uncertainty is some of these numbers. We really dug into this.

MR. FINLEY: Yes. I understand. Let me give you an example. In fact, I'll call upon Chris McHugh from Westinghouse here.

But take the first loss of flow condition 2 event, for example. We show the DNBR acceptance criteria here for DNBR at 1.38 and we calculated 1.385, but that looks very close to the limit. There is margin in that 1.38 acceptance criteria for the DNBR limit. And let me ask Chris McHugh to speak to that just as an example.

MEMBER WALLIS: Well this 1.385, does that come from the mean of some best estimate? There's no uncertainty put on that number for me.

MR. McHUGH: This is Chris McHugh from Westinghouse.

That's the actual calculated out of RETRAN or out of --

MEMBER WALLIS: But RETRAN isn't that accurate a code, is it? I mean, this could easily be plus or minus something or other. I don't know how big it would be. But if that's the number that RETRAN gives you, there's a plus or minus on that which is not insignificant, is it?

MR. FINLEY: Well, this of course gets back to the thermal hydraulic methodology as well, which is essentially a 95/95 type methodology --

MEMBER WALLIS: Is it? I mean is this 1.38 a 95/95, it isn't, is it? Isn't it just one point from RETRAN code?

MR. FINLEY: With respect to the thermal hydraulic analysis this does incorporate variations in power, temperature and flow.

MEMBER WALLIS: Please, now I want to be clear. Is this treated the same way as the LOCA, this is 1.35 number as with the 124 or whatever the number of runs is?

MR. FINLEY: No.

MEMBER WALLIS: No, it isn't?

MR. FINLEY: That's a single bounding run.

MEMBER WALLIS: It's one run? And we know that these codes aren't all that accurate. They have correlations and things in them which do not represent data perfectly. They have assumptions in them. And they have simplifications and --

MR. McHUGH: Well, the correlation uncertainties are accounted for in the DNBR limit. The actual limit that he has listed there of 1.38, the actual limit for the 14 by 14 422V+ fuel is 1.24.

MEMBER WALLIS: So you're saying that the Agency accounts for correlations in the way it specifies the criteria it accounts for uncertainty in correlations in the way it --

MR. McHUGH: Yes.

MEMBER WALLIS: So when it approves RETRAN it's implying that it knows that RETRAN has uncertainty within the limits that were considered in setting the criteria?

MR. McHUGH: Well, it approved RETRAN with the methodology that we planned to use RETRAN with. It wasn't just the RETRAN code by itself. But then that methodology was used for --

MEMBER WALLIS: But then when you change the plant, the errors may change. So you're sort of assuming that your assessment of uncertainties in RETRAN before the uprate haven't changed in any way with the uprate?

MR. MIRANDA: I didn't understand the difference between the criteria and that' identified here, 1.38 and what you said the actual criterion is? What did you mean? Whose criterion is this and what did you mean by the --

MR. McHUGH: The DNB correlation that we used has a limit of 117. From 1.17 to 1.24 they --

MR. MIRANDA: I'm sorry. You said it has a limit. What do you mean by it has a limit?

MR. McHUGH: The approved limitation of the correlation is 1.17. We can't go below that. Because, like you said, there are uncertainties associated with the correlation. It's not perfect.

And then we used the revised thermal design procedure, which means we statistically convolute the uncertainties into the DNBR limit, and that takes the limit from 1.17 up to 1.24?

MEMBER WALLIS: So that it's the Agency

that's convoluting the uncertainties?

MR. McHUGH: Pardon me?

MEMBER WALLIS: It's the Agency? You're speaking for the --

MR. McHUGH: No. The vendor takes the -- the Agency gave us 1.17.

MEMBER WALLIS: Oh, so I don't understand this. So what's the law, let's say the law laid down by the governmental agency is 1.17?

MR. McHUGH: Well, yes. For the DNB correlation that we used, that's --

MEMBER WALLIS: Well, maybe that's what we should be looking at.

CHAIRMAN DENNING: Just for the correlation.

MEMBER WALLIS: So you have taken the kind of uncertainties in changing the criteria from some regulatory value to some other value?

MR. McHUGH: To a higher more restrictive value.

MEMBER WALLIS: It seems a strange way of doing it. I would think you would take your predictions and show that you meet some regulatory criterion specified by the government. Wouldn't that be the 1.17

MR. MIRANDA: This is Sam Miranda from the NRC.

We don't have a specific value like 1.17. The law says there should be a condition two event, for example, that there should be no fuel clad damage. And the 1.17 is determined by DNB experiments and correlations to come with a value that with good confidence will assure that there's no clad damage.

And then what Chris is talking about is adding on to the uncertainties they could either be put in directly or convoluted in to assure that you have this 95/95 confidence level that no clad damage will occur.

So you start with a 1.17 and by the time the uncertainties are added in, the limit, the safety analysis limit that the analysis have to meet, is 9.38.

MEMBER WALLIS: Then you make one RETRAN run with 1.385?

MR. MIRANDA: Well, in this case it's RETRAN, it was VIPRE.

MEMBER WALLIS: So this is very different from what we just heard from Westinghouse. They make 124 runs and then they compare a fixed criteria. And you're sort of stretching the criterion first and then making one run. That seems a strange way to do it.

MR. MIRANDA: Yes, this is not a best estimate calculation. These are conservative calculations. And the conservatisms are added, for example, in the initial conditions that are used in calculating the transient with RETRAN. And then the results from RETRAN are factored into a more detailed core model in VIPRE which actually calculated the DNB ratio.

MEMBER WALLIS: It seems that in order to satisfy ourselves you're doing the right thing. We ought to maybe spend a lot of time on these sort of things rather than just reading an SER which says they meet the regulation. Because how they meet the regulations is absolutely critical.

MR. MIRANDA: Well, these things have been addressed in detail in the past --

MEMBER WALLIS: It doesn't concern me. I want to be satisfied now.

MR. MIRANDA: I will --

MEMBER WALLIS: If you would point me to the reference, if there's something that I can study and be convinced, that's fine. But the fact that someone's done it before doesn't necessarily I'm happy.

MR. MIRANDA: Well, the licensing basis--

MEMBER WALLIS: I want to know what you're doing and why and what's the rationale for deciding everything is okay.

MR. MIRANDA: Yes. These methods have not changed from the licensing basis. In the EPU they used the same sort of treatment of uncertainties.

MEMBER WALLIS: So when they did it before, before the EPU, did they use 1.38 or some other number?

MR. MIRANDA: It could be any number, actually. It depends on the plant, it depends on the correlation used. And for this case it was a WRB-1 correlation.

MEMBER WALLIS: So what did they use before the EPU for these numbers? What did they use for this 1.38 before the EPU?

MR. McHUGH: I believe it was 1.38.

MEMBER WALLIS: It's the same thing?

MR. McHUGH: I'm not positive. I'd have to go back and check.

MEMBER WALLIS: And then the result, 1.385, did that change with the EPU?

MR. McHUGH: Yes.

MEMBER WALLIS: And what was it before?

MR. McHUGH: It was about 1.6 before.

MEMBER WALLIS: 1.6? So this looks as if they've moved very close to some limit as a result of the EPU? Should I conclude that?

MR. McHUGH: Yes.

MR. MIRANDA: Yes.

MEMBER WALLIS: If they got 1.375, you would have rejected the application?I

MR. MIRANDA: Personally if they had got 1.375, I would have questioned it.

MEMBER WALLIS: Well, I could ask that of all these numbers. When get to ATWS there's 3200, which is presumably -- is that an ASME limit or something for the 3200 or is that something that's varied in the same way that the 1.38 was varied?

MR. MIRANDA: Actually, the 3200 psi limit is the ASME level C stress limit --

MEMBER WALLIS: Which is something which is not subject to be twiddled?

MR. MIRANDA: Right. Well, it can be twiddled in the sense that it's the weakest component in the RCS.

MEMBER WALLIS: And then when I look at 3.93, does that have uncertainties in it, 3193? Is that a very conservative number or is that a mean, or

95/95, or what is it?

MR. MIRANDA: That number actually is less conservative than the other accident analysis, and that has been the ground rules for ATWS analyses since 1974 since ATWS is considered a very low probability event.

MEMBER WALLIS: It doesn't matter. You've got a criteria and it has got to be satisfied.

MR. MIRANDA: Yes. Yes.

MEMBER WALLIS: Probably or not.

MR. MIRANDA: And it is satisfied, 3193.

MEMBER WALLIS: And I know that large break LOCAs are very unlikely, but you still had to satisfy criteria.

MR. MIRANDA: That's right.

MEMBER WALLIS: So I don't accept the argument that it's unlikely and therefore you don't have to worry about it.

MR. MIRANDA: No. That's not my personal judgment. This is what the Staff has decided during the ATWS evaluations which have been going on since 1969 and then ended in the 1986 rule.

MEMBER WALLIS: That's a part of exasperation reading the SER was that I just read this whole thing and it says the applicant assumed this,

this and this and the ends of the paragraph saying -- or the several pages saying that he met the regulations. But unless I get into the details of how you let him calculate these numbers and how you evaluated whether or not they're satisfactory, I have no way of telling whether I give credibility to what you have done. And therefore, I need that presentation. I'm not sure I'm going to get it. So I may just have to defer and say I don't know whether or not this is a reasonable uprate, even though I may be impressed with what the licensee has done. Because I cannot follow the train of thought whereby the staff approves the numbers that are submitted to it.

MR. MIRANDA: I will be talking about that in my presentation later.

MEMBER WALLIS: Then we're going to have this conversation again.

MR. MIRANDA: Yes.

MEMBER WALLIS: Thank you.

I'm sorry to take so much time from the applicant.

MR. FINLEY: Well, that's fine. Important questions.

The next significant event is the locked rotor event, condition IV event. The pressure criteria is based on a 120 percent of design in this case, and you can see the margin that we have there.

For overheating, the loss of load event at most limiting condition II with respect to overpressure. And again this just takes into the sizing of the pressurizer which was asked earlier on this morning. The result is close to the acceptance criteria, which is 110 percent of design pressure. This was the event that was used to establish the limiting pressurizer safety valve setting that we talked about with respect to the license amendments previously.

For the feed line break analysis, that of course is a condition IV event. And here the acceptance criteria relates to not having saturation condition in the hot leg and we demonstrated that what remains subcooled with 2 degrees margin.

ATWS we just mentioned briefly the acceptance criteria of 3200 psig, 3193 the result.

For overcooling for steam line break it's a condition IV event. This event actually had not previously been analyzed for Ginna. We've added that to our licensing basis with EPU. And we continue demonstrate conservatively that we don't have clad damage for this event.

MEMBER WALLIS: Well, again, this linear heated or something --

MR. FINLEY: Heat rate, yes.

MEMBER WALLIS: Where does 22.7 come from?

MR. FINLEY: Let me ask.

MEMBER WALLIS: Is this in a reg. guide or something or where does it come from?

MR. FINLEY: Yes. That's one of the SAFDLs for the Westinghouse fuel, Specified Acceptable Fuel Design Limits for the fuel. Let me ask Westinghouse.

MEMBER WALLIS: So this is something that's written into the law in some way, 22.7? It's been approved and all that? This is actually a regulatory position of the Agency, 22.7? Yes?

MR. FINLEY: Let me ask Westinghouse. Chris or Roberta.

Okay. We're going to have to take that question and get back to you with respect to the basis for the 22.7.

MEMBER WALLIS: Also the basis for 22.67. They're so close and I'm just interested in where they come from.

CHAIRMAN DENNING: The other element that's so strange about this is how many -- and some of these things are clearly very closely coupled and it's not too surprising that some of these DNBR happen to be so close. But things like the pressurizer -- I'm sorry, the maximum pressure which is somewhat independent from the DNBR, here's within .4 of a criterion and then this somewhat independent thing, the DNBR is also so incredibly close to the criterion. And one would expect -- how have you tuned this somehow so that they're all right --

MR. FINLEY: I understand the point. And that's not by coincidence. It's really an outcome of the process. In other words, we would revise the inputs into these methods until we got the acceptable results. And again --

CHAIRMAN DENNING: And so you keep your setpoints --

MR. FINLEY: -- we're relying on conservative --

CHAIRMAN DENNING: -- you mean things like that?

MR. FINLEY: Pressurizer safety valve setpoints, for example, is key to limiting the overpressure for the loss of load.

MEMBER WALLIS: So you're changing the physical variables? You're not changing some correlation or some assumption --

MR. FINLEY: Well, in that case that's a physical variable. In other cases it may be analytical type margin.

MEMBER WALLIS: So the old joke about this used to be that you simply have a loop in the program that says if you don't get the answer you want, go back and assume something else. Now that's not the way you get the numbers so close, it can't be.

MR. FINLEY: No. No.

MEMBER WALLIS: But there must be some way that you worked to get the numbers so close.

MR. FINLEY: And that's correct. Certainly as part of the process we run these events the first time, we collaborate with Westinghouse with respect to the sensitivity of the event based on the inputs. And we decide to make changes in the inputs and changes to our operating margin at the site. And that's what we've done in this cases. So although some of these results are independent, they come from different events and driven by different parameters. The reason two or three are close is because we went through that process to revise our operating strategy, our setpoints and so forth to make these results acceptable.

CHAIRMAN DENNING: If we went back and

looked at Kewaunee, we would see basically the same type of thing? Would they all be up against their limits?

MR. FINLEY: I can't speak to all of the Kewaunee results here. I can't speak to that. I don't know the details.

MEMBER WALLIS: I've never seen this before. I mean, usually in these uprates we still have a large margin in that the numbers are not close up to some limit.

CHAIRMAN DENNING: Well, we have to be careful. I mean, these are not safety limits and they have margins built into them.

MEMBER WALLIS: Right.

CHAIRMAN DENNING: But we're not taking up all of that.

MEMBER WALLIS: We're taking it all off.

CHAIRMAN DENNING: We're going right up to the --

MEMBER WALLIS: Right, which I haven't seen anything like this before. It's really striking.

MEMBER SIEBER: These aren't the only limits. There are other limits where they don't approach them so closely.

MEMBER WALLIS: Are you just showing the

worse --

MR. FINLEY: Right. I'm obviously picking the most limiting events. And these are the ones that, you know, with respect to margins to the acceptance criteria are the tightest.

MEMBER WALLIS: So you're not going to give--

MR. FINLEY: But again -- for example, for the loss of load analysis we don't take credit for a spray system that would be there and it would be operating, it's not safety related. We don't take credit for the PORVs, the relief valves that would accurate before the safety valves.

I mean our typical loss of load event at Ginna results in much, much lower pressures than what you see here. So these are conservative methods, again, conservative --

MEMBER WALLIS: But if you read the SER there's many, many more events than this?

CHAIRMAN DENNING: Right.

MEMBER SIEBER: Yes.

MEMBER WALLIS: And they always end up saying the regulations are met.

MEMBER SIEBER: Right.

MEMBER WALLIS: What I want to see is a

table like this for all events which may be, you know, 35 or something. And then showing that these are the events which we have to think about because they're so close to some limit and arguing in some detail about why one part in ten thousandths is an acceptable margin for these things.

MR. FINLEY: Right.

MEMBER WALLIS: That's what I was looking for. I never found anything like that in the SER.

MR. FINLEY: In the licensing report we have a table that we could show you. We can make that available to you later today, I'm sure, that lists all the events.

MEMBER WALLIS: Well, I'm very surprised because in general I think that you guys seem to have done a good job. And I just don't understand why I've suddenly discovered that these numbers are so close in this table.

MR. VERDIN: This is Gord --

MEMBER WALLIS: I had not seen them before.

MR. VERDIN: This is Gord Verdin. I do have some comments on this.

First of all, the 22.7 kilowatts per foot is a 14 by 14 422V+ kilowatts per center line melting.

MEMBER SIEBER: Right.

MR. VERDIN: So it is a limit for that particular fuel design.

The other thing is one of the reasons some of these limits look as close, as I mentioned in my previous discussion, that we've made a transition from CAOC to RAOC. And when you make that transition to RAOC, you try to get the bands that you were allowed to operate within wide enough to give you operating margin. So some of your initiating conditions for these events are closer than they would have been in the past when we had CAOC analysis.

MEMBER MAYNARD: Well, as I recall, most of these criteria have most of the margin built into them.

MEMBER SIEBER: Right.

MEMBER MAYNARD: So as long as you meet that criteria, you have the margin and that you typically will come close to these in a number of areas to provide yourself operating margin. You don't actually set setpoints and things to the exact --

MEMBER SIEBER: Limit.

MEMBER MAYNARD: -- limit that you could.

MR. FINLEY: That's correct. That's correct. These acceptance criteria set the limit beyond which we begin to infringe on the safety margin. Below these limits we consider that operating margin. And that's how we approached the analyses.

MR. DUNNE: This is Jim Dunne.

I think another thing that we need to remember is typically for a lot of the parameters instead of inputs into these analyses, they're skewed in a conservative reaction. For example pressurized water level; if for a particular analysis it's conservative to maximize pressurizer water level, you take your nominal and you throw your uncertainty and raise it to a higher value as a starting point. Or if it was conservative to minimize it, you would take your nominal and reduce it by your uncertainty to a starting point.

So you've got a lot of the inputs into these analyses that have been skewed in a conservative direction to give you conservative result as a final output.

MEMBER WALLIS: Well, this reactivity to this rod withdrawn thing. That must depend on the time and the cycle at which it happens?

MR. FINLEY: That's correct.

MEMBER WALLIS: Is this the worst case you're showing us here?

MR. FINLEY: We look at different times in cycle, we look at different rod positions. And you have to have rods inserted.

MEMBER WALLIS: Well, that depends on your whole fuel arrangement and everything.

MR. FINLEY: That's correct. That's correct. We look at all those. This is the most limiting result of all the times --

MEMBER WALLIS: So you've run a lot of calculations with a lot of different inputs?

MR. FINLEY: That's correct.

MEMBER SIEBER: That's part of the reload safety evaluation.

MR. DUNNE: Right.

MR. FINLEY: That's correct.

MEMBER SIEBER: You do it every cycle.

MR. DUNNE: And when you your fuel reload for any particular cycle, you got to look at your reload design and see if it impinges upon any of these --

MEMBER WALLIS: Right. So there might be some reloads that gave you 27.486 --

MR. DUNNE: And if we did that we--

MEMBER WALLIS: --2748.6.

MEMBER SIEBER: Then you need to change

something.

MEMBER WALLIS: Then you go and change the reload.

MR. DUNNE: Well if we do a reload report and we get a number that's outside the band that presently analyzed, we basically have to review it whether we can accept that change under 50.59 or whether it's not accepted in the 50.59, then we got to go back and get the Commission's approval before we do that. Ideally what we would do would be to change the core design to stay within the design limits that we've been licensed to and not try and raise the limits higher.

MEMBER SIEBER: And I think that's typically what happens. In a situation like Ginna it is not surprising to me that you would find some of these things close to or up against a limit because the designer's question is how much can I increase the power without exceeding a limit. And they worked very hard to do that, and they may come right up next to a limit and say that's how many megawatts I can get out of the machine without exceeding a limit. And if he would do less then that, then he wouldn't be fulfilling the design requirement which is how much can I get out of the machine and still not exceed the limit.

So I'm not surprised that they're close on some of these.

MR. FINLEY: That's correct. And that actually responds to the question I think Dr. Wallis had earlier, or one of the gentleman had earlier, which events set the power limits. These are the events here that set the power limits we've chosen.

MEMBER WALLIS: Well, I guess we could spend a lot of time on everything. I don't want to do it. But just look at the rod injection, less than 200 curies per gram, and we have looked at -- it's a knowledge base for fuel damage. And there's quite a bit of uncertainty in that that's 200 curies per gram. And over the years there have been efforts to change the number in response to what we know.

So that's certainly one where I wouldn't expect you to try to get within .01 percent or something.

MR. FINLEY: I understand that.

MEMBER WALLIS: I mean, we could spend forever on all these numbers. I don't want to do it. It's just that this is a rather striking presentation, this particular slide here.

MR. FINLEY: And let me also say --

MEMBER WALLIS: Maybe we should move on.

MR. FINLEY: Okay.

MEMBER SIEBER: I just would, not trying to belabor the point, point out that depending on where the issue came up in the licensing process determines to some extent how it's treated.

For example, the ATWS event as the staff has reported has been out there and the subject of policy and rulemaking for a long time. And because it is not a likely event, for example, ATWS mitigation equipment is not safety related. It's not safety related equipment reflecting the fact that you aren't going to get an ATWS with a combination of other kinds of accidents like outages and so forth.

So there are a lot of twists and turns in the rules that determine what these limits really are and what they mean. There's a long history behind a lot of this.

MEMBER WALLIS: I'd like to request that when you make a presentation to the full Committee you don't fail to show this sort of slide. Because sometimes what happens is that the points that are sensitive in the Subcommittee meeting get passed over when it comes to the full Committee. And I think you want to be completely open about this.

MR. FINLEY: All right. We'll include this slide in that presentation.

CHAIRMAN DENNING: You can proceed now.

MR. FINLEY: Again, sticking with results from the safety analysis with respect to the LOCA analyses, large break Pclad temperature 1970 as compared -- I didn't show the acceptance criteria here. You know 2200.

Small break is actually not -- the review from the Staff is not complete. But the current result submitted is 1167. Obviously, a margin there.

MEMBER SIEBER: If you were to use your old methodology, what would that number have been?

MR. FINLEY: Let ask Jeff Kobelak from Westinghouse.

MEMBER SIEBER: 2195 maybe?

MR. FINLEY: Let me ask Jeff Kobelak to answer that question.

MR. KOBELAK: With the SECY methodology at the prior to EPU conditions, the 95/95 PCT was 2087 degrees.

MEMBER SIEBER: Which was okay.

MEMBER WALLIS: So you can certainly buy something by changing the methodology?

MR. FINLEY: That's correct.

With respect to the containment, you see the results here for the LOCA and the steam line break, 54.2 psig as compared to the design pressure for 60 for LOCA --

MEMBER WALLIS: I'm sorry. When he said "the number is" he was talking about the large break?

MR. KOBELAK: Yes.

MEMBER WALLIS: Yes. Thank you. Just clarifying.

MR. FINLEY: And that result 54 pounds is comparable to what we had for LOCA now, slightly higher.

For steam line break 59.6 psig, it's actually a little lower than our current licensing basis for a steam line break. That's a tight analysis for Ginna even now. When we installed the fast acting feed insolation valve, it actually took that single failure away as the limiting case for steam line break containment. But there are other single failures that also result in this 59.6.

MEMBER WALLIS: You know, when I read the SER I read a statement that said the licensee stated that no fuel damage is postulated to occur because of a main steam line break. Well, it maybe true that there's no fuel damage. But you can't assume the answer. You can't just postulate something. You've got to have some justification for it.

MR. FINLEY: Well, that's correct. And we I think mentioned earlier that when we did the steam line break under non-LOCA we demonstrated no clad damage.

MEMBER WALLIS: Well, you demonstrated. But the SER it simply says you postulated. That's not a proper description of what you did.

MR. DUNNE: That's correct. It's not an assumption. It's based upon analyses.

MEMBER WALLIS: Right. And in the rod injection accident you assumed that a certain amount of rods fail? Did that just come from the sky or did you know how many failed and for some reason?

MR. FINLEY: Are you moving ahead to dose assessment slide?

MEMBER WALLIS: Well, I'm just looking at how -- trying to figure out what you did in terms of calculating things and how the Staff evaluated them. And when I see that they simply say you assumed the answer, I don't understand how that's an acceptable position to have.

CHAIRMAN DENNING: In some respects it's a question for you. It's really SER verbiage, but really the question in both of these cases was did you really make assumptions or did you actually perform analysis --

MR. FINLEY: We actually performed analysis to demonstrate the fuel behavior during these transients, yes.

CHAIRMAN DENNING: Okay. I think you can continue.

MR. FINLEY: I do want to mention that although the design pressure of the containment is 60 psig, when we replaced the steam generators in 1996 we did a structural integrity test of the containment at 82 psig, just as an example to show the conservative nature of the design pressure.

With respect to dose assessments, I mentioned earlier that we already had approved last year the --

MEMBER MAYNARD: I'm sorry. That was done after the replacement of the steam generators?

MR. FINLEY: That's correct.

MR. DUNNE: Yes.

MEMBER MAYNARD: Because you had to put a hole in the containment to put those in. So you did the integrity test after that.

MR. DUNNE: This is Jim Dunne.

Yes, we did a normal integrated leak rate test, we went up to 115 percent design and checked containment leakage, which was nominally 69 psig. And then after we completed that test, we took it up to 72 psig, held for a while to monitor conditions to basically check containment integrity at that higher pressure.

MR. FINLEY: The alternate source term methodology was approved last year for Ginna, and that's what we utilized. For EPU upgrading, of course, the new source term.

Also of importance is that Ginna recently modified the plant to incorporate two new safety related ventilation trains for the control room. We also did the in leakage test with tracer gas and came up with a recent far below what was assumed in the control room dose assessment, 300 scfm. The source terms are consistent with Reg. Guide 1.193. We did update the X/Qs. And the calculated doses, as you'll see here in a second, are within the guidelines of 10 CRF 50.67.

MEMBER SIEBER: Do you have any idea of what the result would have been not using alternate source term, but using TID 14844?

MR. FINLEY: Let me ask Ken Rubin here.

No, we don't have that information. We didn't do those analyses. It would be difficult to estimate it.

MEMBER SIEBER: Well, I don't want you to guess at them.

MR. FINLEY: Right.

In terms of the results, as you can see we essentially redid the dose assessment analysis for all of the events. Here they are before you. I won't go down each one.

Of particular note are the locked rotor and the large break LOCA results for the control room in particular. Those were the only two results which actually increased more than ten percent of the margin to the acceptance criteria. That's important, as you know, with respect to 50.59. Those results need to be reviewed and approved by the Staff. And they're in the process of doing that.

All the other results, small changes with respect to the margin to the acceptance limits.

MEMBER MAYNARD: And even those were within the criteria, but there was more than a 10 percent change, so --

MR. FINLEY: That's correct. Still within the criteria.

And in conclusion with respect to the

safety analysis, all of the safety analysis met the acceptance criteria. This demonstrates that the NSSS and Emergency Safety Features at Ginna are robust. And, again, this is not a surprise. This was the expectation given our similarity to the Kewaunee design and their safe operation to date.

I think at this point we'd like to ask the staff to make their presentation.

MR. MILANO: Before we get started, I'd like to clarify one point. You asked about the approval of ASTRUM. And while it's been approved generically, that is one of the amendments that's still under -- that is the amendment that's still under Staff review that constrains the power uprate. We have not yet issued an amendment approving the use of that best model on Ginna. Okay.

Also for the Staff's review, as with Ginna, we're going to have two different organizations providing the Staff's response. We'll have the PWR Systems Branch going over the various accidents and transients. And then followed up by the Accident Dose Branch, which will provide our accident dose consequences.

Sam Miranda, although there were a number of individuals that reviewed the reactor systems area, Sam Miranda has the lead for the overall management of the reactor systems review.

And also speaking today along with Sam will be Kent Wood and Lyn Ward.

MR. MIRANDA: Yes. And we also have here John Nakoski, the branch chief for Pressurized Water Reactor Systems Branch.

At this point I just want to introduce the topics we're going to cover and go right to Kent Wood who will discuss the fuel assemblies nuclear design and thermal hydraulic design. Then I'll come back and we'll talk about the accident analyses. And I'll give it to Kent Wood right now.

MR. WOOD: Good morning, gentlemen. My name is Kent Wood. I'm a reactor systems engineer in the Pressurized Water Rector Branch.

MEMBER WALLIS: Excuse me. I'm just trying to look at the schedule here. We have all kinds of material being presented, but isn't safety analysis the key thing in all of this? I'm just wondering why we have a short time on safety analysis and a lot of time on things which may not be so important to safety.

MR. WOOD: That's not my purview.

MEMBER WALLIS: I'm just wondering it

would be appropriate to dig into the safety part much more than some of these other parts and maybe take a bit more time with it. I'm not sure, but that's the comment I have.

MR. MILANO: You know, if you want to spend some more time, the Staff can accommodate your schedule and stuff. This was our best understanding at the time as to how much time based on the length of our presentations and giving you what we thought at the time sufficient time to ask questions.

CHAIRMAN DENNING: We'll give some thought to this perhaps over lunch as to whether -- and it may be very difficult for you to readjust anyway. But my guess is that when we get to some of these areas, we'll move through them very quickly. We'll see.

MR. MILANO: Right.

MR. WOOD: In executing their extended power uprate, Ginna is switching from what is currently Westinghouse's design of the optimized fuel assembly to a 14X14 422 Victor Plus or V+ design, which is actually a derivative of the fuel design that was approved as the Vantage Plus design under WCAP. It was approved the NRC and then subsequently modified slightly by Westinghouse. This is the same fuel assemblies that are essentially the same assemblies like were discussed earlier by Mr. Verdin. That these are currently installed and in use at Point Beach and Kewaunee. Kewaunee is actually these assemblies at the current power level essentially that Ginna is requested.

The notable difference is that over the OFA fuel that Ginna currently have is that you're going to put the more fuel in. It's approximately about 20 percent more fuel that allows them to keep their fuel densities and their power densities down.

The fuel rods are longer, that were discussed. That accommodates your increased internal pressure from the burnups.

And also what was addressed by the licensee was the RCA position of the deltas and that due to the top nozzle change.

What I focused on in my review was I wanted to look at the transition effects considering the differences between the OFA fuel and the 422V+ fuel. And I focused on like the flow differentials that they were going to have that would incur vibrational differences and flow starting for the OFA fuel. And I also looked at the assembly compatibilities. And I also went through the SRP, standard review plan, acceptance criteria which was for fuel damage. I looked at stress and strain, fatigue, corrosion, crud, internal rod pressure and growth. And for the rod rod failure on focused on like threading an hydrogen pickup, overheating of the fuel in the clad and for fuel culpability it was the structural integrity.

A lot of that I looked at. We conducted an audit at the Westinghouse facilities in Monroeville the first week in November. During that I looked at the calculations and reports for their flow testing mechanical capability. I looked at their calculations and reports for their control rod drop times. And their calculations for their fuel rod performance. These were all done in accordance with previously approved NRC codes and methodologies.

With respect to nuclear design, they're changing some design parameters and was discussed before. Design parameters are subject to the actual plant specific or core specific parameters are subject to change from one cycle to the next. What they have done is they're changing boundary parameters that they use in their safety analysis.

And as was mentioned before, I forgot who asked the questions, there's a standing of Westinghouse reload design methodology which a WCAP, I think it's 9272 which would tell them that they go through a list of key parameters. And if these key parameters are met for a given plant, each plant would have it's own key parameters. Then you verify that the design is bounded and therefore you wouldn't have to redo each analysis every time you reload the core.

As I mentioned down here, it's the 9272 WCAP that provides the continuity.

The actual acceptability for a given nuclear design parameter is actually demonstrated by the acceptance of the transient analysis. And to do that I went through and reviewed the transient analysis and the results that were reached because the transients were reviewed by a different staff member. And their results and conclusions to show that the transient analysis were acceptable at these design parameters as the bounding limits.

With respect --

MEMBER WALLIS: How did you determine that they're acceptable?

MR. WOOD: Excuse me, sir.

MEMBER WALLIS: How do you determine that they are acceptable?

MR. WOOD: Okay. Well, the design parameters, nuclear design factors are factors in how the core responds during a transient, the maximum limits that they --

MEMBER WALLIS: But you determine that the methods used were approved or you look at the results and you apply some criteria or something?

MR. WOOD: Well, these are parameters that factor into the transient analysis. And if the transient analysis using these design limits show acceptable results, then these nuclear design parameters would be acceptable.

MEMBER WALLIS: So the bottom line is you compare some number with some other number, is that what you do?

MR. WOOD: As a review at the NRC, I don't have a different number to compare to. What the analysis that's performed is that the transient analysis will take a given set of input parameters of which these would factor in the different transients.

MEMBER WALLIS: Right.

MR. WOOD: And then if that transient shows acceptable results with those input parameters, then they're considered acceptable. If it doesn't, then you decide as a designer for designing that core or those parameters what you need to modify in your design or your plant to make them acceptable.

MEMBER WALLIS: Because I mean I could see that if you read this thing, you could say well you go through and these look like reasonable design parameters. But I'm not quite sure about how they chose their hot channel factor. And then you go through and then you compare with some criteria. And if the criterion satisfied with a lot of margin, you may not go back and review what you questions before. But if you're very close to some limit, you would say well I wasn't too convinced about they did with hot channel factor. I'd better go back and dig into that and find out if that is sort of swinging the results too close to the limit.

And I just wanted to be sure you guys are digging into things which might give you a little bit of concern if they influence the answer too much and they're not too well presented, and things like that.

It's just not a routine checklist and you just go through it without much thought?

MR. WOOD: No, sir. But that iterative process of checking with the individual parameters would be done when that transient analysis was reviewed.

MEMBER WALLIS: What helps you achieve credibility sometimes is by saying everything looked fine except I was a bit concerned about this and this is what I did. And if you can explain how you did it, that sometimes help achieve credibility. Just reading through blind statements everything works fine doesn't tell us anything about how you went about it.

So I don't want to interrupt your --

MR. WOOD: No, that's okay.

MEMBER WALLIS: -- train of thought here, but that would help..

CHAIRMAN DENNING: Let's interrupt you just a little bit on more on that. In the parameters that you've identified up there, those are all inputs to the transient analysis, yes? Those are all inputs?

MR. WOOD: They're not all of the inputs, but they are inputs --

CHAIRMAN DENNING: Yes, but they're all inputs?

MR. WOOD: -- of the safety analysis. You know your shutdown margin, as was described earlier, they have now fully put in the feedwater regulation modification. They needed a shutdown margin of I think it was 2400 PCM. And with that they show that they only need a shutdown margin of 1300 PCM. So that's an example of where you make a plant change to, you know, like shutdown margin they're losing shutdown margin because of the uprate because of the additional fuel and reactivity that's going to be in the core. So in order to gain some of that margin and make sure that their examples are going to be acceptable with that uprate and that decreased shutdown margin due to the uprate, they go in and they make a modification of the power plant that, you know, like this is demonstrating iterative effect. I'm going to lose some shutdown margin, I need to gain some, what can I do to do that. And one of the things they did to do that was to make the feedwater reg mode change. And now the shutdown margin that they need to have to show acceptable results, you know limiting transients would be a steam line break at the end of cycle is now 13000 PCM as opposed to 2400 PCM because of a modification they made to the plant.

And so those are the types of things that we question. Several of those things get questioned back and forth over like questions that the Staff asked to the licensee to explain further and more detail.

I mentioned that we conducted an audit with Westinghouse where we actually reviewed some of their calculations. And one of the things that I was concerned about was the incompatibility differences between the old OFA fuel and the new 422V+ fuel. Like I reviewed those calculations for the flow differentials, the testing reports that they did for establishing the fuel assembly loss coefficients, and those type of things. Looked over their rod drop calculations for their rod insertion times. I questioned them about the raw positions on how they were going to adjust RPM, on how they were going to deal with that with the different heights and things like that.

And so it's not just that -- what you see in the SER, Safety Evaluation Report, isn't everything that we've ever discussed with them. It's a, you know, perhaps too much of a *Reader's Digest* version of what we've asked and discussed with the licensee over the course of the review.

CHAIRMAN DENNING: I was trying to get a feeling for within the context of where you are right now, when you talked about acceptability shown by transient analyses are you talking about operational transients are you talking about actual analysis?

MR. WOOD: I'm talking about the safety analysis transients that they --

CHAIRMAN DENNING: Safety Analysis transients. So the DNBR that in comparison with some criterion would be what you would determine to be the acceptability.

MR. WOOD: Right.

CHAIRMAN DENNING: So things like that?

MR. WOOD: Yes, sir.

CHAIRMAN DENNING: Okay. I understand.

Okay. And the DNBR, I anticipate another lively discussion.

In the change from the OFA to the 422V+ fuel there is several differences. One is that due to primarily a change in the grid decision and some other aspects, and the top nozzle I believe, this would be the actual total assembly coefficient for the flow -- flow loss coefficient for the new fuel is less. And that's what drives what we were talking about earlier as the pressure differential across the fuel. So that can get their cross flow and the mixing and things like that.

I probably should have put more of that translates into your transition core DNBR penalty. Now they developed their DNB penalty in accordance with the previously established and approved NRC method that was done. So they did that in accordance with -- because it's not the first time that somebody's transitioned core designs that they've had to account for these type of flow imbalances between the assemblies and the core. So there's a methodology that's been established to deal with that.

They changed from the THINC IV code to the VIPRE I code. The VIPRE 1 is the more flexibility, it always them to a little more things in the transient analysis. It handles the transient analysis during the nonsteady state activities better than the THINC does.

So the similarities is the use of the revised thermal design procedure with the DNB correlations that WRB1 and in the standard thermal design procedure with the W3 correlation.

And then the limits are pretty much the same from before and after. Those limits were -- I'll discuss them because I know that they're of interest to the Committee.

The limits for -- and then there's a DNBR limit is applied -- a penalty is applied to the OFA fuel so that the limit for the OFA fuel is less than that for the 422V+ due to the flow disparities between the two.

The flow correlations, these correlations have a limit. And for the correlation for both of them for the WRB1, the correlation limit is 1.17 DNBR. And what that means is that that -- to the limit that' set when that code and correlation and methodology for applying that code is applied to and approved by the NRC, that takes into account the exact codes and correlations and methodologies of how it's applied. Able to accurately within the 95/95 percent confidence predict or regurgitate the data that it's based on. And then that's the correlation limit.

And for both the OFA fuel and the 422V+ fuel that's 1.17.

And then for a site specific limit you get into a design limit which they take and they put the site specific uncertainties into that. And for Ginna for the OFA and for the 422V+ fuel after they put in that, that's another design limit which is 1.24 percent DNBR.

And then to ensure that you have additional margin to the analysis criteria, the setpoint, the number that they're trying to prove that they meet in the safety analysis limit as a DNBR limit is 1.38.

So if you meet exactly 1.38, you're already .14 percent over your design limit. So if you meet exactly your safety analysis limit, you already have margin over your design limit which includes uncertainties. So that's how those uncertainties are factored into trying to determine the acceptance for your DNBR consideration.

CHAIRMAN DENNING: A question about the additional cross flow between the two fuels in a transition. Can you use VIPRE directly to determine what the effect is on the DNBR or do you -- how do you do that?

MR. WOOD: You can't calculate the directly. What is done is you do a two core analysis, one with assuming all of the one fuel design or the other. And then you go through the transition penalty process and determine -- okay, well I'm going to have the first core, they're going to -- I believe the number they're predicting is 53 assemblies of the 422V+. So your transition core penalty methodology comes up with a relationship that is relative, is based on the number of the different types of fuel assemblies that you have in the core, it's a fraction of those. And then based on that number you get a penalty and then you apply that to the limited assembly, like in this case it would be the OFA fuel assemblies. So they'd get a penalty based on what they're allowed to see as DNB for that assembly.

CHAIRMAN DENNING: I didn't understand.

MR. WOOD: I'm sorry.

CHAIRMAN DENNING: It sounds to me like that there was -- that there were be flow diverted from the one assembly to another assembly when they're side-by-side that wouldn't be seen in uniform cores.

MR. WOOD: That's correct. That's what causes the imbalance and the need for a transition core penalty. Because those assemblies that have that higher pressure resistance, they're going to see less flow because it's going to go to the other less resistent assemblies. And so you have to apply a DNB penalty to those assemblies to make sure that they still meet your acceptance criteria.

CHAIRMAN DENNING: Yes. But it sounded to me -- I didn't under the way -- it sounded to me like you're talking about a formula for calculating that penalty that didn't seem phenomenological.

MR. WOOD: There's a methodology that there is, that you do calculate a formula that's based on the number of assemblies of the percentage of OFA assemblies that you have in the core. And say okay now I have to reduce that allowed DNBR for those type of assemblies by a certain amount. And that's a penalty that goes that on their DNBR limit.

CHAIRMAN DENNING: I wonder, can the applicant jump in and help here as far as how you actually determined that penalty?

MR. FINLEY: Mark Finley again. I'm not a thermal hydraulic expert. Let me ask Westinghouse whether they have someone here to answer that question: How the flow diverges from the new fuel to the OFA fuel is taken into account in the thermal hydraulic analysis.

MR. DOMINICUS: My name is Dave Dominicus from Westinghouse.

And no, we do not have a T&H expert with us. We're going to call back to Pittsburgh.

MR. FINLEY: We'll get that answer for you this afternoon, okay?

CHAIRMAN DENNING: Fine.

MR. DOMINICUS: Okay.

MR. WOOD: And with, I'd like to introduce Sam Miranda to discuss transient analysis.

MR. MIRANDA: First of all, the SER that you have is written according to the guidelines of the review standard for extended power uprates. And a lot of the language you see is template. The original language is basically in the technical evaluation part and the conclusions.

There were some differences I might point that that relate to the Ginna plant design. For example, it is an older plant and there is a discussion in there about applicable GDCs. And in large part they satisfied the applicable GDCs. One GDC, for example, that did not apply is GDC 5 which relates to dual plants on the same site. And obviously, this plant is not covered by that.

There was a change in methodology that Ginna shifted from LOFTRAN to RETRAN and from TINC to VIPRE. And all of those codes have been approved by the NRC.

The analyses were conducted 102 percent of nominal power. The two percent is a typical number added for uncertainty. And the intent was originally to allow some space for measurement uncertainty recapture power uprating, which I understand is not going to happen.

There is also the consideration of steam generators which were replaced in 1996. And some of the analyses would be effected by the new steam generators. The new steam generators are fairly similar in design to the old steam generators in terms of size and volumes.

There was also a license renewal granted in 2004. And some of the analyses were considered back then and there's no need to look at them again this time around.

And concurrent with the EPU, we had the fuel transition which has been discussed at length. And this fuel transition does effect a number of the accident analyses. It's not simply the power uprating. There are changes in nuclear design parameters such as shutdown margin as Kent mentioned that would effect key analyses.

And then there's also the Tavg operating window. And this sets a range of Tavg for normal operation. And this required, for example, that accident analyses be considered at various points along this window to find a conservative initial condition.

And then two plugging, a maximum of two plugging of ten percent was assumed in the accident analyses. Before the EPU it was 15 percent.

This slide just lists the events that had been reanalyzed for the EPU for various reasons. And I don't think I'm going to go into these in detail. I'm sure you'll have questions. The time allotted to me was very short and I just wanted you to have a summary here and allow you to look through this and come up with some questions.

The one thing I would say is that this

event, this EPU, since there is a fuel transition involved and there are new steam generators required the analysis of more transients than might be expected in simply a straight EPU.

MEMBER WALLIS: Because there are very many events here, and the discussion of them takes up about a quarter of the SER, I think. And presumably these are the kind of events that limit what they can do in terms of power uprate.

MR. MIRANDA: Yes.

MEMBER WALLIS: And this is really where they are pushing the envelope in various dimensions.

MR. MIRANDA: Well, then would you like--

MEMBER WALLIS: And yet we don't seem to spend much time in this meeting discussing them.

MR. MIRANDA: I think there was a misunderstand.

MEMBER WALLIS: Isn't this the guts of the whole thing? Isn't this the basis for your decision; you look at all these things and they're pushing their limits in some ways, and then you decide whether that's acceptable or not.

MR. MIRANDA: That's right. I was told that to use maybe ten or 15 minutes. But if you want to take longer --

MEMBER WALLIS: Well, it seems to me that's the essence of the whole decision making, isn't it? Lots of the other stuff is peripheral.

MR. MIRANDA: Well would you like to take some more time and go through these?

MEMBER WALLIS: Well, what do we think?

CHAIRMAN DENNING: Well, i think what we would like to do is for those ones that are limiting, we'd like to look and see what your assessment is of those relative to what the applicant's assessment was.

MR. MIRANDA: Okay. Mark Finley had a good slide before indicating the limiting transients.

MR. MILANO: We've also got slides that came out of section 2.8 of the licensing report. And I'll provide those now.

MR. MIRANDA: Well, from my experience I would say that the loss of flow, accident, is the limiting transient in terms of DNB ratio. And that was one of the events that was in an earlier slide by Mark Finley.

In the license amendment request this is referred to as the flow coastdown accident. And that came very close to the DNBR limit of 1.38.

CHAIRMAN DENNING: You're looking at the table that was just handed out to us, is that true?

MR. MIRANDA: Yes.

CHAIRMAN DENNING: And that's in section 15.3.1 --

MR. MIRANDA: Yes.

CHAIRMAN DENNING: The flow coastdown.

MEMBER WALLIS: I notice some other ones we haven't seen before, like 15.2.2 loss-of-external-electrical load, which isn't all that uncommon an event. Your pressure is, again, remarkably close to some limit.

CHAIRMAN DENNING: Well, let' come back to that one. Let's focus for the moment on the one --

MEMBER WALLIS: Yes, I know. But I just said they're discovering other ones which are very close to the limit.

CHAIRMAN DENNING: Yes. Other ones, very good.

MR. MIRANDA: Yes. Would you like to go through these one-by-one --

MR. FINLEY: Actually let me correct. That loss-of-load result was shown on a previous slide. That was the one that was --

MEMBER WALLIS: Well, maybe I missed it.

MR. FINLEY: Yes.

CHAIRMAN DENNING: Thanks. Yes, let's

look at some of these key ones and just spend a few minutes on some of these key ones. And let's start out on the one that's 15.3.1, the one you pointed out there.

MR. MIRANDA: Okay. Okay.

CHAIRMAN DENNING: Okay. And so talk to us a little bit about that. And there are two numbers here. And explain to us again the 422V+ versus what the other number means.

MR. MIRANDA: Okay. For the loss of low accident there are three cases that were analyzed by the licensee. One is the partial loss of flow, which is the tripping of one reactor coolant pump. Then there's a flow coastdown accident, which is tripping of both pumps. And then there's another accident referred to as UF, under frequency. And this is the event where the grid frequency decays and eventually leads to a lose of reactor coolant flow, totally loss of reactor coolant flow. And this is the one that is the limiting event. It produces the lowest DNB ratio.

The analysis limit is 1.38. There are two numbers listed there. They're both for the Vantage Plus fuel. One refers to a typical cell, the other refers to a thimble cell.

A thimble cell is the assembly that

contains the control rods.

The limiting case, as indicated, is the 1.35 and that's for the Vantage Plus fuel. The 1.392 is for the OFA fuel.

CHAIRMAN DENNING: Now when you look at this and recognize the precision of the numbers and we established 1.38 as a limit, if they had gotten 1.38 would that have been unacceptable?

MR. MIRANDA: No, that would have been okay.

CHAIRMAN DENNING: That would be acceptable?

MR. MIRANDA: Yes.

CHAIRMAN DENNING: So anything that's like 1.381, that's better -- you know --

MR. MIRANDA: Yes.

CHAIRMAN DENNING: Anyway, the question is partly one of these extra significant figures that are clearly of no true significance. Are they important in this assessment?

MR. MIRANDA: They just show that they've met the limit.

CHAIRMAN DENNING: Yes.

MR. MIRANDA: So 1.1381 means that they met the limit. 1.38 would have been okay, too.

CHAIRMAN DENNING: 1.38 would have been okay?

MR. MIRANDA: Yes. And the reason is that there is a margin on both the number on the safety analysis result.

CHAIRMAN DENNING: Yes.

MEMBER MAYNARD: I personally don't have concern with coming that close to limit knowing that the criteria has margins already built into that. And that also the methodology that's reviewed and approved is also shown to show conservatism and make the approach.

If you wanted to change it where you went to the actual limit and demonstrated how much margin you had, then that would be a different process. But you basically have margin built into the criteria and an acceptable methodology that's been reviewed and approved.

MR. MIRANDA: Yes, I agree with that.

CHAIRMAN DENNING: Yes. And I recognize that the Staff has reviewed the basis for that. But I think that we'd like to get close enough to that to give ourselves some comfort that the uncertainties in this 1.38 value that we come up, the methodology to get to that, really do provide us the substantial margin to a true safety limit that the Staff's already gone through independently and convinced themselves of.

And also, we recognize that although that margin may be acceptable, it certainly is less than what it is in the current design. And trying to get a feeling for the risk significance is of going to the marginal results is something of interest to us.

MR. MIRANDA: It's kind of hard to gauge how much margin is lost by increasing the power level. You expect some reduction in margin intuitively, just because the power level goes up. But these are not exactly linear scales that you can just compare like apples and applies.

In this case the DNB correlation has not changed, but there are other instances where correlations do change from cycle to cycle. And you have different safety analysis limits to compare to.

For this particular case the flow coastdown accident involves an analysis by RETRAN to calculate the flow coastdown accident in the reactor coolant system and generates power level, reactor coolant system temperature, flow and other conditions. And these are then fed into a detailed core model, VIPRE, which has the fuel assembly and the dimensions and the pitch and all of that, including the thimble and the typical, including the OFA and the Vantage Plus fuel which actually calculated a DNB ratio for the hot rod. And that is the number that you find. That number is not from the bulk conditions calculated by RETRAN.

CHAIRMAN DENNING: And the Staff has reviewed these couple of codes and is there a safety evaluation report on that? How do you bless it through a safety evaluation report?

MR. MIRANDA: Yes. These methods have been submitted to the Staff as topical reports and they have been approved by the Staff in the past for other plants.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: And the approval didn't have conditions on it? It may be it's being used now for conditions which were not used for its approval before.

MR. MIRANDA: Yes, that's a good point. And that is something that the Staff has to review with every application that when an applicant uses an approved methodology, that they're using it within the limits of the approval. And that has been done.

CHAIRMAN DENNING: Okay. Did you want to

go back the to some of these other cases and look at those?

MEMBER WALLIS: What do you do when you see a number like, you know, 15.2.2 on the first page which has 2748.8 versus 2748.5? Does that raise a sort of flag with you that these are very close, I'd better go back and be sure that everything is okay, or do you just accept it?

MR. MIRANDA: Are you referring to --

MEMBER WALLIS: There's no criterion there.

MR. MIRANDA: Okay. Okay.

MEMBER WALLIS: There's no criterion.

MR. MIRANDA: The pressures? You're talking about the pressures then. Yes.

MEMBER WALLIS: I'm not sure. What are showing here by analysis limit and limiting case, what does that mean? An analysis limit means the criterion that you apply?

MR. MIRANDA: Yes. Yes. The analysis limit for peak pressure, for example, is 110 percent of design pressure. And that goes for the primary and secondary side.

MEMBER WALLIS: Presumably the 110 was not 109.9 or something. But that's what they've got, so whatever. It's very close.

MR. MIRANDA: Yes.

MEMBER WALLIS: Does that raise a flag with you and you go back and check into it in some way?

MR. MIRANDA: It raises a very small flag in the sense that, yes, I would see the number and begin to question it and say why is it so close. But then that leads to the review of the actual analysis that produced that result. And I would need to make sure that that analysis was conservative analysis, that it was conducted using approved methods within their limits and that the initial conditions that were used were in the conservative direction. And if I'm assured that those initial conditions were the appropriate conservative values, then I know that 2746.8 is really lower than that. And this is --

CHAIRMAN DENNING: Have you done some independent checking of these using those codes or did you go to the vendor? I'm sorry, you went to Westinghouse and you oversaw some calculations being performed.

MR. MIRANDA: Okay. As a matter of fact we went to Westinghouse November 1, 2 and 3. And Kent Wood and I and Len Ward were all there, and John

Nakoski as well. And we reviewed the calculations that were performed by Westinghouse for almost all of these accidents.

We also reviewed the guidance that Westinghouse uses internally for their analysts to be sure that they produce consistent analyses.

And we also requested that Westinghouse provide a copy of their LOFTRAN code at their local office in Rockville for use by the Staff to perform confirmatory analyses. And as a matter of fact, I did an analysis for the loss-of-external load. And my value came very close, within 2 psi of 2746.

MEMBER WALLIS: So the client or the utility uses RETRAN?

MR. MIRANDA: Yes.

MEMBER WALLIS: That's not a Westinghouse code. They would use a different code. I would be prepared to expect that if you use a Westinghouse code rather than RETRAN, you'd get a difference which was bigger than the difference we're talking about here between the limiting case and the analysis limit.

MR. MIRANDA: Well, RETRAN and --

MEMBER WALLIS: So using another code would give a different answer which might be over the limit, quite likely. Just as likely as not.

MR. MIRANDA: The two codes involved in, RETRAN and LOFTRAN. LOFTRAN is a Westinghouse code. And it was benchmarked -- RETRAN was benchmarked against LOFTRAN.

MEMBER WALLIS: That means that they're sort of about the same, but they don't give exactly the same answer.

MR. MIRANDA: That's right, they're about the same. And the results --

MEMBER WALLIS: So what you could do, is you got two numbers which are close together, you could say I want an independent opinion here. I want a different code to look at this. You don't do that sort of thing?

MR. MIRANDA: Well, we do. We use RELAP also. In case we didn't do the RELAP analyses on the non-LOCA events because we just didn't have the time. But right now RELAP is being used by Len Ward to perform small break LOCA analysis.

MEMBER WALLIS: But if you were in a hospital and you got some patient, and you weren't quite sure whether or not to do something, you know you might want a second opinion to confirm your decision in some way, you know.

MR. FINLEY: Mark Finley.

Just to respond to the one question. We didn't cherry pick, so to speak, in terms of the methodology. We made the decision up front to use the RETRAN methodology and that's what we stuck with for the non-LOCA events. We used LOFTRAN for the control systems, so a different functional area at Westinghouse. But we didn't look at the results of two different analyses with two different codes and pick the ones that was better.

MEMBER WALLIS: But the Agency has the choice of sometimes doing confirmatory analysis.

MR. MIRANDA: Yes.

MEMBER WALLIS: Did you pick any of these numbers as being so close that you wanted to see a confirmatory analyses?

MR. MIRANDA: Well, as I said before, I did not an analysis of the loss-of-electrical load using the LOFTRAN code. And the results I got were very close to the values that were produced by RETRAN.

MEMBER WALLIS: So you did do the --

MR. MIRANDA: I did that, yes.

MEMBER WALLIS: And what was the number you came up with?

MR. MIRANDA: I believe it's in the SER. For the loss-of-load.

CHAIRMAN DENNING: And that was with LOFTRAN THINC?

MR. MIRANDA: That was with LOFTRAN.

CHAIRMAN DENNING: And THINC?

MR. MIRANDA: No. THINC was not used in these case.

CHAIRMAN DENNING: It wasn't?

MEMBER WALLIS: So LOFTRAN is like RETRAN then? Well, maybe you could tell us after lunch or something if you're having difficulty finding it.

MR. MIRANDA: I don't know what that number is. The loss-of load event I did was for the overpressure case. The overpressure case, I believe, was 2525 something like that. And that was in another -- okay. Yes. That was to verify that the pressurizer safety valves and the steam generator safety valves were sized adequately. And that value was 2725, which was very close to Westinghouse's number.

CHAIRMAN DENNING: And when you worked with Westinghouse -- I'm sorry, you reviewed the Westinghouse analyses, in doing that did you look at inputs and outputs or was this verbal discussion with Westinghouse about them? Did you physically look at the input and output and do some cross checking of that?

MR. MIRANDA: Yes. Yes, we did. Westinghouse had available to us the analysts who performed these analyses for discussions. And the analysts brought along the calculations and we looked through the calculations at the inputs and the methods used. Yes, we did that for three days.

MEMBER SIEBER: But there is a fair amount of margin built into all of these just by the nature of where they come from.

For example in the loss-of-external-electrical load the design pressure of the coolant system, which is really what you're looking at, is 2500 pounds for this plant. Normal operating pressure is 2250. During this abnormal occurrence, I think this is an abnormal occurrence type event that's expected to occur perhaps as much as every year, the pressure you can go to is 110 percent of the design pressure by code. But that doesn't mean that that's the ultimate strength of the coolant system. The coolant system ultimate strength, there's tremendous margin between 110 percent of code design pressure and what the ultimate strength is. So that's where the margin really exists. And that doesn't mean don't do your best job to be under this. But it doesn't mean that when you calculate 2750 compared to a limit of

2750 that there's no margin left. There's plenty of margin left and it's built into the way the ASME code is designed.

CHAIRMAN DENNING: Yes. And that 110 percent of design pressure comes an ANSI standard 18.2 1993 for condition II events.

MEMBER SIEBER: Right.

MEMBER WALLIS: I guess what concerns me is the generic problem with codes. Whenever there is a conference on codes, now people are always talking about the user effect; that different people using apparently the same code to analyze exactly the same thing, apparently using the same methods and the same inputs, can often come up with different answers. And the utility has, of course, the incentive to come up with a favorable answer. And it is a user. And so there has to be some careful examination that there hasn't been some user effect which has enabled this code to come very close to whatever is required as the regulatory limit. I think you have to be very careful to ensure that does not happen.

MR. MIRANDA: Yes.

MR. DUNNE: Jim Dunne.

I think one of the things Westinghouse tries to do to eliminate some of the variability associated with the analysts is they have these instruction guidelines for all these different accidents that basically tell the analysts these are the assumptions you have to make and not leave it up to the individual analyst to make that assumption himself.

So for a lot of the key inputs Westinghouse has basically standardized internally the assumptions their analysts have to make to remove that variability. And that was, I think, one of the things that the NRC reviewed when they did the audit of Westinghouse in November of last year.

MR. MIRANDA: That's correct. And these analysis standards, as they're referred to at Westinghouse have been existence since 1972. I know this because I wrote the first one.

MEMBER WALLIS: So you maintain there's no user effect? If we had two different analysts do the same thing, they come up with the same number?

MR. MIRANDA: Of course there's a user effect, but these analysis standards are designed to minimize that.

MEMBER WALLIS: So how big is the minimum? Is the minimum of variance of 10 percent -- you can go on forever about this. But I'm sure people are aware of this and they've done something, but I just don't have any idea of the dimensions of the uncertainty that remains.

MR. MIRANDA: Part of the procedure is that the analysts when calculating the inputs for the codes, it has to follow certain procedures and use certain values that are dictated for that plant. And if he deviates from that procedure for any reason, he's instructed to state the reason and this is reviewed when the calculation is checked by peers and management.

Sometimes it's necessary to deviate just because of the plant design. And the analyst should have a good reason for the deviation.

CHAIRMAN DENNING: I think you should bounce back now to the continuation of the presentation that you're on and we'll move forward through that.

MR. FINLEY: Okay.

MR. MIRANDA: This is a listing of the events that the Staff has received analyses for from the licensees. For various reasons, as I said before, in addition to the power uprating.

This is followed by events that were evaluated. And the reasons for these events for being evaluated stem from these are either not applicable or they're bounded by other events. Usually they're bounded by other events and a new analysis was not necessary.

And this is also stated in the safety evaluation which events are evaluated, which are analyzed. And in the case of events that are evaluated, why it was not necessary to do the analysis.

ATWS was also considered. And this event, I thought it was important to review the analysis for this event. There was very little provided by the licensee, by the way, in their submittal concerning ATWS. They said yes we meet the criteria. And I requested to see the analyses and the calculation. And they were provided to me.

I considered it important because the Ginna plant has new steam generators, B&W steam generators installed in 1996. And I was afraid that they might be trying to use the Westinghouse generic analyses that originally covered Ginna, which had a 44 series steam generators. Without the 44 series steam generator, I believe that the generic analyses no longer applied. And it turns out that Westinghouse had performed an entire new analysis using the new steam generators at the power level of 1817 megawatts. And they obtained an acceptable result.

And this 3200 psig is the ASME level stress limit for the weakest component in the RCS, which I believe is the --

MEMBER WALLIS: Can I ask you about ATWS? Now other operator actions that occur during an ATWS event which influence the outcome?

MR. MIRANDA: The ATWS event is analyzed without operator actions?

MEMBER WALLIS: Without?

MR. MIRANDA: Without, yes.

MEMBER WALLIS: So the operators are not likely to take actions which would change the number of this peak pressure?

MR. MIRANDA: The peak pressure occurs at about 2 minutes into the transient.

MEMBER WALLIS: And by then the operators haven't done anything?

MR. MIRANDA: I don't believe an operator would have a chance to do anything at 2 minutes.

MEMBER WALLIS: This is very different from a BWR ATWS where the operators are expected to do things.

MR. MIRANDA: As far as new spent fuel

storage, Ginna had received an amendment December 2000 which permits the credit for soluble boron in the spent fuel pool. And they satisfied also all of the provisions of the 10 CFR 50.68.

MEMBER WALLIS: Well the spent fuel pool, rather surprised and maybe not a surprise if I'd know the history of these things. But originally it was capable of taking 210 assemblies and now it seems to be capable of taking -- it has a spec limit of 1879 assemblies. So somehow the capacity of the spent fuel pool has been increased by a factor of nine.

MR. DUNNE: This is Jim Dunne.

I think I can explain some of that history.

The 1879 number assumes consolidation of fuel assemblies into consolidated canisters. We take two fuel assemblies approach --

MEMBER WALLIS: Well, it's the same the pool. It's the same pool.

MR. DUNNE: The same pool.

MEMBER WALLIS: So you found ways to increase the capacity by a factor of nine?

MR. DUNNE: Right. We've gone through I believe three reracking of our spent fuel pool since the original construction. Our last rereacking was in

1998, I believe. And the actual number of storage locations we physically have in the pool right now is up around 1321 fuel assemblies basically. And part of that involved going to boroflex fuel assemblies I think in the '80s.

MEMBER WALLIS: Yes.

MR. DUNNE: And then in the 1990s we inserted a number of borated stainless steel fuel assemblies --

MEMBER WALLIS: So there must have a considerable conservatism in the original design then that you can do this.

MR. DUNNE: Yes.

MEMBER WALLIS: But now you probably are getting close to a real limit?

MR. DUNNE: We are getting close to a real limit, that's correct.

CHAIRMAN DENNING: And initially you weren't allowed to take credit for boron in the water.

MR. DUNNE: Right. And I think the reason why we took credit for the boron is the boroflex issue and degradation of the boroflex which was either boron poison. But because it's degraded and really not assume it's there, we needed to --

MEMBER WALLIS: But we're talking about

margin. You're below .95 aren't you, in this case?

MR. DUNNE: I believe when we borated, typically we're well below.

MEMBER WALLIS: Way below it?

MR. DUNNE: Yes.

MEMBER WALLIS: Right. So that's not one of these things where you're close to the limit at all?

CHAIRMAN DENNING: You take burn up credit?

MR. DUNNE: I'll let our fuel engineer answer that one.

MR. VERDIN: Yes. This is Gord Verdin.

We do take burn up credit and also years of decay due to plutonium decay. And we also have criterion as to the reactivity categories of assemblies that we can place adjacent to each other. That's how we make up for the loss of the boroflex. We don't credit the boroflex at all.

MEMBER SIEBER: But the original rules didn't give you a burn up credit, right? And so that's why the spacing was so big?

MR. VERDIN: Yes. The other thing was that Ginna back in the 1970s, we actually shipped three regions of the fuel to the West Valley

Demonstration Project. There was no intention to leave the fuel in the pool for any period of time.

MR. MIRANDA: Okay. These are the results for the large break LOCA using the ASTRUM methodology. And you've seen these numbers before.

And finally --

MEMBER WALLIS: That's very conservative 124 runs. Because the PCT seems to be the one which matters. And so you could do the number of runs appropriate to one criteria. And if you were really satisfied that that was the one that --

MR. MIRANDA: Was there a question?

MEMBER SIEBER: That's not a question.

MEMBER WALLIS: I'm noting that it's only the PCT which seems to come near the limit, so that's the one that governs.

MR. MIRANDA: The Staff is still evaluating the small break LOCA analyses and the long term cooling and the boron precipitation. And these are independent analyses being conducted with RELAP. So we don't have the results of those just yet.

MEMBER WALLIS: So maybe this is where we get an example of one issue, small break LOCA, which we can go into in some detail instead of rushing through all of these other ones.

CHAIRMAN DENNING: Of course, the problem is that one's going to be fair from illumination apparently based on -- so I'm not sure it's going to be--

MEMBER WALLIS: So why are we waiting so long to hear something which isn't so important? I was thinking that you might -- that would be your opportunity to show how you go in depth into some of these things because you have more time then.

MR. MIRANDA: John Nakoski will address that.

MR. NAKOSKI: Yes. This is John Nakoski. I'm the PWR Reactor System Branch Chief.

Our intention is at the next Subcommittee meeting where we discuss Beaver Valley to go through what we have done, our confirmatory calculations and the review that we've done for the small break LOCA and long term cooling.

Our concern was to develop reasonable assurance that the analysis method and assumptions and the results are consistent with our expectations and satisfy our acceptance criteria.

You may be aware that we have a concern in long term cooling for a small break LOCA, that we have reasonable assurance that boron precipitation is not an issue that would impact the Staff's findings. We're evaluating that issue. Ken Ward is doing independent confirmatory calculations. But we have not finished those yet.

MR. MIRANDA: In conclusion, the Staff believes that the accident analysis both analyses and evaluations submitted by the licensee, have met the acceptance criteria short of the small break LOCA and the long term cooling of boron precipitation which are still under review.

MEMBER SIEBER: I have a question that goes back to the issue of peak clad temperature and design trends through the years. It seems to me that the trend by fuel designers has been to make more rods but smaller rods to lower the linear power density. And in doing that, that had a positive impact insofar as lowering the peak clad temperature.

I look at the fuel design trend for Ginna, they're going in the opposite direction. And I presume, you know, they now have bigger, heavier rods, reduced flow, a change in the moderation ratio you know whether you're over moderated or under moderated. And that probably had some negative -- that kind of a design implementation had some negative effect on peak clad temperature, even though you got a lot of margin, I would think that would come out that way? Am I thinking about this in the right framework or not?

MR. FINLEY: Let me ask Jeff Kobelak to respond to that, if he would.

MEMBER WALLIS: And you told us that using the old method you got to 2070 something.

MR. KOBELAK: Yes.

MEMBER WALLIS: What would you get to using the old method before the EPU?

MR. KOBELAK: We did not run any cases.

MEMBER WALLIS: Well, someone must have calculated before because there was a submittal before. It must be in the record somewhere what they were calculating. But they were using some other method even different in those days. Were they using Appendix K or something so we can't make comparisons?

MR. KOBELAK: You mean like with pre --

MEMBER WALLIS: Well, has the peak clad temperature gone up significantly as a result of the EPU? I think that's sort of the question.

MR. VERDIN: This is Gord Verdin.

There has been some miscommunication. The 2087 is the current best estimate LOCA with the safety methodology at the current power level.

MEMBER WALLIS: Without the EPU?

MR. VERDIN: That's correct.

MEMBER WALLIS: So with the EPU if it goes up, you might have found yourselves up to the limit with the core methodology?

MR. VERDIN: Correct. And as we've stated, they didn't actually perform those evaluation at EPU.

MEMBER WALLIS: So we can't really make comparisons. But in fact we might have the implication that you used this new methodology because the old methodology was not giving the right answer?

MEMBER SIEBER: Or you think it might not.

MEMBER WALLIS: Or you thought it might not.

MEMBER SIEBER: But whether you thought that or not is irrelevant.

MR. FINLEY: Certainly with respect to large break LOCA one of our objectives at the outset was to use the new BE LOCA methodology to demonstrate we had the margin in that analysis for the uprate. Yes.

MR. NAKOSKI: And regarding the fuel design, yes, I would say that's an accurate statement. As you increase the number of rods and you lower the linear heat rate per rod, that does kind of benefit the PCT.

MEMBER SIEBER: Right. But this design change in the fuel goes the opposite way, which puts more pressure on PCT than you otherwise would have had and you did it for other reasons. That's sort of the way I piece all this together. And you still meet the limit.

MR. NAKOSKI: Yes. And the prior fuel was also 14X14.

MEMBER SIEBER: Yes.

MR. FINLEY: That's correct. Right.

MEMBER WALLIS: Well, this would be useful to the Committee to get some idea of is this statistical approach to LOCAs one of the keys to allowing power uprates of this magnitude.

MEMBER SIEBER: Yes.

MEMBER WALLIS: I think that's an important issue for this Committee to think about. Is that true? Is it true that the statistical approach is enabling this to happen?

MR. FINLEY: Yes. That is one of the factors that enables this, yes.

MEMBER WALLIS: Yes.

CHAIRMAN DENNING: Are you actually done with your part of the presentation and we would have gone to the source terms and radiological consequences next? Is that where we stand?

MR. MIRANDA: Yes. I'm done with my part, yes.

CHAIRMAN DENNING: Yes. So I think if it's--

MR. MILANO: Our presentation is relatively short in that area. And I think it would probably be, if you don't mind, you know we could go through and do that and then have our break.

CHAIRMAN DENNING: Would you prefer to do that for some reason?

MR. MILANO: Yes. That's what I would prefer to do.

CHAIRMAN DENNING: Then we'll go ahead and do it that way then.

MR. MILANO: Thank you.

Brian?

MR. MILANO: This is Brian Lee. he's from our Accident Dose Branch and he's going to make a presentation.

MR. LEE: Yes. Good morning. I'm Brian Lee, a reactor systems engineer in the Office of Nuclear Reactor Regulation. Also here with me today is a senior member of staff from the Accident Dose Branch to provide a guidance with me on this review.

The Staff reviewed the source terms for rad waste system analysis and reviewed Matrix 9 of the review standard and section 2.9.1 of the EPU safety evaluation.

The radiation sources and the reactor coolant were analyzed for EPU conditions under the same methodology previously used in the Ginna design basis, which is consistent with the GALE code that is considered in the Staff's review.

Based on the maximum reactor coolant activity product, the staff determined that the EPU is acceptable as it continues to meet the requirements of the 10 CFR Part 20, 10 CFR Part 50 Appendix I, and the General Design Criterion 60.

With respect to the design basis accidents radiological consequences analysis, the Staff review Matrix 9 of the review standard and section 2.9.2 of the EPU safety evaluation.

The licensee had previously reanalyzed all design basis accidents with the implementation of a full scope alternate source term. The current revised dose analysis assumed proposed EPU conditions at a reactor core power of 1811 megawatts thermal including a two percent power measurement uncertainty and followed the guidance of Reg. Guide 1.183.

The Staff took a look at all design basis accidents in its review. The LOCA, the fueling handling accident and the tornado missile accident, which is not considered to a design basis accident but is a part of the Ginna's licensing and design basis were all reanalyzed due to the sources and the fuel increasing at the power increase.

The main steam line break, the steam generator tube rupture, the locked rotor accident and the rod injection accident were all reanalyzed due to the change in its mass and energy release.

The licensee assumed a control room isolation for all design basis accidents with a filter recirculation flow of 5400 cubic feet per minute. A 300 cubic feet per minute unfilter in leakage was assumed and has been validated by a tracer gas in leakage test performed in February of 2005.

CHAIRMAN DENNING: When you say confirmed, actually didn't they show that it was substantially lower?

MR. LEE: Yes, they did. Actually, their number with one train running the highest load was 21 cubic feet per minute.

In conclusion the licensee has adequately accounted for the effects of the proposed EPU. All design basis accidents meet the exposure guideline values cited in 10 CFR 50.67 and the acceptance criteria in the Standard Review Plan 15.0.1 for both offsite and in the control room.

The Staff finds that the proposed EPU is acceptable with respect to the radiological consequences of design basis accidents.

And that concludes my presentation. I can take any questions if you have any.

CHAIRMAN DENNING: Questions? No. Thank you very much.

Okay. We'll say it's 12:30 and we'll resume here at 1:30.

MR. MILANO: At 1:30 is there an expectation that we would continue on with anything with regard to the safety analysis or would we be going to the next item on the --

CHAIRMAN DENNING: We'll go to the next item on the list.

MR. MILANO: Okay.

(Whereupon, at 12:27 p.m. the Subcommittee 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.

MR. MIRANDA: Could I have your attention, please.

Okay. We're going to get started this afternoon's presentations. We're going to start with the risk evaluation summary. And it'll be a two parter. It's going to start out with Ralph Cavedo with Ginna presenting his and we'll follow it with Donnie Harrison from the NRC Staff.

Thank you.

MR. CAVEDO: Hi. My name is Rob Cavedo. And I've been doing probability risk assessment for 17 years. I'm here to present the results of the risk evaluation, results and insights.

CHAIRMAN DENNING: You don't have to apologize right at the beginning for saying your risk analyst.

MEMBER SIEBER: You can wait a little bit.

MR. CAVEDO: Before we go into the original agenda, I just wanted to a tie in to how risk assessment is used to evaluate actual changes in margin.

CHAIRMAN DENNING: Move in a little closer.

MR. CAVEDO: I'm sorry. I like to move around. I can't do that. I need a wireless microphone.

So I'd like to tie in to how the actual risk evaluation relates to actual changes in margin versus calculated changes in margin that you've been referring to a lot.

So when you do a typical design basic calculation like loss-of load you'll go through and evaluate the lift setpoints of a bunch of relief valves, for example. And when you determine what you can live with in the calculation, you raise that setpoint until you reach the calculational regulatory limit. But from a risk assessment perspective that's where we go back and look at was that change acceptable. And we look at real plant changes. So if you change an actual setpoint, that's factored into the risk evaluation. And that's where the rubber hits the road and that's where we evaluate what the actual loss in margin is.

So I think there is a tie in. We want to have as much operational flexibility as possible, but we want to evaluate what the real change in risk is and make sure that it's acceptable.

To perform the risk evaluation we looked at the changes in initiating event frequency, success criteria, equipment failure rates, operator restoration times. And we used that to calculate the change in the core damage frequency in LERF for internal, external events and shutdown.

MEMBER SIEBER: Now your success criteria is still a go/no go situation?

MR. CAVEDO: Well, the success criteria in a very similar fashion to how the design basis calculations is an iterative process. So for example let's say that you're trying to determine the feed and bleed success criteria. Well, you know a fixed set of equipment that you would like to use and you keep on changing the time that it takes the operator to initiate that action until a certain set of equipment is satisfied. But from a PRA you go beyond just that and say, okay, let's say you had one less PORVs or you had fewer charging. Then you have less time to implement the action. So it's all factored in by calculation to determine time available to perform an action, or in some cases it's break size. So you might go in and let's say it's a large break LOCA, what set of equipment do you need. Let's say that it's medium break LOCA, well you determine those break transition points in terms of piping size based on the amount of equipment that's available. So you turn it into a go/no go problem but it is calculated based on the range of parameters that you examine.

MEMBER SIEBER: On the other hand if you have a pump, for example, that is operating right when it's about to lose MPSH, you know maybe you're in recirculation and your strainer's partially clogged. You would count that pump if it doesn't meet the success criteria as inoperable as opposed to a pump that may be chugging and not pumping as much as you would like or as much as advertised?

MR. CAVEDO: Right. If the design basis criteria for loss of net positive suction had a sum value, then we might use a different value in the PRA for determining when that pump will actually be failed. Not inoperable, but unavailable.

MEMBER SIEBER: Yes.

MR. CAVEDO: So we use a terminology as far as the design basis way that you say that it can satisfy the design basis criteria and it's operable, we consider things available to perform their function or not available to perform their function under the given set of circumstances.

MEMBER SIEBER: Yes. I think that's one of the drawbacks, at least in my own mind as to how well PRAs model what's going on in the plant.

And another one is that PRAs do not have a lot of phenomenological models built into it. And it's relatively simple. And I guess for the purposes that it's being used here by you and by the staff, it's okay. On the other hand, there is plenty of places where PRA modeling could be improved, you know.

MR. CAVEDO: There's plenty of places where any modeling could be improved, no matter what you're talking about. That's definitely true.

MEMBER SIEBER: Right. That's my speech for this hour.

MR. CAVEDO: I mean the Chairman talks about when he talks about PRA and you say is PRA good or bad. And then you say well what are you comparing it to? Design basis. And we all know what the vulnerabilities are with design basis. So it's not whether it's the perfect tool; no one is saying that PRA is the perfect tool. It's just saying it's -- well, in my view, it's a better tool.

So you have to maintain your design basis margins because that gives you the framework which to evaluate things, but you do need to evaluate what the changes in risk are to make sure that you're operating appropriately.

Okay. So we evaluated the impact on those elements to calculate the core damage and load changes on internal events, external events and shutdown risk.

There are no PSA initiators as a result of this. Now the reason I mention PRA initiators is because that's different than design basis initiators. Most of the time when you look at a phenomenon, considering the huge number of initiating events that are considered in the PRA, you don't have to make a new initiating event. You just adjust the frequency based on changes as a result of the EPU, for example.

So if we had increased flow in the feedwater system and it was beyond certain limits, or not beyond certain limits but it was approaching certain limits, then we might increase the failure rate of that feedwater piping to account for that.

As far as success criteria adjustments, which was a majority of the risk. So the small part of the risk was the initiating event frequency changes, the vast majority of the risk changes was due to the change in success criteria. And we used a thermal hydraulic code to evaluate that. And the major impact that we came up with was bleed and feed.

We went from pre-EPU to post-EPU, a case where you had to have two PORVs for bleed and feel depending on the availability of charging. So we noticed that was the biggest success criteria change that we had.

We did also look at equipment failure rates, but we found is due to the programs that are in place there is not much impact on equipment failures from an immediate mitigation standpoint of an accident. So PRA analysis works 24 hours following the plant challenge. But from a long term perspective because equipment can be operating with less margin available, there is a likelihood that you will have initiating events as a result of the reduced margins, an increasing in the initiating event frequency.

MEMBER SIEBER: Do you change your PRA to account for that?

MR. CAVEDO: Yes.

MEMBER SIEBER: Because I think that's an important thing.

MR. CAVEDO: Yes, we do.

MEMBER SIEBER: Okay. And how do you do--

MR. CAVEDO: Yes. We went through a --

MEMBER SIEBER: How do you do it?

MR. CAVEDO: Say again?

MEMBER SIEBER: How do you do it? By changing the failure rate?

MR. CAVEDO: That's exactly right. We

change the frequency as a result of that. So what we'll do is we'll do a detailed review of the engineering reports. We'll look at where margin is lost. And then we will adjust frequencies based on that.

Now, of course, how do you predict exactly how they're going to be degraded.

MEMBER SIEBER: Right.

MR. CAVEDO: That's probably the next question that you're worried about. Well, there's no way to predict perfectly what's going to happen. And so with any good risk assessment what you have to do then are sensitivity studies. You look at how all the parameters that are sensitive to this will change as a result of increasing by a factor of two or some metric so you can determine what's sensitive. And then we had, as Dave mentioned, a detailed sequester review where we get everybody together and we talk about it. And we reviewed with the project manager and members of licensing and others all of the parameters that were sensitive. And they were comfortable that those parameters were not going to be adversely impacted by EPU.

So the sensitivities give us a feel for not only what the changes are going to be, but to make sure that we're focused on the right areas.

MEMBER SIEBER: So you don't really have data? This is a judgment call based on your --

MR. CAVEDO: Yes. It's almost exclusively a judgment call because, as you said, data even if you had data for another plant, that might not be applicable to the Ginna plant. And so you could try to do some Basian update, but the sample is so small that it would really not be very relevant, so --

MEMBER SIEBER: Right. I think that you realize what the pitfalls are?

MR. CAVEDO: Yes.

MEMBER SIEBER: It's not clear that there isn't some better way to handle it, but it dominates your lack of data.

MR. CAVEDO: And that's why you have to do uncertainty analysis, to make sure that you compensate for your lack of predictability in what's going to happen by looking at -- let's say it's a little bit worse than you think, or let's say it's this; how much does that change the result and would that still be acceptable? So we did a ton of uncertainty analysis to give us comfort that we were still making the right decision.

MEMBER SIEBER: Very good. Thank you.

MR. CAVEDO: You're welcome.

So as I said, the major impact was a change in operator response time. And as was mentioned on a previous slide, obviously the higher decay heat reduced most of the operator response times. And the most important impacts that we noticed was the reduction in time to recover from a loss of shutdown cooling during reduced inventory. And we'll talk about a plant change that we're proposing to help offset that risk.

And the next largest one was the amount of the loss of time to recover from a loss of decay removal during a loss of offsite power. And then the one to recovery from a turbine driven AFW pump on a control room complex fire. And so you'll see that the modifications that we're talking about or the plant changes that we're talking about reflect these areas.

So here are the results, a sample of the results. This isn't all of them. If you actually looked in the submittal, you'd see that we evaluated all of the actions that could change as a result of the reduction in operator response time due to the increased decay heat. But this just gives you a nice little smattering of what changed.

And the important thing to look at here is when you're looking at these times and you go, oh, this is a bigger change in time than the percent change in power, how could that possibly be? Well, these are diagnosis times. So it takes a certain amount of time for an operator to go through a procedure. And that's going to be sometime, ten minutes or whatever it is. So if you reduce the overall time by 17 percent or whatever the calculation shows, because we actually get more margin in the steam generators it's a little cooler, so there are some things which offset each other. But overall you would expect things to be a 17 percent. But because of that subtraction you actually can see bigger percentage changes than you would expect just based on the nature of the power uprate. And that was all factored into the evaluation to calculate what the impact was.

MEMBER WALLIS: So are the changes in CDF all due to operator time factors?

MR. CAVEDO: Could you say again?

MEMBER WALLIS: Are all the changes in CDF due to these changes in time available for operator action?

MR. CAVEDO: No. The majority of the CDF, and I've produced a chart in the submittal --

MEMBER WALLIS: It seems to be in these EPUs that the hardware changes don't make any difference?

MR. CAVEDO: Well, we're going to get to that in a little bit. But the changes that they made actually helped to preserve a lot of the margin. If it wasn't for that, then we would have had a much bigger risk increase.

CHAIRMAN DENNING: I wanted to make sure I fully understand the table. What's the right hand column, the steam generator water level at trip?

MR. CAVEDO: Well, I could have presented a column with steam generator water levels at other demarkation points. But obviously the more water that you have in the generator at the time of the trip, then the more time you're going to have available to do that. And that's going to damp the impact of these changes. So I just wanted to put that this is at the low level water trip and so these are the conservative numbers. If you look at numbers at a different water level, then you would have more margin.

CHAIRMAN DENNING: With regards to these particular events, can you tell us what the conditional failure probability was for the base time versus the EPU time? How much of the failure probabilities changed?

MR. CAVEDO: Well, for example for the bleed and feed where you had no charging pumps and a single PORV available, it went from -- I don't remember the specific number whether it was a ten percent chance of failure to guaranteed failure. So that was one of the ones where it went from a reasonable likelihood the operator would succeed to there's not enough time available to perform the action.

CHAIRMAN DENNING: Okay.

MR. CAVEDO: I did provide all this information in the submittal. And if you want me to, I could look up any specific action that you're curious about, but I don't remember off the top of my head all the changes.

CHAIRMAN DENNING: But that's the fourth one down, is it?

MR. CAVEDO: That's the one where operator fails to align bleed and feed given a single PORV and no charging. That's the second line down.

CHAIRMAN DENNING: Ah, yes. Oh, this is the single PORV?

MR. CAVEDO: Yes. Where it's both PORVs they're actually both achievable, so it was just a change in failure probability. But with the single PORV and no charging, it was -- oh, you've got the chart there.

So single PORV no charging it went from -- well, that was the one that went from guaranteed failure. So there was a 09.7 percent chance of success pre-EPU. With post-EPU it went to guaranteed failure.

MEMBER WALLIS: Just by going to 15 minutes time?

MR. CAVEDO: Yes.

MEMBER WALLIS: I mean, he can't do anything in 15 minutes?

MR. CAVEDO: Well, there's always the chance that the operator could move outside the procedure or faster than the procedure and achieve a success. But we did tabletop exercises with operations to find out how much time it takes to get to those particular. And it was -- they actually might have been able to do it, but it might have been like an 80 percent chance. And we don't use failure likelihoods. If they're over .5, we typically don't use them for noncurve type recoveries.

Does that answer your question? And thanks for this.

CHAIRMAN DENNING: Yes.

MR. CAVEDO: Okay. And then the next thing we have are the actual results of the EPU change in terms of the internal and external events breakdown. And you can see from this it's about a net change of 7, E-06 for core damage and you can see what the LEF changed. Just do the substraction there.

And the percent change in core damage, it actually went up. If we didn't do any modifications or procedure enhancements or improvements to the plant, then the core damage would have gone by 12 percent and the LERF would have gone up by 10 percent.

CHAIRMAN DENNING: Can you help us a little bit on what are the principle contributors on fire, for example?

MR. CAVEDO: It was the turbine driven AFW pump on the low steam generator water level. So it's a control room complex fire type situation where, of course, there's not much indication available and the turbine driven pump is an important means of mitigating that event.

CHAIRMAN DENNING: Yes.

MR. CAVEDO: And we are doing modifications in plant improvements along to help support that. So that's not reflected in these numbers. These are the numbers without those improvements in place.

CHAIRMAN DENNING: Now are those plant improvements the ones we were hearing about at the very introduction about things that are going to happen that would be risk reducers?

MR. CAVEDO: Yes. And I have another slide that talks, and you can see what the specific impacts are of those changes.

CHAIRMAN DENNING: Oh, good.

Does the pressurizer volume appear as an issue on any damaged states?

MR. CAVEDO: Yes. It's not a risk significant issue, but all the stuff that was mentioned in Mark's evaluation, that's all been factored into the risk assessment; the change in boron precipitation, the difference in the pressurizer level, the change of the loss-of load parameters. All of those are factored into the risk assessment. So we did consider increased PORV challenges as a result in the change of the pressurizer configuration. And we did consider slightly increased PORV challenges as a result of loss-of load because above 50 percent it was going to happen anyway and below 10 percent it wasn't. And so we figured out what fraction in between the

PORV would be challenged and we figured out what fraction we operated in that plant configuration. So all of that is factored into the risk assessment. But those issues did not play the most significant role. It was all decay heat removal. Change in the operator response time, I mean it's critical operator response time. And so that was the vast majority of the risk increase was as a result of the reduced time for operator response. But all of that information was factored in explicitly in the risk evaluation.

CHAIRMAN DENNING: With regards to the potential for vibrational modes of failure of equipment that did not occur that are introduced, is there any contribution as you see it from that?

MR. CAVEDO: The initiating event contribution did factor in changes in the vibration. It is our expectation that with our programs in place we are not going to see a risk impact. But until the programs come to fruition, it's obviously when you first achieve that state there may be some degradation. So conservatively we increased the initiating event frequencies based on the items that were mentioned in the engineering report. And it was all judgment based, but then as I said we did the uncertainty evaluation to see what the impact would be possibly.

CHAIRMAN DENNING: So you introduced the initiating event frequencies for particular components that presumably would have failed?

MR. CAVEDO: No.

CHAIRMAN DENNING: No?

MR. CAVEDO: We did initiating event frequencies for whole systems. For example, we would increase the loss of feedwater frequency if there was a vibration concern in that whole system. So it wasn't done from a post-trip mitigation standpoint. It was done as an accident initiation.

CHAIRMAN DENNING: Yes. But you did it as a system frequency initiator?

MR. CAVEDO: Yes. At a initiating event level. And the initiating event are larger than just a component level. The component might not necessarily actually cause an initiating event. There might be actions that could be taken to mitigate that. But we did it at the system level.

CHAIRMAN DENNING: Thanks.

MR. CAVEDO: Okay.

MEMBER WALLIS: I'm a bit confused here. What do you mean? You seem to have said that you increased the risk and then you do some modifications which would decrease the risk so that eventually less than it was before the uprate?

MR. CAVEDO: Well, we're jumping ahead, and that's a great lead in.

MEMBER WALLIS: So I don't quite understand, what's the difference between --

MR. CAVEDO: These numbers don't include any of the plant improvements that we're going to assess later on.

MEMBER WALLIS: So these include simply hardware changes or something?

MR. CAVEDO: This is just the plant improvements that aren't risk based.

So the first thing we did is we did this risk evaluation based on the operational plant improvements that were going to be done, like the condensate booster pump, the standby AFW pump; all of those are factored into these numbers to make sure that we have the same operational configuration which, that obviously provides some risk benefit. If we wouldn't have done that and now a booster pump loss would cause a trip immediately, then that would be a risk increase associated with that. But that was already within the scope to handle that. We didn't consider that from a risk perspective.

What we then did was that once we achieved--

MEMBER WALLIS: But this business we were talking about earlier about the operator fails to do things. That has changed. That's figured into this slide here?

MR. CAVEDO: That is the primary basis, the operator change in times to a 12 percent increase.

MEMBER WALLIS: The primarily influence of all this is the operator time to --

MR. CAVEDO: I don't remember the exact number, but it was something like 63 percent and then initiating events were 27.

MEMBER WALLIS: Okay.

MR. CAVEDO: So there you have. He's got the numbers better memorized than I do.

MR. FINLEY: Mark Finley again.

Just to interject, and what Rob is talking about sort of reflects the timing of how this went. This risk evaluation to this point was done early enough for Rob to identify to us where the risk vulnerabilities were and identify what procedure changes and other modifications might help counteract that. Okay. So this is where we were before he made the recommendations and before we added those additional mods to the scope of the uprate.

MR. CAVEDO: So at this point this is what was within the original scope of the uprate. But our management was very interested in preserving our overall margin and keeping our risk levels low. So they said take a look at the most risk significant contributions among your calculations and come up with some procedures enhancement or modifications that could reduce the risk to below the pre-EPU level. And so we did a very exhaustive study and cost benefit analyses with the risk benefit that was available. And we came up with some options. And here are the options that we came up with.

Well, first to explain the chart that's there. The first column shows you the pre-EPU risk, and if you look back on the previous one, you see that's just the sum of the internal/external events and shutdown. And then you see what the risk would be, which is also the same as on the previous chart, post-EPU. And then you can see how much the risk goes down as a result of the plant improvements that we're planning. And the aggregate of them is just the last line.

So the SI is -- for our Appendix R evaluation we were limited by our existing procedures to just basically crediting the alpha charging pump. But we're doing improvements to make sure that we can credit the safety injection pump for mitigation during our control room complex fire, for example. And so this gives us some risk benefit.

And you remember that was one of the risk significant issues was fire. And then the next risk significant issue, actually the most risk significant issue that we found, was during reduced inventory it was possible that air operator control valves on loss of air or power could fail open and cause vortexing on the RHR pumps. And that, of course, in reduced inventory there's not much time available to recover. So that could lead to negative consequences. So we're doing actions to make sure that even on the loss of power or air, the valves will not fail to the point where you'll have that vortexing problem and your RHR pumps will fail. So that, as you can see, was another risk benefit.

And then a modification that we're doing is to provide backup air to the charging system so it can maintain --

MEMBER WALLIS: Well, I'm lost. I'm lost. Where are these CDF numbers?

MR. CAVEDO: This column is the CDF and

these are the changes that are --

MEMBER WALLIS: Those are changes in CDF? No.

MR. CAVEDO: Yes.

MEMBER WALLIS: They're awfully big.

MR. CAVEDO: So this is what the base changes -- so this is the base change in CDF.

MEMBER WALLIS: That's what you had on the previous slide?

MR. CAVEDO: And that' what I had on the previous slide. Exactly. And then if you do the safety injection --

MEMBER WALLIS: You can get it down lower?

MR. CAVEDO: Exactly. Then it goes down by that much. And if you do just the shutdown --

CHAIRMAN DENNING: You're saying you could get it down by that much. But you meant it goes down to that much.

MEMBER WALLIS: To that much.

MR. CAVEDO: Yes, it goes down to that much. Sorry.

MEMBER WALLIS: These are separate items them?

MR. CAVEDO: Yes.

MEMBER WALLIS: If you only do one of

these?

MR. CAVEDO: Yes.

MEMBER WALLIS: But suppose you do them all?

MR. CAVEDO: That's the bottom line.

MEMBER WALLIS: Oh the bottom line is the sigma. I was just wondering when we'd get to that.

MR. CAVEDO: The bottom line is this one right here.

MEMBER WALLIS: That's the sum of the whole lot, of three? Okay.

MR. CAVEDO: Yes. And that's actually a good lead in to the next slide, if you wanted to go there.

CHAIRMAN DENNING: Well, the only thing I've got to say is that we can criticize for lots of things, but we can't criticize you for the mentality of going back and looking at ways to improve safety.

MR. CAVEDO: Yes.

CHAIRMAN DENNING: So I certainly commend you on that.

MR. CAVEDO: So our conclusion is, as was demonstrated by that last slide, is that with these plant improvements in place our risk level post-EPU is actually going to be lower than our risk level pre-

EPU.

So that concludes this, unless there are any questions.

MEMBER SIEBER: Well, that conclusion is based on the fact that you're using surrogates as CDF and LERF as the measure of risk. The real risk also includes the magnitude of the source term?

MR. CAVEDO: Yes. To do a level three evaluation.

MEMBER SIEBER: Which is probably beyond the practice of PRA the way you all use it. On the other hand it's beyond 1.172 criteria. But I think overall you did a pretty decent job.

MR. CAVEDO: Well, one thing to consider with the source term is we are providing an extra risk benefit to the public by producing more power. And so the source term kind of offsets that. The reason we don't talk about the core damage is because if that went up, then of course that is proportional to the source term, which is more consequence.

MEMBER SIEBER: That's sort of relative, though. It depends on whether you're getting the increased power or you're getting the source term, you know. It may be two different sets.

CHAIRMAN DENNING: Go back one slide here.

MR. CAVEDO: Sure.

CHAIRMAN DENNING: Down on the bottom line here, I mean we had major fire contributors. As far as the benefit in reduced CDF and LERF, are they fairly evenly distributed among these areas of flooding, I mean proportional to what they were to the core damage frequency initially or is there some particular --

MR. CAVEDO: No. The fire and the shutdown took a bigger hit. And you can see that based on the previous chart.

CHAIRMAN DENNING: The fire is the one --

MR. CAVEDO: The fire in terms of human actions took a bigger hit.

CHAIRMAN DENNING: Yes.

MR. CAVEDO: But there's something that's interesting in the PRA is if you guarantee fail a bunch of equipment, then of course whether the operator could restore it or not is no longer relevant. So the fire if it fails a lot of equipment just due to the fire, then that's not going to show a big change. But for shutdown where it's a lot of operator action is required to recover from those, you can see that it was a 21 percent change in the core damage frequency because that's heavily reliant on operator actions and it's not so much driven by an outside or an event which damages multiple pieces of equipment at a time. It's just a loss of air, the operator fails to respond in time and then you have a negative consequence.

But this is how you can see what specifically was contributing to the risk.

CHAIRMAN DENNING: Okay. Any other comments, questions?

Good. Well, let's see what the Staff has to say about the risk.

MR. HARRISON: I'm Donnie Harrison. I'm magically moving the slides. Okay. We're done.

CHAIRMAN DENNING: Well, thank you.

MR. HARRISON: There you go.

I'm Donnie Harrison. And actually the Ginna analysis presentation makes my presentation a little simpler, because it's amazing two PRA analysts that actually ended up with similar slides.

But as part of this review I want to recognize that Otto Basioni was also a key member of the review team. So just as we go through this, it wasn't just one person that did the review; it was actually a couple.

I wanted to start off by just giving you the conclusion, which is the Staff believes that the licensee Ginna is adequately modeled and addressed the potential risk impacts due to the power uprate. And the subbullet there, it's from my observation this was the most complete submittal that I've seen to date trying to address the power uprate up front.

MEMBER SIEBER: I agree.

CHAIRMAN DENNING: Are you saying of the total thing or you mean the risk assessment or what?

MR. HARRISON: Yes. The risk assessment portion of the submittal was the most complete that I as an risk analyst has seen. So, yes, don't generalize that comment.

Being that it's nonrisk-informed, it still meets the risk acceptance guidelines of Reg. Guide 1.174.

And during our review we did not identify any special circumstances per the SRP 19 Appendix D criteria that we use.

And as you've heard a number of times so far, the licensee's used this analysis to actually identify potential improvements to the plant to make the plant actually safer.

CHAIRMAN DENNING: Incidentally, I think that that third bullet is the proper interpretation of

-- I think that, you know, these risk-informed changes and I think there are limitations to the 1.174 approach to power uprates. But your interpretation at least of the first third bullet, I certainly agree with.

MR. HARRISON: And as you said, this is the generic slide that we usually start with just to remind everyone that the power uprate submittals are not risk-informed. However, per the review standard, we get quite a bit of risk information in the submittal. And that information is used in two ways. One is just to determine that the risks are acceptable, and we use the Reg. Guide 1.174 guidelines as a judge on that. But also, we're looking to see if there's special circumstances. And for those not familiar with the process, special circumstances in this case is even though the licensee may meet all the regulatory requirements and may be able to show in the deterministic calculations that everything is acceptable and they meet all their acceptance criteria, if there's some issue that shows up that would make you question the safety of the plant, that's what we're looking for. Has this done something that even though it meets the regulations, it still creates an unsafe condition?

MEMBER WALLIS: Now this is completely independent of what we were talking about earlier, these various analyses of various events comparing results with criteria.

MR. HARRISON: Right.

MEMBER WALLIS: And if the number which we were just looking at which was very slightly below some acceptance criteria for those things have been above it, it wouldn't have shown up in the risk analysis at all. So it's a completely different world.

MR. HARRISON: It's a completely different world. That's a correct --

MEMBER WALLIS: That's always puzzled me a bit that you can sort of do all this LOCA analyses by different methods and it doesn't really show up in the risk analysis at all.

MR. HARRISON: Well, it shows up, but it's using different approaches --

MEMBER WALLIS: Different success criteria and so on?

MR. HARRISON: Different success criteria, that's right. And --

CHAIRMAN DENNING: It's because we don't consider the uncertainty of the success criteria.

That's the issue.

MEMBER WALLIS: Also it could be because the risk analysis uses very simplified thermal hydraulic models, too.

MR. HARRISON: It can be a balance of that. And you may have two PORVs requiring your design basis in the PRA analysis may say one PORV was good enough. So you can have those types of differences. So this is a different world from the deterministic world.

And the last bullet on this slide is just to make the observation that we've looked at a number of power uprates, both BWRs and PWRs ranging from 20 percent in the BWR world to 17 percent, if you will, for Ginna. And to date we have never identified anything that would be representative of a special circumstances.

MEMBER WALLIS: Now

MR. WOOD: and Ginna and Kewaunee and similar and they're going to the same power.

MR. HARRISON: Yes.

MEMBER WALLIS: What's the Kewaunee situation as regards to risk? Is it very comparable?

MR. HARRISON: Kewaunee's power uprate was done many years ago, if I remember.

MEMBER WALLIS: That was a smaller one?

MR. HARRISON: It was a smaller one because I think they started at a higher level. So it didn't take them as much to get up to the 17 --

MEMBER WALLIS: Because it's a very similar plant.

MR. HARRISON: Because I think this is something like 7 seven percent or 5 percent.

MR. DUNNE: Kewaunee was originally licensed to 1650. Basically they had the larger steam generators. This is the series 51 Westinghouse generator versus the series 44 generators that Ginna did. So Ginna was originally licensed at 1520. So when Kewaunee did their uprate, they went from the 1650 up to the 1772. And we did our uprate because we now have equivalence series 51 generators, it looked that we used the Kewaunee target as our potential target for doing an uprate. And we rounded it up to 1775.

MEMBER WALLIS: But their CDF values are very similar to yours?

MR. DUNNE: I don't know what -- yes, sir.

MR. FINLEY: Yes. I'm Mark Finley again.

The Kewaunee -- if you look a the Ginna risk profiles since I developed the original for

Ginna, a lot of the risk is driven by fire. And, you know, the non-LOCA, that type of thing. And Ginna also has five aux feedwater pumps, where Kewaunee will have three. And so a lot of the issues for the Ginna secondary site design is what drives the risk profile.

So the risk profile for Ginna are Kewaunee are going to be different. You know, the operator timing issues, that type of thing, there will be some similarities there. But, you know, if you look like where cable routing is from a fire concept, that's what drives the risk profile for Ginna. So the cable routing at Kewaunee is going to be different. So therefore, they'll have a different risk profile from a fire standpoint.

MR. HARRISON: I think it would be a fair observation, and we'll get to that in a minute, but for most power uprates the observation would be your main impact is going to be operator timing. So that would be a similarity between almost any power uprate that's come before you.

The next thing would be initiating event frequencies, you may postulate more trips due to reductions in operating margin.

You typically won't see much in component reliability because almost every licensee refurbishes their components or adjust their setpoints or they'll change the motors or and impellers and on their pumps so that they can handle the increased flow rates. So typically they'll make the argument that the component reliability should be comparable pre and post uprate because of that.

Sometimes you'll get an impact in success criteria, but those tend to be fairly minor at most plants.

This slide just identifies what Ginna covers. You have to recognize that Ginna actually has a PRA or PSA analysis for internal events, external events and shutdown operations. So they have a fairly full scope PRA. Most licensees don't have that.

On the level two side they used, at least for this application, the NUREG/CR 6595 simplified in containment of entry approach, which the Staff allows.

To give you the risk impacts, this is similar to what Rob presented before. The total CDF increases by 12 percent. The total LERF increases by 10 percent. Post power uprate give you the dominant impacts and what their percents were for CDF and LERF.

CHAIRMAN DENNING: Did you do SPAR analyses for internal events?

MR. HARRISON: In one case. We didn't do

a rerun of the SPAR model for Ginna, but we did do that for the situation with seismic events. We took the seismic initiator and put it into the SPAR model to see if we would get a comparable answer to what Ginna got. And we did. We got the same order of magnitude response to that.

CHAIRMAN DENNING: But as far as baseline?

MR. HARRISON: But we didn't do a baseline recalculation to compare --

CHAIRMAN DENNING: No. Recalculation.

MR. HARRISON: -- our numbers to their numbers.

CHAIRMAN DENNING: What about the baseline itself, the SPAR analysis must be reasonably consistent with the baseline?

MR. HARRISON: To be honest with you I don't know. I would have to go back and look. And it would surprise me if it weren't because they did a benchmarking exercise a while back to try to -- in the Reactor Oversight Program they go out to the sites and they benchmark their activities. And in doing that if they find there's a lot of differences, and it's typically the SPAR model that gets adjusted. So they'll adjust it to make them match. So I would be surprised if there was much, but to be honest with you, I can't tell you that, how close the numbers are.

CHAIRMAN DENNING: Are we looking at mean risks here? Are we looking at mean of a distribution that's calculated?

MR. HARRISON: I would represent these as point estimates.

CHAIRMAN DENNING: These are point estimates?

MR. HARRISON: Right. And when Rob was earlier talking about doing uncertainty analysis, I would really have characterized those as being sensitivity analysis.

CHAIRMAN DENNING: Sensitivity studies. Yes.

MR. HARRISON: Where they doubled the frequency or they did other things to try to get at what was important. It was really more sensitivity analysis than uncertainty analysis.

MEMBER WALLIS: Are these initiating events? I thought there were no changes in initiating event?

MR. HARRISON: No, there were in a couple of different areas. One is the initiating event dealing with the increased flow of main feedwater, main steam. They increased the failure probability for some pipe breaks. So you're going to have increased--

MEMBER WALLIS: Okay. As a result of increase or a result --

MR. HARRISON: -- now those segments of pipe have been put --

MEMBER WALLIS: ==of increase so there's more likelihood of a pipe break?

MR. HARRISON: Right. And they've put those into the corrosion/erosion program, but they went ahead and said with the increased flow there will be an increase probability of a pipe -- a segment of a pipe break.

There were some other things. There was the ATWS frequency goes up a little bit because all the initiators went up a little bit. If you had increased reactor trip, then you have an increase in the probability of an ATWS. And they increased the reactor trip frequency, so that gives you a connection there.

So, yes, there was about a 27 percent of the CDF increases due to initiating events, 63 percent of it is operator reaction timing, recovery timing driven. The numbers here are the same as what Rob provided in his presentation.

The one thing I want to emphasize here is

Ginna has used this risk evaluation as an opportunity to identify potential changes to make the plant safer that could reduce risk. Now in their submittal they identified what they refer to as risk and cost beneficial changes. They didn't conclude it by talking about the three that they've talked about implementing. But there were a total of five that were originally identified. So don't get too confused between five and three.

MR. CAVEDO: This is Rob Cavedo again.

MR. CAVEDO: We actually are going to do all of those. The only reason that I mentioned the three in the slide is because they provide the largest risk benefit.

MR. HARRISON: And this just gives you a bulletized list of what the five are. Rob's already mentioned three of them. The last two here I think are the ones that weren't mentioned before, which are local controls for the turbine driven aux feedwater pump discharge motor-operated valve and relocating the charging pump control power disconnect.

Okay. And we're back to my conclusion. I've got one more slide after this, though.

Again, just to reiterate. The Staff believes that the licensee's model, the power uprate correctly using the tools. The risks are acceptable. If this were risk-informed submittal, it would still be acceptable even without the mods that the licensee is making to reduce risk.

No special circumstances have been created.

And they've used this to identify those five mods that would even further improve risk and make the plant actually from a risk perspective lower than where it is today.

And just as a going forward strategy, the Staff sees a need that licensee will continue to need to provide risk information as part of their submittals under the Review Standard 001. However, to better utilize Staff resources, within the Review Standard there's an option that says if we look at what the licensee submits and it looks complete and has addressed all the issues that we can, if you will, truncate our review and we can submit a letter to the project manager and say we've reviewed it, it's complete, you know you can use that information as the Staff input. So it would be a way to truncate our review.

We haven't done that to date But going forward as we may actually start to implement that part of the review standard that would let us shorten our review, as long as the licensee provides all the information and it looks complete. So then that would focus our review on just making sure the information is complete and addresses special circumstances and risk acceptability.

And just the last bullet. I just want to take this as an opportunity to commend Ginna for actually using the risk evaluation to identify those plant changes that they've called for. It's really easy for a licensee to say we meet Reg. Guide 1.174, we're good enough, let's go. And to see actually a licensee say hey, but we can learn something here and use it, that's worth commending them for. And I would hope that that would be a lesson that they would share with the rest of the industry and that the industry would take that, if you will, as a challenge to say when you do these evaluations, use them and come back and see what you can do to improve your plant.

With that note --

MEMBER SIEBER: I for one certainly agree with your last bullet. I think this whole piece of this is very well done.

CHAIRMAN DENNING: I certainly agree. Thank you very much.

MR. HARRISON: Okay.

CHAIRMAN DENNING: All right. Now this is where electrical is going to be interjected, is that a true statement?

MR. FINLEY: Yes, it is. Yes.

I'd like to introduce Joe Pacher, the System Engineering Director from Ginna.

MR. PACHER: Hi. I've been at Ginna for about 20 years. I'm SOR certified there. I've been in engineering in a couple different supervisory positions. And before that I did many electrical analysis on the distribution side of the plant.

What I'm going to talk about today is our evaluations and some of the modifications we're doing on the power delivery side, and then some of the evaluations we did on our impact on the grid for the power uprate.

On the electrical power delivery side, we did do extensive verification and review of onsite and offsite transmission electrical equipment. We did identify, and I'll talk about four specific modifications on the power delivery side that we identified early on our feasibility study that needed some upgrades. And fortunately by identifying them early, it gave us plenty of opportunities to look at industry and to actually do some of the modifications in our 2005 outage and some additional inspections on them. We've been monitoring the performance of that equipment since that time to verify we're going to both maintain adequate margin after uprate and we're going to have reliability after uprate on this equipment.

MEMBER WALLIS: Do you ever assess the possibility of switchyard fires? Some plants have had fires int he switchyard. Is this part of your assessment here?

MR. PACHER: It's not part of what I'm presenting?

MEMBER WALLIS: You're not?

MR. PACHER: None of the changes we're doing should impact the likelihood of a fire in our switchyard. The only thing I can think of would be the transformer.

MEMBER WALLIS: Right. The transformers.

MR. PACHER: Yes. And the transformer, that's the first thing I'm going to talk about. What we have right now it's a three phase 19kV to 115kV transformer. It was installed in 1996, so it's not a significantly old transformer. We installed it in '96 based on some gassing increasing we saw in our previous transformer. That transformer has four cooling banks. And like Mark mentioned on, it gave us one cooling bank as a spare. For our uprate we've installed a fifth cooling bank so that we can maintain the same margin. We're not going to see increases in operating temperatures above what we saw before. So our overall risk of a transformer fire shouldn't have increased.

So the two things we had to do on that transformer was install the fifth bank and replace the high side voltage bushings. And we did those replacements in 2005.

I n addition to doing those replacements, it gave us an opportunity since we had to have the transformer drained to do some detailed inspections, some testing. We had GE come in, spend some time going through the transformer. Replaced all our coolers, replaced all our pumps, replaced the bladder. We did some other inspections. So we got some very high confidence that transformer is going to be reliable after.

Based on our OE searches, one of the things we noticed plants were seeing after uprates was they were seeing higher temperatures than expected on the transformer based on local ambient temperatures.

We did monitoring last summer and verified that the assumptions that went into our seizing of the fifth cooler in the rating of the transformer were valid based on the temperatures in that area, and we'll continue to monitor it this summer.

MEMBER WALLIS: Now what's the interaction between you and the grid? I mean you're producing more power and presumably there has to be some assessment from beyond your plant, which isn't directly your responsibility.

MR. PACHER: Yes.

MEMBER WALLIS: But you haven't changed the probability of some transient on the grid which would cause you a loss of offsite power.

MR. PACHER: Yes.

MEMBER WALLIS: There's proper interaction with whatever is responsible for that?

MR. PACHER: Yes, there is some interaction. Unfortunately, it's coming up in a couple of slides here, but I'll go into that.

MEMBER WALLIS: You were going to go into that?

MR. PACHER: The time that we did the feasibility study was the same time Ginna's ownership was being sold to Constellation. So at that point there was a lot of interactions because we were discussing uprate at the time with our local transmission operator, which is Entergy East, to do some detailed evaluations of the impact of our uprate on grid reliability on equipment ratings.

Where we're positioned in the transmission system the actual 80 megawatt increase really didn't impact the overall grid reliability. The bar capability of the generator has more impact than the megawatt increase.

So they helped us perform those detailed studies. Everything was proven to be acceptable. But there is another study going on right now as part of the New York ISO for the class of 2006 where they look at not just our uprate, but all power increases on the grid in New York. And they're doing various stability studies throughout the system. And at this point they've identified nothing that Ginna would impact that over our good reliability.

The second matter I wanted to talk about was the main generator. It's a 19kV generator. When we looked at that generator it was originally rated for 616 MBA to .85 power factor for uprate. We're taking it to 667 MBA. We did some benchmark and we worked with Siemens Westinghouse.

That same frame generator is installed at many other places -- not many. Some other places with a 667 MBA rating. The delta for us was our condensate cooler. And we are going to replace our condensate cooler. But our overall windings and design is adequate for the 667 MBA rating.

Now knowing that we were going to do this uprate last outage, we did do a major inspection our generator. Our generator has been performing exceptionally. Again, we didn't find any indications that would indicate that we wouldn't have a reliable generator after. But we did do three modifications last outage, including a flux probe, a partial discharge monitor and an intern vibration monitor that we've been monitoring since that during startup and since the outage to verify that the generator is indeed performing reliable.

Now those monitors were picked based on some OE searches we did on what failure foods for this type of generator. And we feel that monitoring is going to assure us that we're going to have good reliability on that generator after uprate.

MEMBER SIEBER: Does that have a static exciter on it or a rotating exciter?

MR. PACHER: It's a rotating exciter. And that exciter we did --

MEMBER SIEBER: Old fashioned?

MR. PACHER: It's an old fashioned one. Very reliable old fashioned one, but --

MEMBER SIEBER: Yes, right. It's more work for the operator.

MR. PACHER: Right.

MEMBER SIEBER: Changing brushes.

MR. PACHER: The third modification we had to do was on our iso-phase bus duct cooler. What we have is a 19kV bus duct. It's service water cooled. Right now there's two fans and both fans operate all the time. There's been significant OE in the industry of plants that have done uprates, Clinton, Vermont Yankee where they've done the uprates and they've increased their fan flow substantially and they experienced delamination of the flexible links that resulted in shorts and plant trips and fires, actually. We looked at their evaluations extensively.

For our uprate we have a different type of flex link design, so that failure mode we're not as susceptible to. Last outage we did some detailed inspections of our iso-phase. We had Delta Unibus work with us. We didn't find any issues with our iso-phase, but we did put a focus on out of this uprate we didn't want to increase our cooling flow, our air flow too much that we were going to get into any of these vibration issues. And actually our changes really -- if we're going to run the two existing fans that we have right now, we're going to see about a four percent increase in flow. And if we run the third fan we're putting in, we'll see about a ten percent in flow. So our increases in flow are substantially lower than the other plants, both Clinton and Vermont Yankee, who experienced problems.

Like I say, we are putting a third cooling fan in. That gives us some operational margin if we do have a trip or a failure of one of the existing fans. It will be a manual action for operations to start that fan. But we won't have to derate for a failure of one fan.

The other things we did is the two existing fans that we have, the motors are marginally sized at this point. Sometimes during startups we have some issues with those motors. We are increasing the size of those motors to give us more margin in those motors.

I can say throughout the uprate projects there's been many other motors in the plant that we've increased the rate. We've replaced the motors out with a higher horsepower motors to give us some margin. In cases we really didn't need that margin technically, but it gives us some operating margin going forward. Especially given the vintage of our plant, it's a good time to put the newer motors in for reliability out to 60 years.

MEMBER SIEBER: Do you maintain sufficient margin in interrupt capacity of switchyard circuit breakers and the main unit breakers?

MR. PACHER: Yes.

MEMBER SIEBER: You checked that, right?

MR. PACHER: Yes. We did low flow studies and short circuit analysis.

MEMBER SIEBER: Okay.

MR. PACHER: Since we're not replacing our generator, we didn't replace the transformer, our actual fault circuits in our switchyard --

MEMBER SIEBER: Stays the same?

MR. PACHER: -- really haven't changed. And we have adequate margin there.

MEMBER SIEBER: Okay.

MR. PACHER: The other thing we did on the iso-phase is we are installing some additional indications. We're putting the air temperature on the plant computer so operations has that visible. There will be alarms so they can have some improved monitoring after uprate that they presently do not have.

The fourth component we're doing some modifications on is our oil static pipe cable system. We're a little unique in this application. Instead of having overhead transmission lines going from our onsite substation to our substation across the street from this plant, it's an underground oil pipe filled system. It's 4, 8 and a quarter inch pipes with 2000 KM cables in there that are -- it's oil pressurized between 180 and 220 pounds. And it's been a very reliable system. It's a static pressurization system right now. No recirculation.

When they built the plant they did put recirc pumps in so that they could do recirc flow. But based on the operating temperatures and what the plant was originally sized to, we did not have to put recirc flow. We didn't have to put in service.

For uprate we did some detailed reviews of this. Like I said, there's not a lot of nuclear OE experience, so we brought in Underground Systems, Incorporated. They're a company that does a lot of oil pipe systems in non-nuclear applications. They came in, did a complete checkout of our system, did some oil samples. We dug down to the pipe. We examined the coatings. We did some testing to verify the pipe coatings were adequate. And they gave us a clean bill of health on our system. But the temperature studies we've done has indicated that in the peak summer time it will beneficial to go to recirculation mode to keep the temperatures down in the oil. Basically it's a 2900 foot pipe, four sets of pipe that go in some shady areas, go in some grassy areas and also go into a parking lot.

The parking lot was a particular concern backaches that would be the hottest spot. In that location we did dig down and we put thermal couples on the oil pipe cables under that parking lot. And we're going to tie that to our plant monitor so we can monitor it going forward. And our plan right now based on our studies is that we're going to have to operate that system in recirc for three to four months during the summer time frame.

Now we did it operate it last year for a portion of the year to get some operating experience on it. We are going to run it again this summer to make sure that work out any bugs, we can verify it's going to be a reliable system so after uprate we should have a fairly reliable design.

MEMBER SIEBER: Now that system, does that work like a transformer oil when you get deterioration and some arcing inside, you form a setaline gas --

MR. PACHER: Yes. Yes. And they sampled it this year. IEEE 1406 had some criteria in there that you could give an indication of how much aging you've done on the oil looking at $C0_2$ levels.

MEMBER SIEBER: Right.

MR. PACHER: Basically our levels were consistent with an application of less than five years of service. So it was obviously an indication that we've operated this well below its ratings historically.

MEMBER SIEBER: Now do you have a procedure in the plant where you sample the oil in this duct system the way you sample oil in the transformer --

MR. PACHER: We have not --

MEMBER SIEBER: -- to look at it for indicators of incipient failure?

MR. PACHER: No. On the transformers we do have online monitors. On the oil pipe system, since it was a static system, samples in the past wouldn't have really given us much because it could have been-- you know it depends where the partial discharge was occurring if it was occurring in the middle of the pipe.

Once we start operating in recirculation mode, that's one of the PM changes we're looking at is what type of frequency we should take samples of that oil and get --

MEMBER SIEBER: Well, this line is not safety related, right?

MR. PACHER: Right. Right. But from a reliability point it's pretty important.

MEMBER SIEBER: Well, even if it trips it doesn't change your lube frequency or anything like that, right?

MR. PACHER: No.

MEMBER SIEBER: And so it's just be a business decision as to the extent to which you wanted to monitor.

MR. PACHER: Right. And obviously anything here I consider pretty critical from a reliability, and I'm sure my bosses think it's pretty critical if something happened to that line after -- we are --

MEMBER SIEBER: That's up to you folks.

MR. PACHER: Yes. I mean, we have gone through all the equipment out in that pump house, both the pressurization system and the recirc system. And like I say, we are going to run it this summer even though we don't need to just to verify reliability.

MEMBER SIEBER: Does this go through the apple orchard?

MR. PACHER: Yes. Yes. It goes underneath the apple orchard.

MEMBER SIEBER: Well don't mess up the apple orchard.

MR. PACHER: It's actually a good spot because it's shady there. So it's a good area.

As far as the electrical impacts on the grid, I did mention that already. The main generator, we're bound by our interconnect agreement with Entergy East to be able to verify a 100 megabars both leading and lagging. After uprate we will be able to meet that, we will be able to provide 260 megabars out and we'll be able to take a 100 megabars in. So we can meet the requirements. It'd be highly unlikely we'd ever be at the 260 megabars out, but we have the capability in all our components in the power delivery path are now rated to handle that.

Like I said, the New York is always working with us doing the class of 2006, they call it, where they're looking at all the generating stations. And the grid can withstand a trip of Ginna during worse case conditions.

MEMBER MAYNARD: A quick question on that. Is that true even if you have one -- I don't know how many offsite lines you have coming in, but some plants their line or two of the offsite line is not available, then they have to reduce power because it can't take a trip. Does that apply to Ginna at all?

MR. PACHER: We have -- our substation across the street is a 115 kV system, but it does have five separate transmission lines that come into it. Right now we don't have to derate if anyone of those lines go out. There is some contingencies where two lines are on a single pole where we can get into scenarios if lines out, where they might ask us to derate. But at the present time we don't have to derate if any single goes out.

MEMBER MAYNARD: Okay. Does the extended power uprate effect that or not? You have the same situation or without the power uprate?

MR. PACHER: That's one of the studies we're finalizing right now.

MEMBER MAYNARD: Okay.

MR. PACHER: But right now the indications are it is going to be -- we won't have to derate after -- with a single line being out. Now there is some upgrades going onto this system planned outside of uprate where they're bring a sixth line in and it's going to even make it more stable. But right now there's no plans to have to derate for a single line being out, pre-uprate or post-uprate.

MEMBER MAYNARD: Okay.

MR. PACHER: Some other things we're doing that are not uprate related but the timing is work at least noting is we have two offsite circuits coming to the plant, one is an underground fed circuit, Circuit 767 has been highly reliable over time. The other one is Circuit 751, which is an overhead transmission line.

The overhead line, obviously, is exposed to the elements. We've had failures of that. It's been a concern with us on reliability. We have a modification going on right now that will be scheduled to be done by September to bury that line and feed it underground, too, so that we can get the same reliability on that offsite circuit as we have on 767.

The other thing we're doing is right now the control room has curves in the control room to verify voltages in our bar generation to make sure that our post trip voltages are adequate. We are working with our local transmission operator and we have a contract in place with him right now for this summer to have an online contingency monitor. And we're working with him on the protocol on how we communicate those issues. If there's something going on in the transmission system where our post trip contingency voltage is below our limits, our operation shift would be immediately notified.

So those are two activities. They're not uprate related, but they are things that we're doing that should improve the reliability of our offsite power and our transmission system post-uprate.

The last bullet here was our four hour station blackout coping capability. The uprate didn't really add any significant DC loads, negligible real increase on the DC system. So we haven't impacted our four hour coping capability of our batteries.

I do make a note here that last time the batteries came up for PM replacement, when we replaced them we put in bigger batteries. We went from 1200 amp hour to 1495 amp hour batteries to give us some additional margin, and obviously that margin is still there. And it's not being impacted by uprate.

MEMBER SIEBER: When did the battery replacement occur?

MR. PACHER: I think it was 2000. I think it was 2000.

MEMBER SIEBER: So these are pretty new batteries.

MR. PACHER: Yes, these are pretty new batteries.

MEMBER SIEBER: Okay.

MEMBER WALLIS: This is the second time we've replaced them. Last time we did 1050s and when we replaced them we went to 1200. So it was a case where we had to do a replacement we wanted to get some margin and we took advantage of it.

MEMBER SIEBER: Okay. That's good.

MR. PACHER: That's all I have. I introduce Jim Dunne for mechanical impacts.

Thank you.

MEMBER SIEBER: Thanks.

MR. DUNNE: Good afternoon. I'm Jim Dunne. I'm an engineering consultant in the design engineering group at Ginna. I've been in the engineering department at Ginna for approximately 15 years. And for the last approximately three years I've been the lead mechanical engineer on the uprate project.

Today I want to talk about how the uprate project has effected a number of different mechanical systems and components. Specifically to talk about the impact of upgrade on steam generator vibration, which will also including some discussion on a steam separator designer, even though we don't really have any vibration analysis of our steam generators. But because of the BWR experience, which is why is expect that you would be interested in our separator design.

Also review the impact of uprate on the major BOP heat exchanger and the process systems. And the vibration monitoring program that we will be implementing to support uprate from a piping component point of view.

Also quickly go over the effect of uprate on the flow accelerated corrosion program we presently have in place.

And finally talk about how uprate has effected a number of our existing cooling system, decay heat removal and some others.

MEMBER SIEBER: A quick question. When you bought your replacement steam generators, did you specify that you would be operating at this higher steam flow?No

MR. DUNNE: No, we didn't.

MEMBER SIEBER: So is a reanalysis required --

MR. DUNNE: That's correct. And that's--

MEMBER SIEBER: -- to qualify the steam separators?

MR. DUNNE: That is correct. That gets into my next slide specifically on steam generator vibration. As we stated earlier, our original generators were Westinghouse series 44 generators. And in 1966 we replaced them with new generators manufactured by B&W Canada. Same feed rate in design. The major changes to the generators where we increased the surface area from 44,000 to 54,000 square feet, we changed out the tube material from alloy 600 to 690. And from a steam separator point of view we changed the design moisture carry over number from 0.25 percent down to 0.1 percent.

As part of the --

MEMBER SIEBER: And that's at the old plant rate?

MR. DUNNE: Right.

MEMBER SIEBER: Okay.

MR. DUNNE: So as part of the original uprate or original replacement, B&W Canada was tasked with doing a vibration analysis of the two bundle design where they looked at a number of different areas. For the uprate we have gone back to B&W Canada and asked them to basically revise their original design to take into account the uprated conditions. And for that analysis we gave them conservative bounding estimates to use for their analysis.

For example, we expect our steam generator, all that pressure based upon our HP turbine design, to be around 800 psia. And for the uprate, for the reassessment of the bundle we asked B&W Canada to conservatively assume a 750 psia outlet pressure. The lower pressure the maximize the velocity in the two bundle so that we had margin in our analysis.

With regard to the original analysis, which is the same as what they have redone, they basically used the ATHOS computer program to calculate the three dimensional flow through the bundle and it's a two phase flow model. They used the ATHOS program to identify areas in the two bundle design that had velocities and also to get the velocity profile density and quality profile within the bundle. Then that --

MEMBER WALLIS: Can I ask you these steam generators. Are there other plants using the --

MR. DUNNE: Yes.

MEMBER WALLIS: -- same steam generator --

MR. DUNNE: Yes, there are.

MEMBER WALLIS: -- under the essentially the same velocity conditions and so on?

MR. DUNNE: Well, there are other plants that have B&W replacement generators. Basically the general design we have is the same design that they've been using for the CANDU steam generators. And there have been a number of U.S. utilities who have bought replacement generators from B&W --

MEMBER WALLIS: Well, whatever these analyses show, if you can actually show there's an experience pace which says that these steam generators are not prone to vibration under these conditions, that is also useful information.

MR. DUNNE: Correct. And for example there are I believe around 70 to 80 steam generators operating in the world, about 35 or 40 of them in the U.S. including ours that have been operating for periods of time. We've been operating our generators for ten years. And we have not seen any indications of vibration damage or wear in our steam generator bundle consistent with the original analysis. And from my understanding, that's basically true throughout the B&W Canada replacement generator fleet.

The types of vibration analyses they did were basically in the area of the two bundle that are exposed to cross flow, which is basically the two entrance region and the U-bend region of the bundles.

The types of vibration analyses they did is basically they do a fluidelastic instability calculations both the tube entrance and the U-bend region. They do a vortex shedding analysis only for the tube entrance region because it's an inlet effect and that's really the only place where you have flow entering the bundle. They do a random turbulence excitation analysis for displacements for both the U-Bend and the tube entrance region. And they also do a tube wear analysis for the U-bend. Their experience has been that if you're going to see any tube wear due with wear with supports, it's in the U-bend and not anywhere else in the bundle.

So basically they have repeated that set of analyses for Ginna for the uprate conditions. As you would expect with the increased flow we're getting, in general the numbers increase slightly over what we had previously. But for all of the parameters that were investigated, we still met the B&W acceptance criteria.

For example, for fluidelastic instability the limiting tube velocity ratio that we have at uprate is .87 with a criteria of less than 1.0. And that compares to, I believe, for the present design a value of around .81 for the same tube location. So you see an increase but we're still below the acceptance criteria.

For vortex shedding they use a criteria that the tube displacement for vortex shedding should nominally not be greater than 2 percent of the tube OD. The original analysis we had cut one tube where we were slightly over 2 percent, that they determined was acceptable because of the conservatism in the methodology. At uprate that tube, the displacement has increased slightly but it's gone from like 2.05 percent up to like 2.15 percent, a minor change. And it was viewed as still being acceptable.

Random turbulence excitation, they use a criteria of 15 mils displacements -- excuse me, 10 mils displacement. And none of our tubes either for the present design condition or with the uprate are anywhere near the 10 mil number they use.

The tube wear analysis for the U-bend is a little bit different for uprate than was done for the original design. The original design back in 1994 and '95 when the generators were being designed by B&@ Canada they used a qualitative assessment on tube wear in the U-bend region comparing the Kewaunee thermal dynamic conditions and geometric parameters to other replacement generators or steam generator designs that they had built and they put in service and ranked us compared to other units to basically show that we were bounded by existing units.

Since then they've come up with a quantitative method for assessing tube wear in the U-bend. And for our uprate reanalysis, they basically did the quantitative method that they're using presently. Basically their criteria is over a 40 year life of a steam generator that the tube wear due to fretting between tubes and the tube support plates in the U-bend region should not exceed 40 percent throughwall. Their analysis for us at the uprated conditions it showed that none of the wear over a 40 year life would exceed 20 percent. So we're well within their acceptance criteria.

MEMBER SIEBER: Do you just drilled support plates?

MR. DUNNE: No, we don't. We have a basically a lattice grid design.

MEMBER SIEBER: Okay.

MR. DUNNE: It's completely different--

MEMBER SIEBER: Like a combustion engineering --

MR. DUNNE: So it's a line interface, if you will, versus you know a full tube interface or a drilled hole interface.

MEMBER SIEBER: Okay.

MR. DUNNE: So the conclusion of the assessment was that the present design is adequate for the uprated conditions and that there were no other actions that we need to take. We will continue to do our normal monitoring of the tubes per our existing schedule to, again, verify we see no wear or corrosion related indications with the bundle.

MEMBER SIEBER: Now you did not discuss the steam separator at the top.

MR. DUNNE: Next slide.

MEMBER SIEBER: Oh, okay. Well, let me ask a question.

MR. DUNNE: Sure.

MEMBER SIEBER: And then you can work it into your discussion. In ten years I'm sure you've done the inspections --

MR. DUNNE: Yes, we have. We do inspections.

MEMBER SIEBER: What did you find.

MR. DUNNE: Excuse me?

MEMBER SIEBER: What did you find?

MR. DUNNE: We didn't find a heck of a lot. We found magnetite buildup on surfaces, but we haven't seen any other indications of wear or any broken welds or anything along those lines.

Basically the Ginna steam generators originally with the Westinghouse series 44 generators are primary separators with a swirl vane separators, three big swirl vanes.

MEMBER SIEBER: Right.

MR. DUNNE: And then our secondary separators were basically a Chevron de-mister type hood, a secondary separator.

The B&W design for a primary and secondary separators is completely different than that. They basically use a centrifugal separation for both the primary and the secondary separators.

The replacement generators have 85 primary to secondary separator modules installed in the steam dome region.

MEMBER SIEBER: Yes.

MR. DUNNE: To basically equalize the steam flow over the entire bundle. Also the one feature of that is that it allowed them to do full scale testing of their primary and secondary separator designs at actual operating conditions and steam flow so you didn't have to do any extrapolation from scale testing to figure out the performance of the separators.

MEMBER SIEBER: Okay.

MR. DUNNE: Based upon the design there's minimum cross flow for the components in the steam dome region. And the way it's constructed, it's a relatively rigid structure which we believe is not susceptible to bundle design.

I'll have some slides after I get through these bullets to show a little bit more of the details of the design.

And again, as I stated, they have done full scale model testing of these modules for operating pressures between 750 up to, I believe 950 psia, for steam flows up to 5800 pounds per hour per module.

Presently at our present operating condition our average steam flow is on the order of 38,500 pounds per hour. At uprate we'll be increasing our steam flow to around 45,000 pounds per hour per m module. So we're well within the range of steam flows that they have tested these modules at a laboratory.

MEMBER SIEBER: And what separation have

you gotten so far? .25?

MR. DUNNE: When we replaced the generators in 1996 we did a sodium 24 tracer test, basically it was a performance warranty test to prove that they met the 0.1 percent design requirement for the new separators versus the 2.5 percent we have the old. The results of that separator test we're getting moisture carryover rates on the order of .015 to .02 percent.

MEMBER SIEBER: Okay.

MR. DUNNE: So about a factor of five less than the design.

Now at uprate we expect actual moisture carryover will increase. Their full scale model testing basically shows that as you increase the steam flow, you tend to get higher qualities. However, you don't really get beyond the 0.1 percent design until you start approaching that 58,000 per hour number per module. So in general we expect that at uprate we will still be well below our design requirement for moisture carryover of .1 percent. We'll probably be down around the .04 to .04 percent range based upon the laboratory test results they have.

MEMBER SIEBER: Okay. What's the steam quality of the turbine exhaust?

MR. DUNNE: The HP turbine exhaust?

MEMBER SIEBER: No. The LP turbine.

MR. DUNNE: The LP?

MEMBER SIEBER: Yes, that's where you get the wear.

MR. DUNNE: Yes. I'm guessing off the top of my head it's around 18 percent. We actually may have higher quality at the HP exhaust. Higher quality, yes, less moisture at the HP turbine exhaust at uprate than we do at the present power level because we're going to have a higher back pressure in our condenser.

MEMBER SIEBER: I would think so. I would think so.

MR. DUNNE: I don't believe the quality has really changed that much. We're basically coming out at a higher back pressure, but the quality is about the same.

MEMBER SIEBER: Okay. Okay.

MR. DUNNE: Okay. So just to show you what our steam separators look like, this is an elevation view of the steam drum region of our steam separators. And basically the long riser tube that you see is our primary separator. There is a curved arm separator up at the top. And then you'll see there's a gap and then another set of modules, squat modules all the way up at the top just below the secondary plate. Those squat modules are our secondary separators.

In reality even though this drawing doesn't show it, the entire cross section is filled with the separators. So if you go in and look down at the primary separators, what you end up seeing is something that looks like that. Basically what dictates the number of steam separator modules that we install in the steam drum --

MEMBER SIEBER: How big it is.

MR. DUNNE: -- is how big the steam drum is and how many of these things we can put in. Basically the size of these modules from a diameter point of view is the same for all the uprate plants. And what changes the number of modules from one steam generator versus another steam generator is the diameter of the steam drum.

So if you just go in now and look at one individual separator, this is what you see. You see a riser plate at the bottom that is welded to the primary deck. So the steam flow leaving the U-bend is coming out of that riser plate, going up to that curved armed vane separator where you do your initial separation of steam and water. The steam comes up and proceeds upward. The water basically gets spinned out of the curved armed separator, hits the return canister and then drains down the return canister.

MEMBER WALLIS: So the purpose of that long riser is what?

MR. DUNNE: Well, one of the purposes is to get the primary separator up above the water level in the steam generator.

MEMBER SIEBER: Yes.

MR. DUNNE: I think that's basically the prime purpose for it. Because the normal water level in the generator may be 4 or 5 feet above the primary deck. And you also want to have it above it so that on operational transients you don't flood out the separator, the primary separator. And basically the testing that was done on these modules basically showed the moisture removal characteristics of the primary separators pretty independent of water level as long as the water doesn't rise into the primary separator themselves.

So the return canister is basically welded to the riser tube at the bottom by two plates 180 degrees apart. And then the two sets of alignment bolts, one at the bottom and one up near the top that they used to center the riser plate inside the return canister.

Now what they end up doing is the primary deck has a stiffener plate welded to the top of it that go across the length of the primary deck to stiffen it up. It's one inch thick steel.

The separators have separator ties welded to the outside of them where they basically end up welding adjacent separators to these ties to try and make the entire bundle more rigid. So one separator if it tries to move laterally is transmitting its load to the seven separators.

Basically the ties are basically small bore piping, schedule 40 piping. Anywhere from, I believe, maybe one inch up to inch depending upon the location in the tube bundle.

The secondary separators, again, it's a curved arm separator where you get steam coming in introducing a swirl to separate the water from the steam. And the steam passes up and then there's a drain tube in the bottom of the box that collects the water and drains it back to the == basically, the water side of the generator.

The curved arm separators are welded to the separator plate that's above it. The separator plate is basically half inch carbon steel plate and it's got stiffeners underneath it running from one end to the other laterally. And in between those there are spacers that go from one separator to another to make it a very rigid structure.

MEMBER SIEBER: It seems like it would be hard to inspect.

MR. DUNNE: Actually, let me go back --

MEMBER SIEBER: Do you use a baroscope or something?

MR. DUNNE: What you end up doing, there's a manway at the top --

MEMBER SIEBER: Right.

MR. DUNNE: -- of the steam generator. We can enter that manway and basically get into that steam dome region.

MEMBER SIEBER: Right.

MR. DUNNE: And that allows us to inspect the secondary deck plate and we can also inspect all t hose secondary separators because we can look down into that.

MEMBER SIEBER: Right.

MR. DUNNE: There is always, and you don't see it here, but down in the bottom there's a boxed area over by the feed ring, that's basically a ladder access that allows us to climb down through the separator bundle. It's primarily there to allow us to access the U-bend region of the steam generator. But we can also as we go down there look in at those modules.

MEMBER SIEBER: With all those welds in there, it doesn't look like you could go and inspect them.

MR. DUNNE: No. No. We really can't go in and inspect the welds on those separator ties, for example.

MEMBER SIEBER: Right.

MR. DUNNE: So if you go in and compare what we have to what we understand the BWR steam generators look like, and this is sort of similar to the criterion that I think Waterford used to the full ACRS. As a matter of fact, that's where we stole their BWR cartoon. But the design and the flow patterns basically are completely different.

We believe we have a rigid structure to begin with. And basically whereas they had flow patterns that were inducing a lot of turbulence in the reactor vessel head trying to work its way over to the main steam nozzle, we basically have a uniform flow path going to our main steam nozzle so we don't believe we're going to get turbulence within the bundle that would cause any flow induced vibration on our steam separating system.

MEMBER SIEBER: There is an advantage of having the steam outlet at the top as opposed to the side where you have to --

MR. DUNNE: That's where the steam wants to go.

MEMBER SIEBER: Yes. Correct.

MR. DUNNE: So that's basically what I have on the steam separators for Ginna.

CHAIRMAN DENNING: Do you have vibration monitors downstream that could pick up a vibration if one were to occur.

MR. DUNNE: No. We don't have vibration monitors installed on our main steam piping. As part of vibration piping monitoring program we may be installing some monitors for the power escalation on the main steam line to monitor data. But in general we don't monitor vibration on it.

Now one thing we do have if we had a loose part and it fell down into the bundle, we do have an acoustic monitoring system on the tube sheet region of our steam generators which basically would alarm in the control room if it got any acoustic signals that were outside its normal range. It's primarily intended to tell us that we've got a loose part basically in the bottom of the bundle design that may be causing a wear indication.

MEMBER MAYNARD: And I would think that if you had vibration especially if it was causing any contact between any points, that monitoring system would pick that up.

MR. DUNNE: Depending upon -- possibly. I don't want to say conclusively that if we had any vibration it would pick it up. I think if we had any major issues due to the parts that fell off that were rattling around in the U-bend or in the steam generator, we would hope that that acoustic monitoring system would notice a change and alarm and force us to go figure out why it alarmed on us.

MEMBER SIEBER: I noticed in one of the pictures, and this isn't a safety issue either, that from the feed drain you don't have the old Westinghouse design --

MR. DUNNE: No. We have a gooseneck design so that instead of the feedwater nozzle --and so the feedwater coming horizontally into the feed ring and then feeding out, and the original design had the holes in the bottom which caused steam generator water hammer problems and then we went to J-nozzles. We have J-nozzles on our feed ring, but instead of coming directly into the feed ring, we come in and we have a gooseneck piping that goes up and comes down.

MEMBER SIEBER: Like a trap?

MR. DUNNE: To trap it and minimize, basically, draining the header and causing a steam generator water head issue.

MEMBER SIEBER: Yes. I thought I saw that on the drawing.

MR. DUNNE: That was one of the features associated with the new replacement generators over the old design.

MEMBER SIEBER: Yes.

MEMBER WALLIS: Is a gooseneck the same as a J-tube?

MR. DUNNE: Possibly.

MEMBER WALLIS: Isn't it really the same thing?

MR. DUNNE: I always called it a gooseneck, but it's basically a U-bend basically type deal.

So if there aren't any other questions, I will move on -- if I can figure out where I am. Okay.

Balance of plant heat exchanges.

Basically, obviously increasing flows around the process piping and the main feedwater, main steam extraction steams we're increasing mass flow rates to our feedwater heaters.

Ginna has two trains of feedwater heaters, each train has five feedwater heaters, four low pressure heaters and one high pressure heater. Three of our four low pressure heaters basically have a drain cooling section, one of them doesn't it's just a condensing heater design.

So as part of the uprate and based upon the operating experience out there from past uprates where people have had vibration problems after uprate with their heat exchanges, we basically contracted with TEI, Thermal Engineering International which is the old Southwest Engineering, to go back and do an assessment of our existing feedwater heaters at the uprated condition. Basically Ginna has changed out all of the tube bundles in our existing feedwater heaters. We originally had cooper alloy tubing and as part of steam generator corrosion from the early '80s up to 1995 we're in the processing of retubing our heat exchangers.

TEI or Southwest Engineering was responsible for providing three of the five new tube bundles, so they were very familiar with that design because it was theirs. And the other two were Marley, who I guess had gone out of business, but they had access to their design information.

So we asked them to review the feedwater heaters for uprate from both a vibration point of view, velocity point of view, thermal performance point of view.

From a vibration point of view basically their conclusion was that there is no concerns with vibration in the condensing zone region of the feedwater heaters. They were more concerned about the potential for vibration in the drain cooling section, so they did detailed calculations for fluid elastic instability in the drain cooling section. Their conclusions were that on all four of the feedwater heaters that have drain cooling sections that the velocity was below the critical velocity.

They had one concern because their normal design practice for a new feedwater heater is to design it to a velocity ratio of 0.75. And we had one set of heaters, our number 5 feedwater heaters which are our high pressure heaters, where our velocity ratio at uprate actually exceed .75, I think it was around .82, .82. their recommendation was that they believed it was okay to go forward, but they recommended monitoring those feedwater heaters going forward to make sure there is not an issue.

So what we are done and we are basically getting baseline examinations, eddy current examination for the drain cooling sections of our two number 5 feedwater heaters prior to uprate. We did one of them last year, we're going to do the second one this year so that we have a good comparison point.

The last time we had inspected those heaters were back in 2002 as part of our normal heat exchanger inspection program. And the one we looked at last year when we compared the eddy current results to the previous one in 2002, we did not see any changes. So the expectation is the second one that we do this year we'll see the same thing. But we'll have a clean baseline for assessing what we see after we do the uprate.

So the plan is that the first refueling outage after uprate we will go back in and do an eddy current examine both those heat exchangers to confirm that there are no indications of vibration damaging occurring.

The second set of major heaters effected by uprate are our moisture separator reheaters. We have basically four reheaters. We have single stage reheating, but we have four MSRs. Again, they were retubed in the early 1980s, again, to get cooper alloy out and I think to put stainless in.

Additionally, we have had problems with the reheater design on thermal performance. And we thought we were getting excessive carryover moisture from the separator into the bundle design, which is probably why we were having thermal performance issues with the steam outlet temperature.

TEI or Southwest Engineering at the time was responsible for designing those new tube bundles. So we went back to them to ask them to update their analyses for the uprated conditions. They redid their analyses for the uprated conditions and their conclusion was that the design was acceptable. We had around 15 to 20 percent margin between the velocity and the critical velocity.

The final major heat exchanger in the system is the condenser. We retubed our condensers in 1995, replaced tubing with stainless steel tubing. As part of that tube bundle replacement in '95, we staked our entire tube bundle.

Stone & Webster evaluated our condenser for uprate on tube span for the uprated conditions using the methodology in HEI for condenser design for maximal allowable span. And the calculations concluded that we had adequate spacing presently based upon the calculations. And the only reason why that's the case is because we staked the bundle in '95. If we had not staked the bundle in '95, we would have had to have done a condenser staking operation to support uprate.

The other vibration program we have is the vibration monitoring program, which is primarily for piping that we will use to assess potential impact of uprate on piping vibration. It's basically composed of two parts, like everybody else who has probably come before you. Basically a pre-EPU assessment of vibration levels in the process piping systems; main steam, main feedwater extraction, reheater a couple of others. But all the systems that basically see increased flow due to uprate.

And basically there's a two part baseline. It's an initial walkdown, visual walkdown of the system to identify areas where there are possibly noticeable indications of vibration. We did that with Stone & Webster, I believe, last week. And they're putting the results of the walkdown together. And then based upon that we're going to identify locations where we have vibration levels that we think we need to monitor going forward. We'll put monitoring equipment on, be it handheld or permanent will depend upon the location, and get a baseline indication of what the vibration level is presently. And then after we come out of our uprate outage we will basically repeat that process, do the visual walkdown again to verify that we don't see any new indications of vibration. And also to go in and compare those places we monitored now, to monitor them again at EPU and assess any changes in vibration levels. And then depending upon what we'll see, we'll evaluate the results and take whatever actions are appropriate if there are any areas where we see vibration that we need to basically deal with.

CHAIRMAN DENNING: I'm not quite understanding. Are you talking about monitoring instrumentation?

MR. DUNNE: We will install -- yes, be it an accelerometer or a displacement probe or velocity probe. We haven't figured out exactly what we're going to install, but we are going to put monitoring instrumentation at select points. And we haven't figured out the list yet because it's going to be base don our visual walkdown on the system that we will then go in and present instrumentation values be it acceleration velocity or displacement. And then repeat that at those same locations at the EPU conditions to assess deltas, if you will, due to the uprate.

MEMBER SIEBER: This is portable instruments or permanent ones, or you don't know?

MR. DUNNE: We haven't decided yet. It may be a combination of both. It may be all portable, it may be a combination of portable and permanent.

We have used operating experience in setting up our monitoring program. And specifically Stone & Webster has been involved in a lot of uprates where they have done this activity and so whatever they've learned from all the walkdowns they've done, they've incorporated into the program.

We've also gone through basically action report condition reports at Ginna to figure out any areas where historically we may have noticed vibration to make sure that review those and assess them going forward. And we also have reviewed the other operating industry experience reports that are on INPO to see what other lessons learned we should incorporate into our program.

For example, someone a couple of years ago and came out and they had an instrument to basically fail. We're making sure that our visual walkdown includes all branch lines including instrumentation off of the main process lines that are seen in the high flows.

MEMBER SIEBER: Now do you have motor driven or steam drive feed pumps?

MR. DUNNE: We have motor driven.

MEMBER SIEBER: And so at low power levels you're putting a big pressure drop across your feed reg valves?

MR. DUNNE: That's correct.

MEMBER SIEBER: You get a lot of vibration there?

MR. DUNNE: We probably do. Typically we don't go in and monitor at transient operating points because typically you will get higher vibration levels than you will at your normal operating point. That the last --

MEMBER SIEBER: That's usually when the valve falls apart.

MR. DUNNE: Yes. So that's the last portion of the monitoring program.

We do have a rotating machinery vibration program presently which involves periodic monitoring of the major rotating components in the plant, basically the feed pump, heater drain pump, circ water pump, condensate pump, etc. Right now that's monitored on a monthly bases. We have baseline vibration readings for the pumps, the motors for our main feed pumps. We have a speed increaser between a motor and the pump. We monitor vibration from that component. So we have that baseline.

And typically after any refueling outage our rotating equipment analyst goes around and basically walks through all those components to make sure there's been no change versus what our values were before We will be doing that activity as part of our power accession program.

MEMBER SIEBER: Now I think I read where you're replacing motors or pumps in your feedwater system?

MR. DUNNE: We are putting new main feed pump impellers into our existing pump casings to basically get increased capacity. Because of that increased capacity we're putting larger sized motors. So we have to rebaseline those components anyway to get a new baseline reading.

We're also putting in new impellers in our condensate booster pumps.

MEMBER SIEBER: And your output pressure

for the pumps will be higher because T_h is higher?

MR. DUNNE: Our T^h is higher. Our steam drainer pressure is going to be slightly higher than when we operate now, but not appreciably. Right now we run with a steam generator outlet pressure on the order of around 770 psi at the steam generator nozzle. And at uprate we expect that that value will go up to 800. Basically what we're trying to do is increase the steam generator pressure to cover the increased frictional loss in the main steam line so that the inlet pressure to our turbine --

MEMBER SIEBER: Right. It about the same?

MR. DUNNE: -- is basically the same as what we have right now. And it's the turbine design that controls that.

MR. DUNNE: That's going to put more pressure on your fed reg valve.

MR. DUNNE: Right. Now what we need to do is because the main feed pump impeller was going to give us comparable pressure drop characteristics to what we have presently. But right now we throttle out of the system about 200 psi across our main feedwater valves. So what we're basically doing is putting --

MEMBER SIEBER: Is that all? I would think it would be more than that.

MR. DUNNE: Yes, it's around -- I think it's around 200.

MEMBER SIEBER: At full power?

MR. DUNNE: Yes. Full power. Yes.

MEMBER SIEBER: Okay.

MR. DUNNE: Okay. Yes, at low power it's a very large number.

MEMBER SIEBER: Okay.

MR. DUNNE: Actually, at low power it may not be as large as you think because at low power the steam generator pressure is higher.

MEMBER SIEBER: Right.

MR. DUNNE: At zero power we run a 1,000 psi. But you got more head -- you got more head on --

MEMBER SIEBER: It's nearly closed.

MR. DUNNE: Right. You've got less flow and you got more head on your pumps, you got a larger pump discharge pressure.

MEMBER SIEBER: Yes. Well, it's something for you to watch.

MR. DUNNE: Yes. And that's all I had on the vibration monitoring program.

The next thing I want to quickly go over is flow accelerated corrosion program. Ginna does have a flow accelerated corrosion program presently that we're maintaining. It basically involves the CHECWORKS, EPRI CHECWORKS computer program in combination with actual plant readings on wear rates on the various components are a part of the system. And eery outage our flow accelerated corrosion engineer goes around and has probably 100 or 200 components that he identifies to go in and get actual thickness readings so he can assess what the change in wear rates has been. And then he rolls that back into his program.

Obviously with increased flow rates changes in pressures and temperatures and quality in your piping systems you would expect there's a potential impact on the corrosion rates.

For the uprate what we've done is we've taken the CHECWORKS program and used it to analytically predict the wear rate based upon the existing process conditions. And then go in, put in the new uprate conditions and look at a change in wear rate, an analytical wear rate.

And in our submittal, if I can get this thing to work, we included this table in our licensee submittal to the NRC where we went around and basically tried to touch all the major systems that are part of the FAC program and look at components that have wear rates presently to assess what the change in the wear rate would be analytically due to the EPU conditions. So I believe it's the column all the way over at the right that tells you the percent change and the wear rate due to EPU. And the numbers, depending upon the system, vary anywhere from about 2 or 3 percent up to as high as 24 percent.

MEMBER WALLIS: So it's the extraction steam line that's the most sensitive here, the one that's wear in the fastest?

MR. DUNNE: And that may not be too surprising. That's a wet system.

MEMBER WALLIS: It's because of the materials that you're using, too, isn't it?

MR. DUNNE: It could be.

MEMBER WALLIS: It's two phase?

MR. DUNNE: It's two phase, and that probably has a large part to it. We've gone through the plant and have changed out a lot of materials from the original material that was susceptible to wear to basically a chrome molly material.

MEMBER WALLIS: So how long are they going to last, these pipes now?

MR. DUNNE: Well, that will depend upon --

MEMBER WALLIS: Your 5 mils per year or

something you're losing?

MR. DUNNE: It depends upon where you're talking. Which component?

MEMBER WALLIS: It's not changed all that much?

MR. DUNNE: No, it doesn't. So basically what's happening is we're in the process right now -- if I can get out of this.

MEMBER WALLIS: Well, it's not really a safety issue?

MR. DUNNE: No.

MEMBER WALLIS: It would be embarrassing to lose a section of steam line, but it's not really a safety issue.

MR. DUNNE: I guess a couple of things I would like to say is that --

MEMBER SIEBER: It's not a nuclear safety issue. Personnel safety more than nuclear safety.

MR. DUNNE: Basically we have added components to the FAC program based upon the uprate. For example, the piping between our number two feedwater heater outlet and on our number 3 feedwater heater inlet is presently out of the program because the temperature doesn't exceed 212 degrees. It's around 208, 210. At EPU it's going to be over 212.

So it's in the program now. Now it's basically about five feet of pipe, there isn't much there. But we will be adding that to the program.

And also based upon the analysis of the feedwater heaters that was done by TEI, we have a lot of feedwater heater nozzles where we have high velocities. Most of those nozzles are already in our emersion corrosion program because of temperature and quality, but there were a number of them that weren't. For example, our low pressure feedwater heaters that see 150/160 degree water would be out of the program. We are adding them into the program because of high velocity to monitor wear on those nozzle due to the increased velocity that we see under EPU conditions.

So we do not have any components that need to be replaced. We will be increasing the number of components that we basically sample going into our 2006 refueling outage. That will be at the discretion of our emersion corrosion engineer based upon what he sees after he updates his entire program. And then going forward we will monitor components and look at actual wear rates based upon plant data and assess our inspection frequency as needed.

Okay. The final thing I'd like to quickly do is go through and just go over what effect the uprate has had on our various cooling systems, they're primarily safety related cooling systems.

The approach we took at uprate going into it was to assume that all of our cooling systems would function the same as they do right now. Do all the evaluations based upon the existing cooling capability and then assess whether that was adequate or whether changes needed to be made to the system. And that's the approach we took. So what this basically does is tell you where we found out we didn't need to make changes versus where we had to make changes.

Safety injection system, which is primarily used for large break/small break LOCAs, we used the existing flow capability that we have for the present operating condition. And basically based upon the Pclad temperature numbers we're getting, there's no need to change flow capability.

Additionally contain the spray system which is for containment pressurization. We used the existing design flow capability. And, again, since we were able to show that containment pressure are below design, there was no need to change its functional requirements.

Aux feedwater system. At Ginna --

MEMBER WALLIS: So many plants have upper plenum injection.

MR. DUNNE: Excuse me?

MEMBER WALLIS: You have upper plenum injection --

MR. DUNNE: Yes, we have upper plenum injection.

MEMBER WALLIS: -- which is rather unusual.

MR. DUNNE: We are rather unusual.

MEMBER WALLIS: Are there many other plants that do that?

MR. DUNNE: There are a couple. Kewaunee, I believe, has it.

MEMBER WALLIS: Well, it's just a few, very few?

MR. DUNNE: Just a few, yes.

MEMBER WALLIS: All right. It's not an issue, I was just curious.

MR. DUNNE: No. We are an upper plenum injection plant.

Our aux feedwater system, we actually have two aux feedwater systems. The preferred aux feedwater system and a standby aux feedwater system. And as mentioned earlier, we have a total of five pumps in those two systems.

Our preferred aux feedwater system has two motor driven aux feedwater pumps, nominal design requirements of 200 gpm. And they're aligned to individual steam generators. And then our turbine driven aux feedwater pump is a 400 gpm system that basically is supposed to deliver 200 gpm to each generator.

Because of potential high energy line break concerns since all our aux feedwater pumps are in the same general area, there was a potential for a high energy line break that could take out all the pumps. In the mid-'70s we added a separate standby aux feedwater system which has two more 200 gpm pumps completely independent of the preferred. It's basically pumps that we never operate. They are basically a backup to our preferred aux feedwater pumps. We don't use them for normal plant cool down or anything. They're basically, again, backups. Because they're backups there is no automatic actuation of those pumps, it's all depending upon manual operator action from the control room to basically start the pumps and align them to the steam generators.

MEMBER SIEBER: You're preferred aux feedwater is still 200 gpm per steam generator?

MR. DUNNE: Yes. Yes.

MEMBER SIEBER: But you sacrifice margin?

MR. DUNNE: Yes, we have. For example, we don't --

MEMBER SIEBER: How much margin do you have left?

MR. DUNNE: Well, what happens is at the existing power level we don't need 200 gpm. We need around 170 gpm. And so for uprate the analysis -- I believe the last analysis showed we needed 195 gpm. So it's still within the capability of our 200 gpm system. Obviously there's less margin, again with an increase in decay heat you're going to get less margin. Just a fact of life.

Now our standby aux feedwater system, it's also a 200 gpm system, however because it requires manual operator action, it does not get an automatic actuation signal, so if you bring it into a high energy line break concern later in time than you would the preferred system. And basically at the uprated conditions the 200 gpm flow capability we presently have was not sufficient to meet the acceptance criteria for the analysis. The analysis Westinghouse did at uprate said we needed 235 gpm delivery capability to the generator for a feedwater line break, which they analysis as a loss of feedwater event.

MEMBER SIEBER: But the standby system is there for Appendix R, I take it, and --

MR. DUNNE: It's high energy line break and Appendix R, yes. And for --

MEMBER SIEBER: But it's manual, you can't take credit for it?

MR. DUNNE: We can take credit for it for the high energy line breaks that it was put into to mitigate.

MEMBER SIEBER: Right.

MR. DUNNE: Basically --

MEMBER SIEBER: You don't have a lot of margin?

MR. DUNNE: So we need to increase the flow capability. The pumps are actually 600 gpm pumps. So the pumps themselves are not an issue. So what we ended up doing and to get 235 gpm, we basically have to decrease the hydraulic resistance in the flow path which got us into this modification to change out an existing flow control valve on the discharge with a larger valve, basically, so that we can pump 235 gpm into a generator at a code safety valve setpoint, basically.

Additionally, like you mentioned, we use our standby aux feedwater pumps for Appendix R scenarios. Ginna has this unique required capability of doing -- going to cold shutdown using the steam generators in a water solid mode where we use standby aux feedwater.

MEMBER SIEBER: Right.

MR. DUNNE: If you get down to a normal RHR tie in and you don't have RHR and you want to go to cold shutdown, basically what we would end up doing, we would steam the generators down with atmospheric dumps for a period of time and get as low as we could, and then transition to basically water solid steam generator cooling where we start at standby aux feedwater and basically pump water into the steam generators and take water out through the main steam lines to reflect that.

Now for that uprate has effected that flow capability. Presently for the present power level we need, I believe, 225 gpm. Going to uprate because of the increase in decay heat, we need to go up to 250 gpm.

Now from a pump point of view it's not really an issue or from a hydraulic resistance point of view because when we do that the steam generator pressures are down around a couple hundred psi so you've got excess head margin on your pump to be able to put that flow into your generators. So it's not really that scenario that's controlling our modification. Our modification is being controlled by our need to be able to put water into the generator for a high energy line break event where the generators are sitting at a code safety valve setpoint of basically 1085.

The other systems that are obviously affected by uprate by decay heat removal systems. For Ginna that basically entails three different systems or our residual heat removal system, which basically is the primary path. That rejects heat to our component cooling water system, which is an intermediate loop, and then the component cooling water system in turn rejects heat to our service water system. The service water system uses Lake Ontario as its water source. And it delivers the water back to Lake Ontario, which is our ultimate heat sink.

So basically, again, we evaluated the capability of those systems to handle both normal shutdown and accident long term containment cooling with the existing heat removal capability. And in general they can still support both normal shutdown and long term cooling and containment. Obviously, the times required to get to cold shutdown have lengthened out and the times to depressurize the containment have lengthened out because of the increase in decay heat, but we're still able to meet our functional requirements.

The last system is spent fuel pool cooling, which is obviously another one affected by decay heat. For spent fuel pool cooling our requirements are for a full core offload, we will not initiate a full core offload until the cooling capability of the system can match the decay heat load in the pool. That's in our technical requirements manual whenever we do a full core offload, we have to do a cycle specific analysis of our cooling capability, which will take into account lake temperature, whether it's summer, spring or fall and--

MEMBER WALLIS: Are there any trends in lake temperature with the years? I know there's rather peculiar years recently, but are there other trends with the years that we should need to take into consideration?

MR. DUNNE: We don't believe so yet. But--

MEMBER WALLIS: Not yet?

MR. DUNNE: I mean, we can go back and look at a ten year history and we'll find some years where it gets hotter than others. For example, last summer it was a very hot summer, probably the hottest we've had in the last ten years. But the summer before it was very cool, one of the coolest ones we've had in the last ten years.

Now to address that what we did -- what we have done is raised our design basis lake temperature. Not as part of uprate. We did that a couple of years ago. It used to be the design basis lake temperature for Ginna was 80 degrees because historically you very rarely exceeded 80 degrees. But every time during the summer when the lake would start going up to 75, 76, 77, everybody would get in a fit about are we going to exceed 80, what are we going to do. And we'd start to put JCOs in place and then the lake would cool off and we'd never use them. But there were about four or five summers where we do that.

So about three or four years ago we went through and did a 5059 to increase the design basis the lake temperature from 80 to 85. We don't expect ever to see 85 degrees. We might see 80 on a hot day occasionally. But we will not see 85. At least not while I'm working, anyway.

MEMBER SIEBER: What you need is a lake cooling system.

MR. DUNNE: Yes. And Lake Ontario has this unique feature of turning over on us every now and then where the lake temperature will go from that 75 degrees to like 40 degrees in five or six hours. But we haven't figure out how to predict that.

And unless there are any other questions, that's all I have.

CHAIRMAN DENNING: Good. Thank you.

MR. DUNNE: And I think I turn it over to the NRC.

CHAIRMAN DENNING: Do we want to go with a break now?

MR. MILANO: We can do it either way.

CHAIRMAN DENNING: Let's do that. It's 3:22. Fifteen minutes, let's make that 3:40. All right.

(Whereupon, at 3:22 p.m. off the record until 30:40 p.m.)

CHAIRMAN DENNING: Okay. Next speaker.

MR. MIRANDA: Right. The rest of the afternoon is going to be taken up by presentation from the NRR Staff. We're going to start off with our Reactor Vessel Materials Reviewer, Neil Ray, who will provide the reactor vessels and internals review. And following him from that same organization talking about the reactor coolant pressure boundary materials will be Timothy Steingass.

Neil?

MR. RAY: Good afternoon. By this time you know that I am Neil Ray from NRR, materials engineer.

We looked into the effects of this EPU on reactor vessels materials properties and its impacts and also on the reactor internal and core support materials.

Now, reactor vessel integrity when we call it integrity, we looked into surveillance capsule program. Because of the EPU there will be the possibility of reactor vessel clearance, and that may impact surveillance capsule program, so we looked into it.

We also looked at additional effect on the reactor vessel integrity. And as I said, we looked into the reactor vessel internals and core support materials.

Regarding surveillance capsule program, because the EPU fluence is greater than 200^{o}F, that's not a surprise it was there before. And as part of ASME standard still they have to have 5 capsule withdrawal. Four capsules already withdrawn from that Ginna vessel, and fifth capsule is planned for withdrawal at 5.45 E19, which is the EOL. When I say EOL, keep in mind that is extended life not our intended of life. SO EOL is 5.45 E19. So that basically says between one to two times the peak EOL fluence, which is perfectly all right for ASME standard.

MEMBER WALLIS: So it meets the boundary by less than one percent accuracy.

MR. RAY: That's is correct. That is correct.

MEMBER WALLIS: Which is probably not as accurate as you know the fluence anyway. It's the same as we had before, isn't it?

MR. RAY: Yes. Okay. So there is no basically on surveillance capsule program. Just to tell you for that, they are planning to --

MEMBER WALLIS: Well, suppose that it was not just over the limit, would they then withdraw it at a different time or something?

MR. RAY: Yes.

MR. WROBEL: Yes. Can I answer that? George Wrobel from Ginna.

Yes. Right now I think you were going to say we're going to withdraw in 2006. We refined our calculations a little bit and we're going to wait until 2008 to make sure --

MEMBER WALLIS: So you have plenty of flexibility there?

MR. WROBEL: Excuse me?

MEMBER WALLIS: You have plenty of flexibility.

MR. WROBEL: We have plenty of flexibility in that withdrawal.

MR. RAY: Yes, they do. Actually, in a sense, just off the record the letter that we have done is better for them also. Because you are talking about 60 years. And they have the last capsule they're planning with withdraw when it's predicted to be accumulated 80 years. That is the capsule end, I suppose.

Okay. That's all about surveillance capsule. Let's move into the other area that the radiation embrittlement may impact, that is the pressure temperature limits, upper shelf energy, pressurized thermal shock.

Now pressure temperature limits is a fairly straightforward. What happened is their current limits is applicable up to 28 EFPY. And that is based on the cumulate fluence of 3.11 E19 and the corresponding adjusted reference temperature they calculated. Now because of the EPU and the new calculation methodology and in the meantime the fluence design differences, their cumulative fluence with EPU is reduced, which is 2.01 E19 n/cm ^{2} (E>1.0 MeV). So obviously every other parameters in developing pressure temperature limits remaining constant so their current pressure temperature limit is bounding, and so there is no impact whatsoever in terms of pressure limits.

Is there any question on that?

MEMBER WALLIS: So the fluence of the EPU is less than --

MR. RAY: Yes, I know somebody will ask that question.

MEMBER WALLIS: Is this because they've used a different method or something?

MR. RAY: Well, there are two possibilities. One is you have to keep in mind this pressure limit they've allowed several years ago. At that time from that point onwards they probably have low leakage goal,number one.

Number two, they have a different procedure in calculation. They've withdrawn the capsule so the dosimeter, everything put together they are ready for -- it kind of surprises most of the people, but it does happen all the time.

MR. WROBEL: Again, George Wrobel from Ginna.

We did use the Reg. Guide 1.190 methodology which is more accurate we think.

MR. RAY: Yes.

MR. WROBEL: But you know the original methodology was a lot more conservative than that. So it looks like we have a lot margin that we gained.

MR. RAY: Yes. Okay. So that's what I did, don't have to do anything with the PT limits. It will be applicable up to 28 year EFPY and prior to that, they have to generate new PT limits, which will be applicable probably up to 54 year period or so.

MR. WROBEL: Yes. We've currently done the analysis out to 32 already. We haven't submitted that, but that's been completed.

MR. RAY: Okay. Now regarding upper shelf energy, except two particular waves -- waves are always a problem, as we all know, for upper shelf energy and PT issues. And in this case they have intermediate-to-lower shell girth weld and the intermediate-to-nozzle shell. Both of them dropped below 54 pounds based on Reg. Guide. So as you all know that there is a ASME Code, Section XL Appendix K calculation that always gives you green signal and you move ahead. That's exactly what they did and that's perfectly all right. So there is no upper shelf energy problem. That's in a nutshell. And we verified their calculation as well.

Pressurized thermal shock. Well, again, because of the increasing fluence there end of life, again 54 or up to extended life, was 270.6. Now it increased to 273 using the EPU fluence which is no nevermind, because our screening criteria all software needs 300. So they have enough margin there.

So PTS is also not a problem.

Now regarding the reactor internal and core support materials, currently they are following ASME Section XI inservice inspection program with PT1 and PT3 procedures. And they committed that they will participate and follow whatever comes out of the EPRI MRP program, which we are all anxiously waiting for at this moment. We don't know what will come out. But they committed, they will follow through and they will let us know. And that perfectly fulfills our Review Standard RS-001.

So in conclusion we looked into the areas that the reactor vessels and internals and it looks, all of them, pretty good in a satisfactory margin.

There is no significant that concern us that we can think of. So I think they're in good shape.

Any questions, any part of that discussion? Thanks.

CHAIRMAN DENNING: Thank you.

MR. MIRANDA: Tim?

MR. STEINGASS: Good afternoon. My name is T.K. Steingass. I was introduce as Timothy, and I haven't been called that in about 30 years.

I'm a material engineer in the Flaw Evaluation and Welding Branch.

I want to talk about the reactor coolant pressure boundary, how the EPU effects or I evaluated how or what effect the EPU may have on the reactor coolant pressure boundary.

The review covered the specification compatibility of the reactor coolant, fabrication and processing, material susceptibility to degradation, the degradation management programs that were in effect -- that will be in effect, EPU impact on failure mechanisms and leak before break analyses.

The degradation mechanisms that I looked at were under austenitic stainless steels and the reactor coolant pressure boundary, what impact EPU may have on the acceleration or impact on IGSCC. Of course, we're concerned with the sensitized microstructure and the effect of the EPU on the hot leg is only 8.6°F.

Transgranular and stress corrosion cracking, through the introduction of halogens that may aggravate that failure mechanism. So, as I said before, the 8.6 degree increase and the slightly elevated chemistry of 3.5 ppm lithium is still within EPRI guidelines. Therefore, those two failure mechanisms are not accelerated or aggravated through the EPU.

For alloy 600 and 82 and 182 welds, what the major concern is PWSCC as we've seen in the Davis-Besse head. For Ginna the reactor head was replaced in 2003 with alloy 690 material which will probably start cracking further on down the line than the first one did.

Other susceptible program or other susceptible components like the thimble tubes, welds in the bottom head, they're still going to be susceptible to PWSCC, of course. But again, the EPU does not introduce any new failure mechanisms or accelerate that. So consequently there's still going to be cracking, but under the license renewal application process I looked at whether or not there were existing programs that would manage or aging management programs to assure that these components will still remain operable and perform their design function.

These programs were approved by the staff, these aging management programs, under NUREG-1786. Consequently, I came to the conclusion that the effects of PWSCC will be adequately managed.

MEMBER SIEBER: Now when you talk about increase in temperature is 8.6 degrees in the hot leg.

MR. STEINGASS: Yes, sir.

MEMBER SIEBER: That's an increase in the nominal temperature based on what their operating parameters are now planned to be as opposed to the maximum that they could be allowed, I take it?

MR. STEINGASS: That's correct.

MEMBER SIEBER: On the other hand, there's nothing that would prevent the operators of the plant from moving to a higher hot leg temperature and still be within the bounds of the approved EPU?

MR. STEINGASS: Due to a power excursion or just --

MEMBER SIEBER: No. I mean as a regular way of operation, day-to-day operation. Because you know they've been given a range of values where they can operate and they have chosen ones that give them a T_{Hot} temperature of 609, but they could go as high as, what, 617?

MR. DUNNE: This is Jim Dunne.

During a cycle that won't happen. I mean, we have a --

MEMBER SIEBER: Well, that's because you chose to operate --

MR. DUNNE: Yes.

MEMBER SIEBER: -- where you're at.

MR. DUNNE: Yes. They can --

MEMBER SIEBER: But there's nothing in our rules that would prevent you from increasing that.

MR. DUNNE: We could increase up to the 576 number with a value with a nominal dead band around that, which is nominally I believe 2 degrees. But we wouldn't be able to go in and say we're going to start operating the plant at 578 normally, because that would be outside the span that we've done the analysis for. We'd have to reanalyze the plant for going to a Tavg temperature greater than 576.

MEMBER SIEBER: Okay. I'll have to think about that for a little bit. But it just seems to me that you could change Tavg and your ultimate T_{Hot} without additional interaction with the Staff. And if you had 82, 182 weld buttering someplace that could accelerate, it's aging.

MR. WILSON: This is David Wilson, Ginna.

If we made changes like that, our commitments under license renewal requires us to reevaluate the programs also and evaluate whether or not the conclusions of the Staff agreed to our extended operating license were still valid. And perhaps even have to go back and get approval to do it because of the license renewal programs.

MEMBER SIEBER: Okay. Well, like I said before, that's something that I would have to check on.

Does the Staff agree that they would have to come back?

MR. WILSON: Well we'd start under the 5059 process, of course.

MR. MIRANDA: That's what I was going to say. Even though they had some margin in the band of what they could operate to --

MEMBER SIEBER: Right.

MR. MIRANDA: -- if they did decide to it, that their 5059 process drives them to have to evaluate it, the license renewal commitments are part of the licensing basis of the plant and that would dictate, you know, whether or not there's a need for prior NRC approval.

MEMBER SIEBER: Okay. Under my postulate circumstances, would they be required to come back?

MR. MIRANDA: I couldn't answer that right now.

MEMBER SIEBER: Okay.

MR. STEINGASS: Another thing I looked at was the leak before break analyses. Does what these people do and what these people pretend to do have any impact on the existing leak before break analyses.

So I looked to determine if the analyses were impacted by the EPU under WCAP-15837. The leak before break analysis of the primary loop piping and reactor coolant pump casing was performed in 2002 for Ginna under their license renewal application. The people at Ginna evaluated the impact of the EPU on the conclusions reached in their 2002 leak before break analysis, which was approved by the Staff in NUREG-1786.

The review summary 001 lists under SRP Section 3.6.3 the following acceptance criteria for a leak for break analysis. A margin of 10 on leak rate; a margin of 2 on critical flaw size, and; a margin of 1 of loads.

The evaluation done by the licensee showed that they met the acceptance criteria. For EPU they had a margin of ten, on critical flaw size a margin of 2 and a margin of 1 for loads.

Consequentially, I came to the following conclusion. The licensee has adequately evaluated the effects of EPU or reactor coolant boundary materials. No new failure mechanisms have been incorporated due to the EPU.

The licensee has appropriately identified aging management programs to address effects of changes in system operating temperatures. And this was done on a license renewal application process.

The licensee has demonstrated that a leak before break analysis remained valid under EPU conditions. Consequently per the review summary 001 Matrix 1 design criteria 1.-4,-14, -31, 10 CFR 50 Appendix G and 10 CRF 50.55(a) requirements have been met. And that's all I have.

MR. MIRANDA: All right thank you.

MR. STEINGASS: You're welcome.

MR. MIRANDA: Okay. Continuing on to the next area is Kamel Manoly. He's the Chief of the Mechanical Engineering Branch.

MR. MANOLY: Good afternoon. I'm Kamel

Manoly, Chief of the Engineering Mechanics Branch in Division of Engineering.

And we have Dr. John Wu, the leader reviewer for the power uprate.

Okay. The first slide basically shows the components that were evaluated in the Ginna power uprate. Typically it would be the vessel and internals and the nozzle and supports.

Like to note that the vessel was designed to ASME 1965 edition and the NSSS was designed to the ANSI 1967 with '73 addenda. So the NSSS did not have the traditional fatigue analysis as the more recent plants do.

We also looked at the replacement steam generators and the reactor coolant pump, pressurizer and supports and vessel BOP piping system and supports and also the components, valves, MOVs, AOVs and SRVs.

We typically evaluate the methodology and the loads applied, and calculated the stresses and usage factors. The primarily one would be for the vessel because explicit fatigue analysis whereas for the other components the NSSS of you use then ANSI 1967 then the '73, it doesn't have explicit cumulative uses factor like Class 1 components.

We also looked at the functionality and

impact of EPU on the three major GL 89-10 and 95-07. And I believe also we looked at on GL 96-06, I believe.

And we also looked if there's any conflict between the EPU and the license renewal and the evaluations covers the 60 year span.

And finally then NSSS and BOP piping systems and supports.

I'd like to note that Ginna's approved for the leak before break criterion, which eliminate pipe breaks ten inches and larger. So the limiting break sizes were obviously in the smaller lines 3 inches and 2 inches. A specific evaluation was done for the safety injection line, the hot leg and the 4 inch upper plenum injection line connected to the vessel.

The finite element analysis using the ESTDYN code, I believe that's a Westinghouse code, and compared the stresses using the ANSI B31.1 limits and ASME what are applicable.

CHAIRMAN DENNING: Could you speak up just a little bit.

MR. MANOLY: Okay.

CHAIRMAN DENNING: Thanks.

MEMBER WALLIS: I'm sorry. These calculated stresses were stresses all calculated by the licensee?

MR. MANOLY: Yes.

MEMBER WALLIS: What did you do to satisfy yourself that they had done this correctly?

MR. MANOLY: We looked at the summary of the analyses. We did not do -- we don't do an additional analysis to verify what they have done. We just look at the results and see if it's reasonable and --

MEMBER WALLIS: You look at the basis for the results?

MR. MANOLY: Yes. Yes. And, obviously, every power uprate has it's own uniquenesses. And for this power uprate probably the things that comes to mind the most is vibration issues of the components and the steam line. And that's where we did the most focus on areas where we expect, you know, issues can come up.

We note that the result of the EPU, the licensee upgraded nine supports and added one support in main steam line. And added also one support in the feedwater line to address the effect of increased flow.

I think the first bullet points that we verified that they account for 60 years of operation to show that the fatigue limits does not exceed the value of one.

We looked at the effect of flow on vibration on the steam separators because it's expected to increase the EPU. And it was found acceptable. The concerns in the boiling water reactors is very different than for the pressurized reactors. The flow here is pretty much parallel to the primary tubes so you don't get the cross flow that would invite flow induced vibration issues.

And also the separators are basically a very rugged which are not going to be amenable to the flow induced vibration as you would expect in the steam dryers and the boilers.

CHAIRMAN DENNING: When you said "judge to be acceptable," what quantitative guidelines did you use?

MR. MANOLY: Well, we know that that design of a generator has been used before. They did the testing of the new dryer I think the facility in Canada. So they did testing of that dryer itself. And there are several plants that use the same design at a higher velocity coming from the restricting nozzle than from Ginna. And there hasn't been really any issue. So operation really is the best test of a component.

CHAIRMAN DENNING: Incidently, that type of insight helps us quite a bit in evaluating statements like this.

MR. MANOLY: Yes. I can tell you the steam velocities through the flow restrictors after the EPU are lower than steam velocities at similar plants like Byron, Braidwood, McGuire and Catawba. So there hasn't been any issue there, so I wouldn't expect that to have any issue here.

MEMBER WALLIS: So these notes that you're referring to, are they part of the public record or are they your own private notes that --

MR. MANOLY: No, this was in application.

MEMBER WALLIS: So the numbers you're quoting to us are from their application?

MR. MANOLY: You mean the velocities? I didn't really give numbers. I'm just saying the number was lower than.

MEMBER WALLIS: Yes, but those numbers you've just given us, is that document you're reading from, is that part of the public record?

MR. MANOLY: Yes. This is from the application itself.

MEMBER WALLIS: From the application?

MR. MANOLY: Yes. Yes.

MEMBER WALLIS: So it's not something that. you dug out yourself?

MR. MANOLY: No. No. Well, RIAs back and forth. But that's also in the public record.

MEMBER WALLIS: Well I just wonder when the Staff has all these judge to be acceptable statement and we don't know why, there is a paper trail somewhere that it could be investigated if necessary.

MR. CARUSO: Yes, there is.

MEMBER WALLIS: There is.

MR. MIRANDA: We have the application, we have all the RAIs.

MEMBER WALLIS: And you have all the RAIs? And that includes everything that justifies this "judged to be acceptable" statement?

MR. MIRANDA: Everything that's been publicly documented, yes.

CHAIRMAN DENNING: But there's no trace line, though, that --

MEMBER WALLIS: Is there a trace line of your rationale somewhere?

MEMBER SIEBER: No, it doesn't say why.

MEMBER WALLIS: It doesn't say why. Then

why is the key question, though, isn't it?

MEMBER SIEBER: Yes.

MR. MANOLY: Sometimes the why is it meets the code limits, sometimes why is -- like here for the monitoring after the operation going to using OM standard. If they meet the OM standard for vibration, that will be the reason.

CHAIRMAN DENNING: But if it isn't the SER, then there really isn't a --

MR. MANOLY: Oh, no, definitely. I mean we say that -- where it meets certain code limits or, you know, vibration testing limits, those are the basis that constitute acceptance.

CHAIRMAN DENNING: Continue. Oh, you mentioned there's a slight increase in flow rate and induced vibration in the U-bend tubing?

MR. MANOLY: Yes. Yes. But they evaluated that and found the -- see, the acceptance limit here is the stability ratio is less than one. So if it shows it's less than one, then that will be acceptability. I mean, that is the criterion for acceptance based on analysis that was done.

MR. WU: This is John Wu.

About flow in this vibration evaluation, normally we looked at the flow induced vibration, you know, the -- what the maximum is and what it's close instabilities is going to have close -- and I don't know why it's look at -- you know, even it's low but sometimes you look at the past experience because it's the operating experience compared to, you know, the seeing the prints and we do that.

For this one like the four separator, you look at that-- this can do, I think it's B&W Canada, they were similar plants, about 44 steam generator in Canada, about 34 in United States, it's a similar plant. And there's no failure, no records of any indication at all. So this is very sturdy.

And I talk about showing this vibration normally we look at instability like -- instability through such a instability number. And which is normal in their criterion is pretty low, probably -- maybe -- you know, normally we look at less than one and that is instability. Less than one where we would consider acceptable. And also you look at -- like vortex shedding and like turbulence goes through. But here because the flow is parallel to the separator so it's minimal. There's no shedding. And even there's shedding, it's very small at all. Very small. Like tubing, tubing has -- so there's more shedding and more shedding. So I think sometimes they have a criteria and something like 15 -- like you know two percent of the allowance, something like that. But the 2 percent is based on the fix/fix type of -- fix/fix type.

But the idea is try to keep the trace level below the endurance limits so no matter how you shake, it won't break even for --

MEMBER WALLIS: So the best argument is that there is a lot of experience with similar steam generators?

MR. WU: Yes.

MR. MANOLY: Yes. Yes.

MEMBER WALLIS: Because the predictability of flow induced vibration from -- is not that good, as we know from some other experiences. There are some vibrations which sometimes occur as a surprise?

MEMBER SIEBER: But I think you're right, you can't tell the basis just from reading the SER.

MR. MIRANDA: Well, you can't tell the specific basis, I'll agree with you. The fact is that each section of the Staff's evaluation provides a detailed list of the regulatory requirements that the Staff had to assess against along with, you know, whether there were GDCs or whether there were some other type of regulation. And in addition, the Staff reviewed the licensee's application against both the Review Standard itself and that in part called out a lot of the original SRP sections. Albeit it that it may not say it at the end as to what specifically -- would it specifically came for a conclusion against each one of the issue. The fact of the matter is is they did review each section against those. And if they didn't, I guess the answer is in the negative. They didn't find anything in those areas so it was acceptable.

MEMBER WALLIS: Is there some record, a form of notebooks kept by the Staff member that sort of says that on a certain day I sat down to review this thing and I checked off this, this and this and I was satisfied and after five minutes I went away, or is there something that says I spent three weeks doing it and these are the things I did, and it's all written down somewhere?

MR. MIRANDA: No, it is not. That is not part of the --

MEMBER WALLIS: So if it were a legal case and somewhere were trying to find out the basis for these decision, how would they be determined?

MR. MANOLY: Well, depending on the complexity of the subject. I mean, there are certain areas where we might even do confirmatory analysis and some areas where you have a routine type review, it's not really cost effective to question things that we pretty much know the answers are pretty reasonable. So it depends on -- but the basis always has to be in the SER. Whether it's standards -- meets standard ASME limits, it's in the ASME limits or OM limits. There is always some limit that ultimately we have to point to.

MEMBER WALLIS: But what can you do? I mean if the applicant says we calculated 2921 and the ASME limit is 3000, let's say, do you just accept that?

MR. MANOLY: Well, this --

MEMBER WALLIS: What else can you do?

MR. MANOLY: But they describe the analysis. Now when we read the description of what they have done, if it seems reasonable, I'm not going to ask --

MEMBER WALLIS: So you look at their notebooks or their calculation sheets or something?

MR. MANOLY: No, no, no.

MEMBER WALLIS: No?

MR. MANOLY: Sometimes we look at the calculation if we suspect something that doesn't seem to add up. But if it seems reasonable --

MEMBER WALLIS: Don't you do some random spot checks where you do audits at plants and you say show me your calculation sheet and --

MR. MANOLY: No, no. That comes in RAI. I mean, we can ask questions in RAIs that we ask for specific documents that we need to review further. We did not do that in this application because we didn't feel the need to. I mean this --

MEMBER WALLIS: So your justification -- I mean, we have to rely on your judgment I think in many cases then, don't we?

MR. MANOLY: Well, I mean, and I think you learn -- when -- I mean for boiling reactors do you know what have been happening at steam dryers. So when we run into that we do a lot of audits. You know, John just came from an audit of Quad Cities' dryers. He's still -- you know, even though they had the license, but he's still auditing the calculations. We've been doing that for the last, probably year and a half or two because there is a cause for that.

And I think the effort, we put the effort where we can get maximum return out of the time we spend.

CHAIRMAN DENNING: You may continue.

MR. MANOLY: All right. I think John

pretty much covered this slide.

I think the first bullet basically, the reliance on the first bullet on the load downs that are going to be done prior to the power uprate is the baseline and then get evaluation that weren't continued observation of the steam line where they think that potentially there to be increased vibration.

The second bullet basically addresses that the flow is primarily parallel to the axis of the tubes. And the possibility of FIVs is respect to -- of vortex shedding is apparently very low.

And that pretty much covers this slide.

The next one is the specifics about the separators. Inspections on fatigue for flow induced vibration did not reveal any issues in previous separators. We know the design of this one is fairly rugged in the new design, so it minimizes the chances for FIV. And the velocity, as I mentioned, is fairly low. And also the -- they have a flow -- I guess like a nozzle that would capture anything of any size that potentially can break loose before it goes to the turbine.

And if anything breaks, it potentially it an get caught at the support plate inside the steam generator. This is just one of the scenarios.

But we didn't really feel that there was any concern about the separators in this plant.

CHAIRMAN DENNING: Tomorrow we're going to hear about the power ascension testing. Based upon your assessment of potential for vibration do you make recommendations as to what kind of monitoring you think should be done or where monitoring should be done to detect vibrations if they should be encountered as the power level increases?

MR. MANOLY: Well, they identified the systems, the lines that they're going to be monitoring in the application. The licensee. And they're going to do baseline walkdown first at 100 percent power, current 100 percent and then they're going to be monitoring certain locations. So we agree with the list with what they identified. They're going to meet OM code, OM3 is very conservative criteria for vibration.

CHAIRMAN DENNING: Yes. What about lack of monitoring the steam lines, is that an issue?

MR. MANOLY: They are monitoring the steam lines.

CHAIRMAN DENNING: What's that?

MR. MANOLY: They are monitoring the steam lines, I believe.

CHAIRMAN DENNING: Well it's my understanding they weren't, but it might have been a misinterpretation.

MR. MANOLY: No. I think the licensee can say. The application says they're going to monitor the steam lines. They're going to determine the portions within the steam lines that they're going to monitor.

CHAIRMAN DENNING: Can you respond to that from the plant?

MR. DUNNE: This is Jim Dunne.

Basically based on the -- we've agreed with the NRC that we should be monitoring certain locations in the plant, probably primarily main feedwater and main steam piping. We're going to use our baseline visual walkdown that we did last week to identify specific locations in both systems that we think we should monitor going forward. We haven't identified those points yet. But the plan is that there will be some monitoring of main steam line and feedwater locations based upon the visual walkdown.

MR. MIRANDA: A number of the issues that you're asking about if you look through the history of some of the later requests for additional information you'll see it where we ask questions with regard to the post-EPU conditions, whether they be flow or otherwise in comparison to industry norms and things like that. And in the course of the RAIs and discussions via teleconferences and others, we determined whether or not or we agreed with the fact that their program is focusing towards the right systems and components and stuff.

So what you're asking is is we did do it and we did it outside of the initial application review.

CHAIRMAN DENNING: Okay.

MR. MANOLY: I think this is the last slide. Yes, it's the last slide. Components. Mechanical components.

MR. MIRANDA: So that concludes the engineering mechanics portion. If there aren't any other questions, Greg Makar is going to talk about flow accelerated corrosion and some other --

MR. MAKER: Thank you.

Yes. I'm going to talk about five systems. I'm going to talk about flow accelerate corrosion, steam generator tube integrity, the steam generator blow down system, the chemical and volume control system and finally paint and other organic materials.

And I'd like to start with flow accelerated corrosion or FAC. FAC is a corrosion thinning mechanism that, as you heard from Jim Dunne, it involves an interaction between several variables, including the temperature, flow rate, the moisture content and the alloy of the components. So what's going on in the pipe and what the pipe is made of.

And we focused our evaluation on where there are changes. Because some components will experience changes in some of these parameters.

MR. MIRANDA: You want to go up one slide.

MR. MAKER: Thank you.

What we look for is scoping first of all, that the license was looking at the changes due to the EPU and seeing what effect that would have on components and whether they needed to add components into their FAC program.

And they did. They evaluated those parameters, temperature, etc. And they found, for example, cases of inlet nozzles in the feedwater systems where they had high flow rates and now they were increasing the temperature from below the threshold of about 212^{o}F to above that threshold. And those things were added into the program.

So after the scoping, the CHECWORKS, the

EPRI CHECWORKS program is one of the tools that they used to monitor FAC and manage FAC. This program allows for -- since it models system, it allows for changes and they are updating these models for the uprate conditions and provided us with -- well, you saw a table of increases in corrosion rates and thicknesses of pipes due to the EPU. And we saw changes in the corrosion rates. They increased from about 3 percent to 24 percent. And the actual corrosion rates themselves up to about five mils per year.

And this group of components that they evaluated and showed us the evaluations for covered a variety of component types and sizes and operating conditions.

So this was our basis for concluding that at EPU conditions their program will continue to manage FAC. The scoping, the fact that they used CHECWORKS and the result that they showed us.

And next I'll talk about steam generator tube integrity. The Ginna plant has replacement steam generators, replaced in 1996 with steam generators with alloy 690 thermally treated material. They also have stainless steel tube support materials.

In addition to these material changes,

there are also some design changes. For example the support structures for the tubing to minimize vibrations and also thermal treatment and design features to reduce stressed in the U-bends relative to other older steam generator designs.

The operating parameters, of course will change for the tubing. For example, the after temperature inside will be hotter. But even at the increased T_{Hot} this will still be within the range of other steam generators already operating in the fleet. There are others with higher temperatures that have been operating longer. And for this reason, although the higher temperature will increase the rate of degradation mechanisms, we don't feel it will be significant and it will be managed by their program.

The vibrations and wear of the tubes, you've heard that this has been evaluated and there is not an expectation of a lot of tube wear, but tube wear is part of the steam generator tube integrity program it includes degradation assessments that include wear and evaluations of wear if they're found.

And so based on the main guidelines we use, which are the NEI 97-06 and the associated EPRI evaluation guidelines, we judge that their inspection program will continue to manage the integrity of the tubes.

The steam general blowdown system supports tube integrity by removing impurities from the secondary coolant. And at EPU conditions there will be increases in flow rate of the system. This is going to increase from about 40 to 80 gallons per minute to 40 to 100 gallons per minute. This is below design limits and it's also equivalent to what they operated with until about 1990. The temperature and pressure are also increasing, but remaining within the design limits. This is true for the piping and the containment isolation valves.

And we also note that this system steam generator blowdown system is monitored within the FAC program. And so we concluded that the power uprate would not effect the ability to remove impurities from the secondary system.

On the Chemical and volume control system there's several functions related to water inventory and water quality. The license told us about there is an expectation that there will be need for increase boration and also there is a possibility of increased crud buildup. These increases are within the design limits. The increases in temperature in the system are small and will not effect the operation of the heat exchanges, so therefore not the system in general. And so based on these small changes and all remaining within design, we just that acceptable.

Finally, paints and other organic materials. The plant was constructed prior to Regulatory Guide 1.54, which is our guidance now for the application of coatings. The coatings were applied according to Westinghouse and plant specifications. And since then the coating program has also been evaluated under the Generic Letter and license renewal processes. So we are focusing on changes in the coatings from the power uprate.

The license provided some temperature containment with pH, spray pH values and radiation dose values and compared that to the values at which those coating were qualified. And so those will all remain within the qualification parameters for normal operation design basis accidents and post-accident operations.

So on that basis we don't expect any effect on the adhesion or degradation of the coatings. Not that there isn't degradation, but the effect of the degradation on the plant and other debris is being evaluated under the Generic Letter 2004-02 process. And that includes the effect of power uprate.

Now there other organic materials in containment such as --

MEMBER WALLIS: Did anyone inspect the coatings at the plant?

MR. MAKER: Yes. There are coatings. There's a program for coatings.

MEMBER WALLIS: Are they in good shape? Are they all in good shape?

CHAIRMAN DENNING: Do you mean as part of power uprate and are you both in agreement here?

MEMBER SIEBER: No.

MEMBER WALLIS: Well, I think there was a license renewal that probably inspected the coatings. I was wondering what -- I mean, there's a statement that coatings do not detach from the substrate during a design basis LOCA. And I just wondered if their present state when you look at them indicates that they look like the kind of coatings that wouldn't detach. It's a very superficial inspection, but at least --

MR. WROBEL: George Wrobel from Ginna.

Yes, well we started as a result of Generic Letter 98-05 response, we did a pretty thorough walkdown of containment. And we did another one for IEEE for looking at the protective coatings on the liner. And then every year when we do our containment cleanliness walkdown we do an inspection of the coatings.

There is some coatings that are not there. I mean, you know some of the floor there's wear marks and things like that, but we haven't noticed any large layers of coatings being removed. And we did do an assessment of the adhesion of the coatings and there's not any large amounts of coatings that are coming off.

There are coatings that are off --

MEMBER WALLIS: Because coming off in a design basis LOCA is rather different. They're being bombarded --

MR. WROBEL: We didn't do it during a design basis LOCA, I'll give you that.

MEMBER WALLIS: So I just wonder what the basis was for asserting that they do not detach from the substrate during a design basis LOCA. Because we know that in some plants that they're bad enough that you may even see some of them detach without any LOCA at all.

MR. WROBEL: That's based on the qualification, the original qualification testing.

MEMBER WALLIS: The qualitification says they won't happen, that's right.

MR. WROBEL: And we have assessed the current coatings against the original coatings that were applied --

MEMBER WALLIS: Well, there's no instruction technique which sort of --

MR. WROBEL: Not during a LOCA, no.

MEMBER WALLIS: -- tests how well they're adhered now. No.

MEMBER MAYNARD: Have you ever done any pull test on it or anything? There are tests you can do for coatings to basically glue and see how much--

MR. WROBEL: We haven't done comprehensive pull tests, but we have walked down coatings and you can kind of tell if things are adhering. In fact, a few years ago we did do scrapings of the coatings to try to get them off because we want to assess them against -- you know, make sure they were still consistent with the original coating composition. And we actually had a lot of trouble getting coatings off most areas of the plant. Now, again, there were a few areas that was gone already, so we didn't get any coatings.

MEMBER MAYNARD: Yes. There are some things you can do besides just looking at that.

MR. WROBEL: Yes.

MEMBER MAYNARD: And it sounds like you have done some of those.

MR. WROBEL: A little bit. It's not a huge comprehensive program yet, but I think this 2004-02 is going to be bringing more.

MR. MAKER: Well, I'll finish up with the other organic materials, things like cable insulation that could generate hydrogen and other inorganic acids because of higher temperatures and radiation dose. And the increases will be insignificant. There won't be significant gas generation.

CHAIRMAN DENNING: Thank you.

MR. MAKER: Okay. You're welcome.

MR. MIRANDA: I'd like to introduce Raul Hernandez. He's from our Balance of Plant Branch. And he's going to be talking more in the systems area and the EPU effects and our evaluation of the EPU effect or EPU conditions on a number of the balance of plant systems.

MR. HERNANDEZ: My name is Raul Hernandez, like he said. And I'll be discussing the review of the balance of plant section.

Our review is based on Review Standard 001 Matrix 5. There's over 20 systems in Matrix 5. These systems can be summarized as internal hazards, fission product control, component cooling and decay heat removal, balance of plant system, waste management system, emergency diesel fuel oil storage and light loads. And also we review test consideration for certain balance of plant systems.

For the purpose of this presentation we are going to emphasize the spent fuel pool cooling, the service water system and the ultimate heat sink, the auxiliary feedwater system, the condensate and feedwater system. But you can ask questions of any system if you have them.

For the spent fuel pool system, the licensee performed a heat load analysis and determined that the heat load would not be exceeded for the spent fuel pool cooling system. And they will maintain administrative control to make sure of this. They will be delaying the full core upload until they have assurance that they have enough cooling capability.

The licensee has commit to make some material changes to the tech spec to reflect this new thermal analysis that they have performed.

During the evaluation --

MEMBER WALLIS: What is this alternate source?

MR. HERNANDEZ: What?

MEMBER WALLIS: What is the alternate source in the second bullet?

MR. HERNANDEZ: Yes. This is for the worst case scenario boil up rate. The licensee has a make up source with -- that is going to be higher that this worst case boil up rate. They have in addition to that an alternate make up water source for the spent fuel pool which has the capability of 50 gallons per minute. This is slightly below the worst case boil up rate of 52.8 gallons per minute. The licensee has done an evaluation and have determined that in the time that it would take for the boil up rate to drop to 50 or below gallons per minute, the spent fuel pool would have lost less than or almost 2 inches of water. The staff determined that based on all the conservatism in the calculations, that this was acceptable. And the licensee has committed to update the USR to include this justification.

MEMBER WALLIS: This alternate source is something that's installed and comes on automatically with some signal or something?

MR. HERNANDEZ: Well, for the worst case this is if they lose all cooling for the spent fuel pool, they have the capability of providing makeup water for the spent fuel pool from the condensate storage -- excuse me. Let me just make sure.

MEMBER WALLIS: So it requires some operator action? It requires some operator action?

MR. HERNANDEZ: Yes. Yes. It will take some operator action. It's not an automatic system.

The preferred one is the RWST --

MEMBER WALLIS: But the operator action is opening valve, it's not laying a line or something? It's not actually installing a hose or something? The hose is already there. It's just opening an valve?

MR. MIRANDA: A valve line.

MEMBER WALLIS: Right.

MR. HERNANDEZ: The alternate source is the CBCS.

MR. DUNNE: Yes. The alternate source is our charging system. The other thing is the boiler over which you're going to lose this 2 inches, it's on the order of 19 hours. So that's more -- well before that time we'd have alternate source water available.

MEMBER WALLIS: This isn't really an EPU issue anyway, is it?

MR. DUNNE: It basically changed because we did an more conservative analysis for EPU than we have presently. And the two inch number we gave the NRC was also a conservative analysis. We basically assumed that we instantaneously offload the entire core at the minimum time, that we instantaneously heat the pool to its limit at that point in time and then we instantaneously lose decay heat, and then we got a boil off. And so there's conservatism in the analysis.

MR. HERNANDEZ: Next we're going to be discussing the service water system and the alternate heat sink. For Ginna Lake Ontario is the alternate heat sink.

The service water system evaluation has determined that the system has enough capability to handle the decay heat at EPU conditions. Flow rates are capable to handle EPU during the safe shutdown and injection phase only one service water pump is required. But like for, like as I mention here, post-LOCA mitigation recirculation phase, two service water are required. The licensee has committed to revise the tech specs to include this into the tech specs.

And like I already mentioned, no modifications are required due to the EPU.

For the aux feedwater systems there's some -- over here that you see that the preferred flow -- that the preferred AFW required flow has increased 5 gallons per minute. There was some confusion in some statement on the application. We discussed this with the licensee and what they discussed before, that the required flow hasn't change, that is acceptable and that was their original intent.

CHAIRMAN DENNING: We talked before the break and since then I've had an epiphany and remembered where the numbers came from.

Basically Westinghouse for exit analysis basically asked for a minimum AFW flow rate and a maximum AFW flow rate to use. And for whichever analysis if it's conservative to use the minimum, they used the used the maximum if it's conservative to use the maximum, they used the maximum.

So right now the way AFW system is designed when it gets automatically initiated is a control valve that throttles back and will stop throttling once the AFW flow gets between a range of 200 to 230 gpm.

So previously we had always used 200 gpm as our minimum number and 230 gpm as the maximum.

For EPU, again this is one of those areas where our instrumentation people would like to have more margin for uncertainty analysis, we decided that we would increase the maximum number from 230 to 235. So for any analysis that Westinghouse did where they need to maximize AFW flow to a steam generation for a particular transient, they are now using a max flow of 235 gpm for any analysis. Where it's conservative to use minimum numbers, they're using the existing, they're using the 200 gpm number, which is the capability of the system.

So the reality is the way the table is in the submittal it's somewhat confusing to interpret and it does mean you need to increase AFW flow to 230 to 235 or a 5 gpm increase. We basically are saying that we are using a conservative up or down for max flow of 235 gpm in lieu of 230 gpm for the present licensing basis. So we've added some conservatism to our analysis of record.

MR. HERNANDEZ: For the standby AFW systems, the licensee has acknowledged that the required flow has increased. It's supposed to reach 35 gallons per minute.

The Staff finds this acceptable based on the testing that is going to be performed on the system. Part of the power uprate testing, they're going to perform a test to verify that the system can provide the required flow as it's supposed to.

For the condensate and feedwater system the Staff have determined that no safety challenges have been created. There are some major modifications to the system which includes a feedwater regulatory valve, feedwater pumps and the condensate booster pumps.

To decrease the severity of certain vents the licensee is performing some system tuning. The ones that we mention here is main feedwater pumps, suction pressure setpoint, main feedwater pump, NPSH calculator setpoint and delays have been added to the low pressure heater bypass value open circuit. Basically this modifications add to reduce the severity of a loss of condensate pump, loss of condensate booster pumps or heat or drain pump.

During power accession and during some limited transient, the licensee is going to monitoring the performance of the main feed system to verify their modeling of different areas and to verify the setpoints that they have used.

As a summary, the Balance of Plant Staff has determined that the EPU is acceptable with respect with the Balance of Plant area. This is based on the evaluations of the licensee's submittal and their results, the commitments that the licensee has agreed on and the results from the power ascension and transient testing program.

Any question?

MEMBER SIEBER: Thank you.

CHAIRMAN DENNING: Thank you very much.

Okay. Let's talk just a little bit about tomorrow, because I think we're done for the day, right?

MR. MIRANDA: Right. We are done for today.

CHAIRMAN DENNING: As far as tomorrow is concerned, my guess is that we probably will be finishing up an hour before the scheduled time, but it's a little bit hard to interpret now. With regards to what kinds of surprises we might have for you tomorrow and who you ought to have around, I think we ought to talk about that just a little bit.

It's conceivable that over the night we might decide we want to talk a little bit more about safety analysis. Do you think that's likely, Graham? I don't know. I don't know whether you're wondering what people should I have here tomorrow and is there anybody that you'd like to dismiss and send home and we could discuss now whether we think that we might miss them.

I mean, it's up to you. I don't know whether -- as far as you're concerned, I mean there's a lot of money involved in this whole thing and you might want to just keep them here just in case. But my guess is there's some set of your staff that could really go home, but I don't how to advise you.

MR. FINLEY: Right. And we'll be prepared to discuss further safety analysis questions if you have those. As far as our electrical folks and materials, we intended to send them home tonight.

CHAIRMAN DENNING: I see absolutely no problem with that.

MR. FINLEY: Okay. Then we're fine I think.

CHAIRMAN DENNING: Okay. You're fine? Okay. Very good.

Then did you have any other comments or questions?

MR. MIRANDA: No, I don't.

CHAIRMAN DENNING: No? Okay.

MR. MIRANDA: So similarly, you would like to have our Staff, our safety analysis staff here also?

CHAIRMAN DENNING: I think that would be a good idea. Because --

MR. MIRANDA: Just the reactor systems portion or the dose consequences people? Just the reason systems?

CHAIRMAN DENNING: Just the reactor systems people.

MR. MIRANDA: Okay.

CHAIRMAN DENNING: I think we're pretty comfortable with the dose.

MR. MIRANDA: Yes, dose came out pretty good.

MEMBER WALLIS: Your people in response to our questions earlier today in the reactor systems area, are they preparing anything that they might want to bring in as an illustration of an example of how thorough their investigation was or something? Or are they just leaving it open in case we might ask something? Are they preparing anything.

MR. FINLEY: No, they are not preparing anything.

MEMBER WALLIS: They're not preparing anything.

MR. MIRANDA: No.

MEMBER WALLIS: Sometimes that happens when we ask questions, they say oh I wished I'd actually been able to present something, and they --

CHAIRMAN DENNING: But I'm not suggesting that you now initiate --

MEMBER WALLIS: I'm not suggesting. I'm

just asking if -- I'm just asking if they had that on their agenda. I wasn't soliciting it. I was just curious if they --

MEMBER SIEBER: It might not be a bad idea, though, to pick some aspect of the review and go through it carefully with us to show what the basis is, what things you reviewed from the licensee and how you draw your conclusions, what kind of calculations if any do you make on your own as confirmatory. And a way to describe the basis for a conclusion that says everything is okay. I think if we just ran through that once, perhaps it would help us.

CHAIRMAN DENNING: But if you want to defer that until we meet again in a month, you can do that. It makes more sense than trying to --

MEMBER SIEBER: You probably couldn't put it together for tomorrow.

MR. MIRANDA: Yes. Basically what it would be is an ad hoc discussion --

MEMBER SIEBER: That wouldn't do.

CHAIRMAN DENNING: Okay. In that case we are adjourned until tomorrow.

(Whereupon, at 4:53 p.m. the Subcommittee was adjourned, to reconvene at 8:30 a.m. on March 16, 2006.)