Official Transcript of Proceedings ACRST-3189

NUCLEAR REGULATORY COMMISSION

ORIGINAL

Title: Advisory Committee on Reactor Safeguards
490th Meeting - OPEN SESSION

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

Docket Number: (not applicable)

Location: Rockville, Maryland

Date: Thursday, March 7, 2002

Work Order No.: NRC-272 Pages 1-38/50-97/118-271

[Closed pps. 39-49/98-117]

NEAL R. GROSS AND CO., INC.
Court Reporters and Transcribers
1323 Rhode Island Avenue, N.W.
Washington, D.C. 20005
(202) 234-4433

TROY

DISCLAIMER

UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

March 7, 2002

The contents of this transcript of the proceedings of the United States Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected, and edited, and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

490TH MEETING

+ + + + +

THURSDAY,

MARCH 7, 2002

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

The committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., George E. Apostolakis, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

GEORGE E. APOSTOLAKIS	Chairman
MARIO V. BONACA	Vice Chairman
F. PETER FORD	Member
THOMAS S. KRESS	Member
DANA A. POWERS	Member
WILLIAM J. SHACK	Member
JOHN D. SIEBER	Member

ACRS STAFF PRESENT:

MAGGALEAN W. WESTON

PAUL A. BOEHNERT

SAM DURAISWAMY

SHER BAHADUR

CAROL A. HARRIS

JOHN T. LARKINS

MICHAEL T. MARKLEY

I N D E X

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

(8:33 a.m.)

CHAIRMAN APOSTOLAKIS: The meeting will now come to order.

This is the first day of the 490th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the committee will consider the following: Clinton Nuclear Power Station Unit One Core Power Uprate; Proposed NEI 00-04, "Option 2 Implementation Guideline," for Risk-Informing the Special Treatment Requirements of 10 CFR Part 50; Arkansas Nuclear One, Unit 2 Core Power Uprate; and Proposed ACRS Reports.

Portions of the meeting may be closed to discuss GE Nuclear Energy and Westinghouse proprietary information. This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the designated federal official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

A transcript of portions of the meeting is being kept, and it is requested that the speakers use

one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

The first item on the agenda is the Clinton Nuclear Power Station Core Power Uprate. Dr. Powers is the cognizant member. Please.

MEMBER POWERS: A fact. Thank you, Mr. Chairman.

We're going to discuss the Clinton power uprate with both the applicant and the staff. There is going to be episodic interruptions in the meeting in order to close it to handle proprietary data, and I'll beg the Chairman's indulgence for any extension of the schedule that occurs because of that.

The Clinton power uprate is for BWR6. We've certainly heard power uprates before, but this is the first BWR6 we'll hear about. The uprate is significant. It's overall 20 percent. It's taking place, however, in two steps -- a seven percent, a 13 percent. It also involves a change in the fuel.

There was a subcommittee meeting dealing with this subject, and some draft positions have been taken -- developed by that subcommittee. What the subcommittee found was that the licensee is, of course, pursuing this power uprate under what has come

to be called the ELTR1 and ELTR2 methodologies that the staff have approved.

But, in fact, this is a constant power -- a constant pressure power uprate, and the details of that methodology are still being reviewed by the staff. As a consequence, the applicant will take certain exceptions to the ELTR1 and ELTR2 methodologies, and I encourage the committee to pay close attention to these exceptions.

At least one of the exceptions is the familiar large transient testing that we've discussed before. I'm disappointed Mr. Rosen is not here to hear the discussion on that particular exception, but there are other exceptions having to do with the analyses. And I, again, suggest the committee pay close attention to it.

The use of a constant pressure power uprate converts the problem of power uprate from one that's primarily from a hydraulic issue to one that's much more neutronic flavor. There are, however, some thermal hydraulic issues that you have to deal with, even for a constant power -- constant pressure power uprate, because you've got to have increased flow someplace in this system.

And, of course, that flow takes -- those

increases in flow take place in the feedwater and the steam flow, and that raises some issues of flow-assisted corrosion in some of the piping systems. And, indeed, we have issues of flow-assisted corrosion in this particular unit, and I encourage the committee to pay close attention to those particular issues.

The applicant and the staff, of course, think they have this issue well under control through a combination of modeling and monitoring. There is a history in the nuclear industry of these methods not working, with some substantial consequences. So it's worth paying attention to that.

With that introduction, I will turn to Mr. Bill Bohlke from the applicant to begin the discussion of their proposed extended power uprate for the Clinton Power Station Unit Number 1.

MR. BOHLKE: Thank you. Good morning, Mr. Chairman, and members of the committee. I'm Bill Bohlke, Senior Vice President of Nuclear Services for Exelon Generation.

I just thought I'd spend a minute or so giving you the background on AmerGen, which is a company that you may not be particularly familiar with.

MEMBER POWERS: True.

increases in flow take place in the feedwater and the steam flow, and that raises some issues of flow-assisted corrosion in some of the piping systems. And, indeed, we have issues of flow-assisted corrosion in this particular unit, and I encourage the committee to pay close attention to those particular issues.

The applicant and the staff, of course, think they have this issue well under control through a combination of modeling and monitoring. There is a history in the nuclear industry of these methods not working, with some substantial consequences. So it's worth paying attention to that.

With that introduction, I will turn to Mr. Bill Bohlke from the applicant to begin the discussion of their proposed extended power uprate for the Clinton Power Station Unit Number 1.

MR. BOHLKE: Thank you. Good morning, Mr. Chairman, and members of the committee. I'm Bill Bohlke, Senior Vice President of Nuclear Services for Exelon Generation.

I just thought I'd spend a minute or so giving you the background on AmerGen, which is a company that you may not be particularly familiar with.

MEMBER POWERS: True.

MR. BOHLKE: AmerGen is co-owned by British Energy and Exelon. When it was recently formed, it was co-owned by British Energy and PECO. But with the Comed and PECO merger, Exelon assumed the original PECO share. So that's the ownership, and AmerGen is, in fact, the licensee.

Operationally, Clinton is part of the Midwest Regional Operating Group, just as Oyster Creek and TMI are parts of the Mid-Atlantic Regional Operating Group. What that means is we share a Chief Nuclear Officer, who last week became Jack Scolds who succeeded Oliver Kingsley who is now our head of generation.

And specifically, in the Midwest, the executive direction and corporate oversight for the Clinton station is executed by the Midwest ROG out of Warrenville, Illinois.

The staffing for Clinton, similar to the staffing for the other two AmerGen units, is a combination of Exelon employees and AmerGen employees. Those AmerGen employees have various heritages depending upon the utility from which they came. In fact, the station leadership at Clinton currently consists of a site vice president, plant manager, site engineering director, site operations director, and

training manager, all of whom are Exelon Nuclear employees.

So we also use Exelon policies, Exelon programs and processes, down to a level where we want station or unit individuality as opposed to common or standardized processes, so that many of the organizational structure and management approaches for Clinton are the Exelon approaches. And the technical approaches, including the technical approaches embodied in this request for power increase, is derived from the Exelon approach.

Specifically, this is a fourth boiling water reactor station in Illinois that we've subjected to this. LaSalle was the first one, and you reviewed that in either late '99 or early 2000. And then, of course, last fall you heard the presentation on the Dresden and Quad Cities power uprates.

Dresden 2, in fact, has been uprated and is operating at 912 megawatts, which is its generator limit. That startup and testing went extremely smoothly. Quad Cities 2 has just completed its outage and is at about 40 percent power this morning going -- undergoing its testing. And so far so good on that one also. So Clinton will be the fourth in a series of that.

To try to achieve continuity, the project manager for the Clinton power uprate was, in fact, project manager for the LaSalle power uprate. Some of the technical people are the same. You probably recognize some of them. So what we do is we allow ourselves to benefit from the lessons learned and move it on down the line, so that every project has a benefit of its predecessor.

And so what we'll see is, when we do the startup testing for Clinton, it's subject to the granting of the power uprate license. We'll have startup testing personnel who have worked at Dresden or Quad or LaSalle previously, so that we'll have that lessons learned. We think that's a real strength of the program.

So that's the extent of my introductory remarks. I did want to set the stage for that, and now let me introduce Dale Spencer, who is the Project Manager for the Clinton extended power uprate.

Thank you.

MEMBER POWERS: Mr. Bohlke, I appreciate your giving us that introduction to this company. We see the name all the time, but we really don't know too much about it.

MR. BOHLKE: You're quite welcome.

MR. SPENCER: Thank you, Bill. Good morning.

Dale Spencer, Exelon Nuclear, Project Manager for the Clinton Unit 1 extended power uprate. Over the next hour, our experts will be providing a summary of the EPU project, including the modifications, the analyses performed, and our plans for implementation. Presentation material has been chosen based on the agenda that been provided to us by the ACRS.

As we discussed previously, portions of our material are proprietary to the General Electric Company, and we'll ask that a portion of the meeting be closed. We have grouped the information that's proprietary together, so we can minimize interruptions.

MEMBER POWERS: If you will just indicate to me when you need to close it --

MR. SPENCER: Yes, sir, we will.

MEMBER POWERS: -- we will go through whatever machinations we have to.

MR. SPENCER: Yes. Yes, sir, we will.

As an introduction, I want to first spend a few minutes and provide a summary of the overall EPU project, and then I'll follow by an overview of the

modifications and analyses that we have performed.

We're requesting a license for a 20 percent increase in reactor power. We use the GE standard EPU process as the guide for our analyses and the schedule. These GE processes, as you know, have been used for a number of extended and stretch power uprates in the industry, both domestically and abroad.

We'll be performing modifications to the plant to facilitate power ascension, and I'll cover these in more detail in a couple of slides. And these modifications will be installed between now and early 2004.

Of these modifications, we'll show that we're making relatively few changes to the operation of safety systems. Our plans are to implement the power ascension in two steps. The first step will be -- take place when we start up this May after our refueling outage.

MEMBER POWERS: Let me ask a question. You make a point that you're making relatively few changes to the safety system. Am I supposed to derive comfort from that?

MR. SPENCER: Yes.

MEMBER POWERS: Why?

MR. SPENCER: Essentially, our analyses

have shown that the modifications to the plant and the limits to the plant post uprate will be on the BOP side. Our changes are essentially, as I'll get into in the next slide, the nuclear instrumentation that we're going into. Other plants have gotten into modifications in other areas, and with the BWR6 we have found that this is not the need. And this is a plus.

MEMBER POWERS: I mean, what you're essentially saying is that your safety systems have enough margin to handle the additional 20 percent.

MR. SPENCER: Absolutely.

MEMBER POWERS: Okay. But, clearly, you're reducing the margins you have in those systems.

MR. SPENCER: Yes, absolutely.

MEMBER POWERS: And somehow that's acceptable.

MR. SPENCER: Yes, it is.

We talked about our first step for our license, for our power ascension in May of this year. And the second step of our power ascension will take place after our ninth outage, and that's scheduled for early 2004.

On the next slide is a simple graph of the power-to-flow map at EPU conditions. For clarity, in

the upper right-hand corner, the gold area, is the EPU operating region. Simply, as we stated in the subcommittee, we're increasing power along the previously licensed MELLLA flow control line.

Other plants that have licensed the extended power uprate have licensed the MELLLA as part of their EPU process. In the case of Clinton, this has already been licensed, so we are not changing any of the flow control line in our power uprate.

MEMBER KRESS: The axis is 100 percent of what? The core flow is for what -- percent of what? I mean, core power -- core flow. Is that 100 percent of what?

MEMBER POWERS: It's both. I mean, the question applies to both.

MEMBER KRESS: Yes. What are the units on your --

MR. SPENCER: The axis on the power is the 100 percent of uprated reactor power, in the top of the graph right here, the 3473.

MEMBER KRESS: Okay. So that's the full new uprated power.

MR. SPENCER: Yes, sir.

MEMBER KRESS: What's the one on the bottom?

MR. SPENCER: The one on the bottom is the core flow. The core flow is not changing. The core flow is based on the capability of the recirc system. So we will need to --

MEMBER KRESS: So when you go up to 110 percent almost there, what does that mean?

MR. SPENCER: I'm sorry. Which --

MEMBER KRESS: Well, at the --

MR. SPENCER: Are you looking right in here?

MEMBER KRESS: No. Looking at the yellow part.

MEMBER SHACK: The X axis.

MEMBER KRESS: The X axis, and looking there. That's like 109 percent or something.

MR. SPENCER: Oh. This is the ICF, the increased core flow region. This is previously licensed on --

MEMBER KRESS: This is the previously licensed core flow.

MR. SPENCER: Yes, sir.

MEMBER KRESS: There's a maximum core flow in your license?

MR. SPENCER: Yes, sir.

MEMBER KRESS: I see.

MR. SPENCER: This was our license as we have it right now, and it's in the same X axis, if you can see on the graph.

MEMBER KRESS: The dotted line is --

MR. SPENCER: Yes.

MEMBER KRESS: It goes all the way up to 108 percent?

MR. SPENCER: In core flow, that's correct.

MEMBER KRESS: Okay.

MR. SPENCER: You know, that's actually 107, I believe.

MEMBER KRESS: Is there any reason why you can't use that little triangle up at the top?

MR. SPENCER: That's basically the capability of the recirc system.

MEMBER KRESS: Okay. You would have to change out your jet pumps to --

MR. SPENCER: That would be a pretty significant change. Yes, sir, that's correct.

On the next slide, I just have a brief summary of the change in plant conditions graphically. Briefly, the increase in steam flow is accomplished by replacement of the high pressure turbine, and, thus, no changes in the reactor steam dome pressure is

needed. And we discussed this at the opening of the meeting.

I'd like to spend just a few minutes going over some of the modifications we'll be performing. As we stated in our uprate safety analysis report, no safety-related hardware changes will be required to implement the EPU at Clinton.

Upon issuance of the revised operating license, we're going to perform changes to nuclear instrumentation which will allow us to increase our output. These set point changes include the APRM, the flow bias, both the SCRAM and the rod block, the main steam line group 1 isolation, the control and stop valve and recirc pump trip bypasses, and the low power and high power set points on the control rod block pattern controller.

Proceeding to the modifications we'll be performing on the BOP side of the plant, as I talked previously, we're going to be implementing our power ascension in two steps. During our upcoming refueling outage, we'll be replacing the high pressure turbine. We'll be replacing the main power transformers, as well as associated changes to the isolated phase bus duct configuration and cooling.

The main generator hydrogen coolers will

be replaced, and we'll increase the hydrogen pressure in the generator from the current 60 to 75 pounds. The exciter anode transformer will be replaced, and we'll be upgrading five supports associated with the feedwater system, all of which will allow us to achieve the additional 80 plus megawatts for the next operating cycle.

MEMBER POWERS: When you make changes in your hydrogen system, changes in transformers, how do you affect the risk of fire-initiated accidents in your plant?

MR. SPENCER: The fire-initiated accidents were analyzed, and we are going to be discussing some of the risk from all of the risk factors a little bit later in the presentation. I believe Bill Burchill is going to get into that at some later time. Can we discuss that then, or would you like to --

MEMBER POWERS: That would be fine.

MR. SPENCER: Okay. And that is part of our presentation material at a later time.

Proceeding on, to ensure we get the full potential from our uprate, we'll be performing additional modifications to -- and I call them BOP efficiency improvements in the future. These are targeted to be installed either online or during the

ninth refueling outage to facilitate future power increases. And since these are a little bit down the road, these modifications are in the scoping stage, and I'm just going to provide a conceptual overview right now.

Improvements will be made to the condenser to perform at a higher efficiency. Improvements will be made to allow condensate polisher stop rate and balanced flow configuration at the higher condensate flows we expected. Moisture separator reheat Chevrons will be replaced to improve the MSR, and that goes forth to the plant efficiency.

Changes will be made to the breakers, conductors, relay schemes associated with the switchyard to allow the increased megawatts electric and MVA output of the plant. Improvements to the exciter plan, which will allow the plant to run at the full capability of the generator. And we do foresee future improvements in the cooling capability of the bus duct cooling.

MEMBER FORD: Can you just elaborate on the --

CHAIRMAN APOSTOLAKIS: Microphone.

MEMBER FORD: Could you elaborate on the main condenser improvements? What are they, and why

are they being made?

MR. SPENCER: Okay. These are changes that we're going to make in our ninth refueling outage, which is currently scheduled for early 2004. And I'll preface it with the fact that we're doing conceptual studies, and this is not finalized at this time.

The most -- I'll say the most front runners we have right now are changes in online cleaning system and making sure that we're using the condenser to its full capability, not having any air entrained in the condenser. Essentially, making sure we run it at its highest efficiency.

MEMBER FORD: With the increased steam flow, are you not expecting vibration problems in the condenser --

MR. SPENCER: We have --

MEMBER FORD: -- with the current design?

MR. SPENCER: We have performed analyses of the condenser tubes. We are -- obviously, we are putting more steam flow in. We have analyzed this to be acceptable.

MEMBER FORD: Was there any basis for saying that? I mean, is it based on analysis, or other plants' experience? I guess these are GE

turbines, and there's plenty of other GE turbines with the same design out there.

MR. SPENCER: Sure. And --

MEMBER FORD: Are there any with the same flow rate, the increased flow rates, to draw on?

MR. SPENCER: For our analysis, we used a specialty vendor who does this kind of work in several locations, and every condenser is just a little bit different. There is a mix between analytical techniques and actual industry experience that he factors into his work. We also do routinely monitor the performance and perform inspections on equipment, even down to the condenser stage in our plant. And that's an ongoing type evaluation.

We'll continue to do these inspections even post uprate and continually monitor the performance of all of our plant equipment.

MEMBER FORD: Okay. So these improvements aren't necessarily related to increased steam flow, the EPU. It's just -- you just want to increase the efficiency. It's got nothing at all to do with -- it's not driven by the fact that you've got increased steam flow.

MR. SPENCER: At the current efficiency of the condenser, it's not -- we're not going to be able

to get a whole lot extra out of the condenser, unless we do something to it. So it is a little bit of both.

MEMBER FORD: Okay. Thank you.

MR. SPENCER: So I'd like to change the focus just a little bit here, and I want to concentrate on some of the analyses and evaluations that we've performed in support of EPU. Listed on the slide are the specific subjects for which we have prepared presentation material and our experts will be talking.

As I stated previously, we have chosen the subjects based on the agenda provided us to the ACRS. So at this time, I'd like to introduce Fran Bolger of General Electric, who will discuss the core and fuels analyses.

MR. BOLGER: Morning. I'd like to discuss some of the details of the core fuel analysis that have been performed. As part of the power uprate, there was an equilibrium core analysis, which did demonstrate a full extended power uprate power, that the core was able to provide the desired energy and have adequate thermal margins.

I'd like to discuss some of the details of the actual core design which was performed for Cycle 9. Cycle 9 is the first step in the two-step

process that was previously described.

Next slide.

To the left, there is a -- this is a picture of the core design for Cycle 9. What you see are the color -- these shaded bundles are the fresh core, the fresh bundles in the core. Up here on the top you see the locations. And the I and J location, we'll be talking a little bit about those.

Looking at the core design map, you'll notice a value in the center of each square, and that's the bundle exposure, megawatt days per shore ton. The zero indicates that it's a fresh bundle.

The value here on the bottom, which you can't see very well, that correlates to a bundle type used in the simulator. This core was analyzed with the PANACEA 3D simulator, and that relates to this value here called IAT down here on the bottom.

If you look on the bottom, you'll see the bundles that are loaded in this core. The top bundle is a two cycle depleted bundle, which is a GE10 type fuel, which is eight by eight design. The next two bundles are one cycle depleted bundles, which are GE14 type. And the last two are the fresh fuel, which are also GE14 type.

If you look, you'll -- if you look on this

bundle name, you'll see these numbers here. These indicate what the bundle average enrichment is for the bundle. There is 268 fresh bundles being loaded, which is a fairly large bag size. These values here are the batch average exposures for the fresh bundles at beginning of cycle.

Over here on the right is a batch average radial peaking. These values are actually rounded two points past the decimal.

What I'd like to do now is talk a little bit about -- a question?

VICE CHAIRMAN BONACA: Just G14, what is it, a 10 by 10, 11 by 11?

MR. BOLGER: G14 is a 10 by 10 design.

VICE CHAIRMAN BONACA: 10 by 10.

MR. BOLGER: I'd like to talk now about some of the results -- the key results in the core design, cycle design analysis. Over here on the right you see this column here, which is the cycle exposure, and this is measured in megawatt days per shore ton. And you see the core is designed with various steps through the cycle, and each one of these steps has a different control rod pattern.

For example, you see here this is the control rod pattern at the beginning of cycle. You

see the rod positions shown here on the map. The red boxes are actually the controlled cell locations.

The next column is the critical Eiger value. When a core is designed, a target critical Eiger value is developed through the cycle, and this target is developed based on previous cycle experience with that plant. It's based on other plants with a similar fuel design and size, and also based on the fuel design characteristics.

The next column is a -- is for this depletion, the core flow as a function of exposure. If you look at the core flow, you'll notice that some of the core flow values are below what was on that top corner of the power flow map previously shown. The minimum core flow at full EPU is 99 percent, but this is lower than that because this depletion is actually about 90 percent of full EPU power.

The next column is the ratio of the operating limit, minimum critical power ratio -- I'll call it MCPR -- to the calculated MCPR. When a core is designed, you try to achieve sufficient MCPR margin so that the core will operate when it is actually monitored in the plant. You design the core typically with about seven percent MCPR margin.

In this case, this core -- the maximum is

about .9, and so there is a little bit of margin relative to what typically would be the target of about .93. So there is actually a little bit additional margin, and this core could probably operate at a little bit higher power.

These values in parentheses over on the right of the MCPR margin is the location of the limiting bundle, and those values correspond to these locations on this I and J location over here on the core map. And you see the limiting location does move around in the core.

The next column is the ratio of the calculated peak rod LHGR relative over the LHGR limit. And in this case these locations are the I and J location as described over here, but also this right-most is the axial location. The core is designed with 25 axial nodes. So, for example, you see over here node 4 is toward the bottom corner of the core.

MEMBER POWERS: You said that the core was designed with 25 axial nodes. Do you really mean it was analyzed with 25 axial nodes?

MR. BOLGER: Yes, that's correct. The core was analyzed with 25 axial nodes.

The right -- this column here is the ratio of the average planar linear heat generation rate to

the average planar linear heat generation rate limit. And this is where the LOCA limits are factored in.

The right-most column is the core average axial power shape peak value, and what you see here is the value for the core average peak and the node. For example, node 10 is toward the center of the core. You'll notice that the core peak for most of the time in the cycle is toward the bottom of the core. And as you get down toward the end of the cycle, the power shade moves up to the top.

The BWR will naturally try to peak to the bottom because of the voids -- the voids in the core. The core -- this core, as shown, has -- provides the desired energy and has adequate MCPR and LHGR margin.

Next slide, please.

What I'm showing here is -- this is the same core design as you saw on the previous slide at beginning of cycle. This is just to show what you would get if you depleted the same core with the same control rod patterns at a lower reactor power -- in this case, about a seven percent lower reactor power.

You'll see, if you compare the two pages, that the critical Eiger value is slightly higher, because it's at a lower void fraction. The thermal limits are lower because -- obviously, because the

core is at a lower core thermal power.

And you'll also see that the power shape has shifted up somewhat, because the core is at a higher void fraction. That allows the power shape to move somewhat.

If this were an actual design in this case, there is more than adequate MCPR and LHGR margin. So you would -- the designer would try to take advantage of that additional margin. And we'd try to reduce bundles. We would try to move some of the bundles towards the center to try and improve the efficiency of the core. The designer might try to simplify the operating rod patterns to give more flexibility to the site.

So the designer will actually try to target the same margins to limits at the power level that it is being designed to.

Next slide, please.

MEMBER POWERS: Might I ask you one question on this? Your axial power peak moves fairly continuously through this. But there's a discontinuity in the node where you have your axial peak power. That occurs around an exposure of 11,500. Why does that discontinuity occur?

MR. BOLGER: Right here you see the power

shape moving -- moves -- starts moving up to the top. You'll also -- I can't tell you exactly, but you'll notice that the actual peak is -- the value of the peak is not very different. It could be that the power shapes are -- have a double peak or a fairly flat distribution, and just a very small variation in the power shape will shift it up to the top.

MEMBER POWERS: So this is more a numerical thing than it is --

MR. BOLGER: Yes.

MEMBER POWERS: -- a real discontinuity in the core performance.

MR. BOLGER: Yes.

Next slide.

In summary, the equilibrium core design that was analyzed for the EPU, and also the Cycle 9 design, has adequate margin.

Any questions? I'd like to -- the next presenter is Eric Schweitzer from AmerGen, who will present the containment analysis.

MEMBER POWERS: Maybe before you depart, I'll just ask you one question. The fuel exposures that you've shown in these two analyses are relatively modest. If I ask you about Cycles 10, 11, and 12, what kinds of fuel exposures do you anticipate taking

fuel to?

MR. BOLGER: You know, I don't -- I can just answer you generally.

MEMBER POWERS: Yes, a general answer is fine.

MR. BOLGER: You know, the fact that the batch size is fairly large means that the two cycle depleted bundles are -- it's not a full batch, and it's -- you wouldn't expect it to go to a three cycle depleted bundle. So the fuel will be depleted -- will be discharged after its second cycle. And the two cycle depleted bundles are primarily on the periphery.

So from a batch average standpoint, the batch has not a significantly different batch discharge than you would have if it were depleted at the current rate of power, just because the batch size would be lower and it would be possible to have a larger percentage of the batch loaded in the internal part of the core on the -- on its third cycle.

MEMBER POWERS: Can you give me a number?

MR. BOLGER: I don't have the value with me.

MEMBER POWERS: It sounds like you're going to discharge something a little over 30.

MR. BOLGER: I have a picture of the end

of cycle exposure map. It may be around slide 30 or so of the backups. Actually, you're interested more on the -- even the further on cycles.

MEMBER POWERS: I'm really interested in the --

MR. BOHLKE: Dr. Powers, let me see if I can -- if I recall correctly -- this is Bill Bohlke from Exelon. We won't have any burnups over 50,000 megawatt days per ton.

MEMBER POWERS: That's what it sounded like. Thank you. That's all the more precision I needed.

VICE CHAIRMAN BONACA: Just have a question regarding the cycle length. What is the cycle length of Cycle 9?

MR. BOLGER: The cycle length for Cycle 9 is a 21-month cycle.

VICE CHAIRMAN BONACA: And the following cycles, are they planning the same cycle length or --

MR. BOLGER: Maybe Exelon would like to discuss that.

MR. SPENCER: Future cycle lengths.

MR. SCHWEITZER: Your question was, what is the future cycle lengths?

VICE CHAIRMAN BONACA: Yes. Are you going

to stay at a 21-month cycle or --

MR. SCHWEITZER: Exelon does plan to transition to 24-month cycles, and there will be a future license amendment submittal for that.

VICE CHAIRMAN BONACA: Any idea now how that would change some of this neutronics here? What you just showed us?

MR. BOLGER: With -- go back to the previous slide. There is a -- for a 24-month cycle, there is a little margin for a higher enrichment. These bundles have not been designed to the maximum enrichment capability. So they can probably go to about the 415 level, and that will provide some additional energy for a 24-month cycle.

There is a benefit in having higher enrichment bundles in preceding cycles. They will carry more of the load as they get down into further cycles. So as you have higher enrichment transitioning, that will help you to create such a core design. And there is still a little bit of room to add a little more fuel, so it'll be challenging but the capability exists to do that.

VICE CHAIRMAN BONACA: Thank you.

MR. SCHWEITZER: My name is Eric Schweitzer from AmerGen, and I'd like to present the

Clinton MARK III containment analysis.

To evaluate the containment for extended power uprate, we followed the established method for containment analysis in ELTR1. The limiting events that were analyzed were the main steam line break, the recirculation suction line break, and the alternate shutdown cooling.

The next slide shows a summary of the results. This table shows the drywell and containment pressures and temperatures and the suppression pool temperature following the analyzed events. The first column of values on the left are the original analysis in the Clinton updated safety analysis report.

The second column of values are the comparison benchmark cases, which used the EPU methods with the original licensed power. The third column of values are the EPU results, and the last column shows the design basis.

Comparing the first and second columns shows the effect of the change in methodology. And comparing the second and third columns shows the effect of EPU, which is relatively minor with no vessel pressure change. Comparing the third and fourth columns shows the margins to the limits.

I'd like to point out that all remain

below the design limit with the exception of the drywell temperature. This value is above the design temperature of 330 degrees for less than .5 seconds. This has been evaluated as acceptable, because there is insufficient time to heat up the structure.

In conclusion, these results show acceptable performance for the containment in EPU.

MEMBER FORD: Could I ask a question? This is more for clarification. This seems fine, assuming that a containment maintains its original integrity. Now, I'm out of my depth here, but that's a big assumption, isn't it? That the containment maintains its original design integrity. Could you not have degradation of that integrity?

MR. SCHWEITZER: The containment is tested on a periodic basis, leak rate tested, and so it's maintained.

MEMBER FORD: So corrosion of rebar, for instance, that would be detected?

MR. SCHWEITZER: The leakage would definitely be detected, if that would cause any leakage, but the strength of the materials would not be expected to be changed outside its design margins.

MEMBER FORD: I know this is a topic that can be -- probably go into the -- a revised version of

GALL. But you're taking as right that the monitoring programs you have regarding the containment integrity are adequate.

MR. BOHLKE: Dr. Kress, let me -- excuse me. Dr. Ford, let me answer that. First of all, it's a steel containment.

MEMBER FORD: It's a steel containment.

MR. BOHLKE: And it's accessible. It's go ta shield going around it, so it's accessible for inspections and it does have the periodic leak rate test --

MEMBER FORD: So it's rather like Oyster Creek.

MR. BOHLKE: -- of the penetrations and the shell as a whole. So it's pretty robust, and it's pretty inspectable. We don't -- we have been doing containment ISI inspections on other plants in the fleet, and the extent of corrosion that we found after as much as 30 years of operation at Dresden and Quad Cities, for example, is pretty minimal. But, in fact, there is an inspection program as part of our requirements.

MEMBER FORD: The reason why I bring up the question is I never hear this topic mentioned, and yet I remember when I was employed by General Electric

that we were concerned about corrosion at Oyster Creek of the containment.

MR. BOHLKE: That's right. Exactly.

MEMBER FORD: And I have never heard anything along these lines mentioned since, and this is why I just bring the question up. As I say, it's more for my information. Are we kind of opening up a potential there for --

MR. BOHLKE: No. We think we're okay because we have a program which specifically focuses on that.

MEMBER FORD: Fine. Okay. Good.

MEMBER POWERS: I'm a little surprised that the applicant didn't bring to your attention that in establishing these limits that they take a certain amount of corrosion and degradation into account. I mean, there is a margin built into them for those reasons.

MEMBER FORD: Yes. A concern -- my concern is that whenever you look at these corrosion allowances they are almost going to be picked out of the air.

MEMBER POWERS: They are, and they are minuscule compared to what you saw at Oyster Creek.

MEMBER FORD: Correct. Correct.

MR. BYAM: Good morning. I'm Tim Byam with AmerGen. The next part of our presentation will address the exceptions that we've taken to the requirements specified in the extended power uprate licensing topical reports. That is, ELTR1 and ELTR2.

This portion of our presentation does contain General Electric company proprietary information, and we, therefore, ask that the meeting be closed at this point.

MEMBER POWERS: Okay. There will be a little interruption while we go through our steps here.

MR. STROMQUIST: This is Eric Stromquist from General Electric. I'd kindly ask that Mr. Wilson, Mr. Huff, and Mr. Moss leave.

MEMBER POWERS: You will switch to --

CHAIRMAN APOSTOLAKIS: You have to speak in the microphone.

MR. STROMQUIST: I'm sorry.

MEMBER POWERS: I don't know for this step, but we need to -- no, I don't think this is -- we should be switching at this point.

MR. STROMQUIST: This is Eric Stromquist with General Electric. All persons are acceptable in the room now.

MEMBER POWERS: Thank you.

(Whereupon, the proceedings went immediately into Closed Session.)

CHAIRMAN APOSTOLAKIS: Okay. Proceed.

MR. BYAM: Kent Scott will now continue with our presentation on the anticipated transient without SCRAM event response.

MR. SCOTT: Thanks, Tim.

Now I would like to discuss the response of the plant to an ATWS at uprated conditions. First, we found our response as operators to an ATWS remains unchanged. For example, when we lower reactor water level to reduce subcooling and trip the reactor recirculation pumps, we find the plant operating at the same power-to-flow conditions as pre-EPU.

This is due to the fact that the plant is currently licensed and operating under the maximum extended operating domain analysis. This is the MELLLA analysis with increased core flow that Dale spoke of earlier.

Since we already operate at these extended load lines, the plant reacts the same, simply moving down the existing load line on recirculation pump trips. Also, the symptoms we must observe as operators to detect an ATWS remains unchanged.

And, finally, our actions to mitigate an ATWS remain unchanged for controlling reactor power, reactor level, and reactor pressure.

MEMBER KRESS: But do you have to change how far you lower the water level into the core?

MR. SCOTT: No. We haven't changed -- we still lower level to the same values. We train on the same bands that we lowered the level to reduce subcooling. So that did not change at all.

VICE CHAIRMAN BONACA: The time for you to take action, however, has been reduced, right?

MR. SCOTT: And the analysis that Bill Burchill is going to talk about a little bit later about probabilistic risk assessment talks about those times. Those times are well within the capabilities of the operators to perform. The sequence of the actions we take are the same. The required times do reduce, but they are well within the capabilities of the operators. We're trained to do that, and I fully expect everybody to be --

VICE CHAIRMAN BONACA: Could you tell me what the times are? I mean, just for information.

MR. SCOTT: And Bill may be able to help me out a little bit with those times. I could tell you on the order, but I'd rather Bill tell you some particulars with that. Bill?

MR. BURCHILL: This is Bill Burchill with Exelon. The realistic analysis indicates that with --

I think it's with one slick pump the time is reduced from nine minutes to six minutes, and with two it's from 12 to nine minutes. And those times, as you recognize, are well beyond the licensing calculation, which assumes the times are on the order of a couple of minutes.

MR. SCOTT: Right. And my experience with initiating standby liquid control in an ATWS situation -- the times that Bill is talking about are an eternity for operators to get those actions performed.

MR. BURCHILL: Yes. This is Bill Burchill again. Again, the operator, of course, operates off of symptoms. You know, the response is specifically to the symptom, and, you know, the time is probably not in their mind at the moment when they're doing that. They're reacting to a symptom and taking action.

VICE CHAIRMAN BONACA: Yes. But, I mean, time available is important to determine whether they will take the action within a certain time.

Now, you mentioned something about two minutes. That's the design basis analysis rather than the -- so these values you gave us, nine minutes versus six, are a best estimate?

MR. SCOTT: Those are the probabilistic

risk assessment values, realistic analyses.

MR. BURCHILL: Right. Right. Dr. Bonaca, those are based on map runs specifically to look at the time available.

VICE CHAIRMAN BONACA: Okay. But your ATWS analysis that you have docketed with the NRC has different values.

MR. BURCHILL: Those are the licensing analysis. You're correct.

VICE CHAIRMAN BONACA: And two minutes are the reduced times for this design, or the previous --

MR. BURCHILL: Two minutes are the design.

VICE CHAIRMAN BONACA: And before it used to be three? Two? Two. So --

MR. BURCHILL: Yes, it's the same.

VICE CHAIRMAN BONACA: Why would it be the same?

MR. BURCHILL: I'm sorry. I didn't understand.

VICE CHAIRMAN BONACA: I said, why would it be the same time?

MR. BURCHILL: Because it's already a bounding time. It's already well within what we consider as a realistic evaluation of the time available.

VICE CHAIRMAN BONACA: I mean, as a number that comes out of an analysis, which is a bounding analysis, I would have expected to see a change in that time, too, with respect --

MR. PAPPONE: Yes. This is Dan Pappone, GE. The two minutes is actually an input assumption into the analysis. And, again, that's based on -- that's based on the knowledge that the operators are going to be working off of the symptoms, performing the same actions based on the same symptoms that are occurring actually a little faster when you get to power uprate, when you're looking at power levels going up and water levels coming down.

When you're getting into those ATWS situations, the symptoms are going a little bit faster. So the operator is going to go through his motions in the same time period. The two minutes is what we're assuming in the analysis. It's not a number coming out -- it's not a number calculated from the analysis results.

VICE CHAIRMAN BONACA: Okay. thank you.

MR. SCOTT: Okay. One thing we have done is to raise the minimum allowable standby liquid --

CHAIRMAN APOSTOLAKIS: Let me understand this. The two minutes are used in the analysis. What

analysis is this?

MR. SCOTT: Dan, can you --

MR. PAPPONE: This is Dan Pappone again. We perform a safety analysis to confirm that the peak vessel pressure, the peak suppression pool temperatures, are going to be acceptable. And in performing that analysis, we have to make certain assumptions, say, on operator reactions, because we're using --

CHAIRMAN APOSTOLAKIS: So the shorter you assume the action is, the more optimistic you are, aren't you?

VICE CHAIRMAN BONACA: That's right.

CHAIRMAN APOSTOLAKIS: So if you are saying in the PRA that the actual number will be around six minutes, and you assume two, then the deterministic analysis is optimistic.

MR. PAPPONE: No. The --

CHAIRMAN APOSTOLAKIS: No? Am I missing something?

MEMBER POWERS: It's the time available.

MR. PAPPONE: The PRA analysis is looking at the maximum time available for the operator to perform those actions as part of a success criteria. He has a period of six minutes or nine minutes to

perform that action.

CHAIRMAN APOSTOLAKIS: Okay. And in --

MR. PAPPONE: And if he completes that action within that time, then the event is successful. If he fails --

CHAIRMAN APOSTOLAKIS: Right.

MR. PAPPONE: -- if he fails to complete that action in that six minutes, then that's considered failure.

CHAIRMAN APOSTOLAKIS: Right.

MR. PAPPONE: It's just a simple success criteria on the PRA side.

CHAIRMAN APOSTOLAKIS: Yes. Well, I mean, if I do the deterministic analysis --

MR. PAPPONE: The deterministic analysis --

CHAIRMAN APOSTOLAKIS: -- it's six minutes down to two minutes.

MR. PAPPONE: No, no. The --

VICE CHAIRMAN BONACA: The deterministic was a previous analysis they did for licensing --

MEMBER SHACK: No. But George's point is if they used six minutes in the deterministic analysis, they wouldn't have liked the answer.

MR. PAPPONE: Absolutely.

CHAIRMAN APOSTOLAKIS: And, therefore, would you fill in the blanks there?

MR. PAPPONE: The deterministic analysis has certain levels of conservatisms in the code. So that's going to -- and methods that we're using. So that's going to push the answer above what we'd like to see. In the PRA analysis --

CHAIRMAN APOSTOLAKIS: But we can't separate the PRA analysis from everything else. I mean, it's not a different world.

MR. PAPPONE: But it's a different set of -- it's a different set of modeling assumptions that are used in the calculation.

CHAIRMAN APOSTOLAKIS: For the same system.

MR. PAPPONE: Right.

CHAIRMAN APOSTOLAKIS: Yes. So, you know, which ones do we go by? I mean, would the calculated temperatures and pressures change significantly if you assumed a realistic six-minute response time?

MR. SCOTT: In my experience, as an operator and watching the crews train, and being a part of the crews in training, is that the PRA analysis versus the two-minute analysis, it doesn't matter to me. You know, my actions are the same.

I'm going to step through, and I'm going to do those actions in the same amount of time. I can get those actions done in two minutes whether we have a power -- whether I'm at 50 percent power or 100 percent power or at 120 percent power. It doesn't matter.

I think the key is that as long as we can say that, yes, the times change from nine to six minutes, and two minutes is still bounding, I'm comfortable as an operator in being able to take those actions to protect the plant.

CHAIRMAN APOSTOLAKIS: Right. And you are speaking now in PRA space, the response of the operators.

MR. BURCHILL: Well, this is Bill Burchill again. I want to clarify one thing, Dr. Apostolakis. The PRA doesn't calculate that it will take the operator six minutes.

CHAIRMAN APOSTOLAKIS: I understand that. I understand that. It's the deterministic analysis that bothers me.

VICE CHAIRMAN BONACA: Yes.

CHAIRMAN APOSTOLAKIS: I mean, the --

MEMBER SHACK: Well, he's using a more conservative analysis. You know, it's sort of a

bounding analysis versus a best estimate. So that when he does the bounding analysis --

VICE CHAIRMAN BONACA: Yes. But two things bother me there. One is that for the deterministic analysis there must have been a best case that was analyzed some time in the past for this plant that said that, based on conservative estimates of what it takes to reach those points, it takes two minutes. Okay?

And now you are saying you feel comfortable with two minutes, and I don't. I mean, at some point I will become uncomfortable.

MEMBER SHACK: Well, I think the answer is he takes the action in two minutes.

VICE CHAIRMAN BONACA: I understand.

MEMBER SHACK: And, you know, he gets 1440 in one case and 1477 in the other. So as he keeps the time fixed and he ups the power, the temperature does go up, which is what you would expect.

VICE CHAIRMAN BONACA: Yes. No, but I was saying that now I would have expected that if you now go up in power you will have a change in that time.

MEMBER SHACK: He kept that time fixed, presumably because the regulator accepted the two minutes, and so he lives with the two minutes and sees

what happens.

MR. CARUSO: Dr. Bonaca, this is Ralph Caruso from the staff. I've been informed that I believe that the two minutes was a number that came about as part of the original ATWS rulemaking.

VICE CHAIRMAN BONACA: That's right.

MR. CARUSO: That was an input assumption that was established at that time as a reasonable amount of time for an operator to respond to these. So that's an input to these assumptions.

I believe also there's a comparison going on here between a deterministic calculation using one particular GE code and the PRA calculations which are done using the MAP code, which is an entirely different code. So you get -- unfortunately, you get different numbers when you use different codes.

VICE CHAIRMAN BONACA: I understand. But the fact is, you know, it's important we understand how going up in power -- okay, what effect it's going to have on operator reaction.

MR. CARUSO: Yes.

VICE CHAIRMAN BONACA: And time is always an effect on that. There may be confidence on the part of the operator that he can perform the action, but at some point the confidence will be decreased,

just because time is an issue for him to detect, to respond, and to take action.

So that's why we're pursuing this kind of questioning, and it's confusing to hear an assumed number of two minutes for the ATWS and, you know, there -- I would have to look at the analysis to understand why it's done in a particular way, because you cannot get an input from that. And, therefore, we have to depend on the MAP analysis to get the sense of time dependency. That's the whole issue.

CHAIRMAN APOSTOLAKIS: So we have to live with the two minutes, then. This is something that's --

VICE CHAIRMAN BONACA: I guess so.

CHAIRMAN APOSTOLAKIS: -- NRC given.

MEMBER KRESS: Well, the two minutes --

MEMBER SHACK: NRC accepted at least.

MEMBER KRESS: The two minutes in the original rule must have come out of observations on simulators and saying, "Well, they've always" --

MEMBER POWERS: Oh, I wouldn't think so. I bet -- I bet the original analysis came out a wide-ass guess with a bunch of conservative --

MEMBER KRESS: Well, it's one of --

MEMBER POWERS: -- considerations.

MEMBER KRESS: It could be one or the other.

MEMBER POWERS: It could be one or the other.

MR. CARUSO: I am informed by people who have some knowledge of this that this arose out of the recirculation pump trip time. And there are a number of different things that go into this 120-second value that's used. We can identify this for you in more detail if you wish, where it came from, but I think the issue here really is, for the deterministic analysis, they use a value of 120 seconds, then come up with a certain result which is acceptable.

In PRA space, they've determined that they might be able to go even longer, might be able to go six or nine minutes.

VICE CHAIRMAN BONACA: Okay.

MR. CARUSO: Okay? But as the operators here are saying, they feel comfortable that they would recognize these symptoms and respond to them very quickly. So there is a little bit of a disconnect here, but it's -- I think it's explainable and understandable. It's more of an artifact of the way that the different methods calculate these parameters.

CHAIRMAN APOSTOLAKIS: So if they respond

in six minutes instead of two, in real life now, the peak clad temperature will be higher than this, won't it?

MR. BURCHILL: This is Bill Burchill again. No. In fact, if they respond in the six or nine minutes, depending upon the number of pumps, they will meet all of the success criteria in the PRA analysis. It's likely you would not meet the licensing limit, but you would be using an apples and oranges comparison because --

VICE CHAIRMAN BONACA: The 2200 degrees? Is that the licensing --

MR. BURCHILL: Right. But that also has restrictions on the -- you know, the various inputs to the calculation, the heat transfer correlations, and all of that stuff that we're -- you know, traditionally imposed on the design basis analysis, which would not be true in a realistic analysis that's used for the PRA.

CHAIRMAN APOSTOLAKIS: So where does that leave us? I don't understand that. Now, are you saying --

MEMBER POWERS: Wherever it leaves us, let's move on, so that I cannot destroy your schedule.

MEMBER KRESS: It leaves us with the

thought that the idea of using best estimate codes with 95 percent confidence was a pretty good idea, because you can understand what the number is.

VICE CHAIRMAN BONACA: Well, I think it would have been interesting I guess -- and I really don't need -- I accept the fact that two minutes in the design basis analysis are acceptable for both conditions. I would have liked to know at what point I could see those two minutes -- what number does it become before it becomes unacceptable? You know, to understand what -- how the margins --

MEMBER POWERS: It depends on -- it depends critically on whether you're taking core damage as your criteria for acceptability or 2200 degrees Fahrenheit as your criteria for acceptability.

VICE CHAIRMAN BONACA: I mean, whatever was the licensing value.

MEMBER POWERS: I mean, it seems to me that had I known when I did the analysis for peak clad temperature that my maximum temperature was going to be 1440, I would have said, "Well, instead of putting in two minutes for that criteria, I'll put in three and a half, because I've got more room and I like my operators. I don't want to put too much torque on them." And, indeed, they would have probably found

that they met the 2200.

If instead they said your criteria is core damage, they might well have been able to put in seven minutes.

VICE CHAIRMAN BONACA: Well, I understand that, but that was --

MEMBER POWERS: Or 15 minutes maybe.

MR. CARUSO: Dr. Powers, I mean, actually, you're focusing on peak clad temperature here. For ATWS events, the more limiting parameter is the pool temperature.

MEMBER POWERS: And if I bring that up, I protract a discussion that's already gone on too long. Okay?

MR. CARUSO: Oh, okay. I just wanted to make that point. Everyone is focusing on peak clad temperature, but in an ATWS really the limit that you're going to hit first is the suppression pool temperature. That's more important than the peak clad temperature, because you've got water going through the core. So you -- it's -- you're going to keep --

MEMBER POWERS: They were trying to understand where the time comes, and I was --

MR. CARUSO: Okay.

MEMBER POWERS: -- trying to point it out

to them. And even if you had taken the suppression pool temperature in PRA space, that's not too important. What is overpressurization of the drywell becomes important.

MR. CARUSO: Right.

MEMBER POWERS: And the times even go longer than that.

MR. CARUSO: Right.

MEMBER POWERS: Can we go ahead?

MR. SCOTT: Certainly. Okay. One thing that we have done is to raise the minimum allowable standby liquid control boron concentration with --

MEMBER POWERS: The points that you might want to make is, where do you inject your boron into this core?

MR. SCOTT: The boron goes in through the high pressure core spray sparger, which goes right onto the core, so it's a core --

MEMBER POWERS: On top of the core.

MR. SCOTT: That's correct.

MEMBER POWERS: And not on the bottom. And so now you're not relying on raising and lowering the water to mix the boron.

MR. SCOTT: That's correct.

MEMBER POWERS: That's an important

feature of this plant.

MR. SCOTT: Thank you.

So we are raising the minimum allowable standby liquid control boron concentration to ensure the rate of negative reactivity addition remains acceptable after the power uprate. And we have included the table here. I'm showing some of the major parameters pre- and post EPU, along with the associated design limits.

And just to conclude, that these values show and support the acceptability of maintaining the existing operator response to an ATWS after implementing the power uprate.

So now I'd like to introduce Harold Crockett from Exelon Nuclear, who will discuss plant response to flow accelerated corrosion.

MR. CROCKETT: Thank you, Kent.

I'm Harold Crockett, and I'm the flow accelerated corrosion program manager for AmerGen and Exelon, and I'd like to talk with you a few minutes about our program and what we have done.

The Clinton station has a program that is consistent with the industry recognized EPRI recommendations for flow accelerated corrosion, and what we have done is we have updated our analysis with

the new design conditions.

MEMBER POWERS: And the spelling of CHECKWORKS.

MR. CROCKETT: Yes. And as noted, we use the EPRI program CHECKWORKS. It is a predictive analysis. And because our analysis is largely cycle-dependent, dissolved oxygen temperatures flow, we want to look at each line that is modeled.

And so what we did, we saw the results, and in our particular station here, the scavenging steam line had the most significant increase. And we wanted to cite this example, because the numbers are a little bit high in the world of fact.

Normally, there are generally small numbers -- wear rates are maybe five mils per year and you get a 15 percent increase, so you're up to a whopping six mils per year. This one was a little bit higher. We went and focused on this particular line and looked at the actual measured wear and compared it with the previous predicted wear. Actual measured wear was about 20 mils per year, and the old predicted methodology gave us 38 mils per year.

And what -- the goal is to merge the predicted with the measured and get a refined correction factor on this --

MEMBER POWERS: Well, somehow 52 mils per year doesn't give me much more comfort than 70 mils per year.

MR. CROCKETT: That's correct. And as we'll note further down, this particular line we will be visiting for replacement. We have found that proactive replacement is a good policy for us if, at the same station we've seen wear, or at our other stations we've seen wear.

By the time you put up the scaffolding and remove the insulation, you've spent so much effort that a lot of times it's easiest just to go ahead and upgrade it with chrome-olly and stainless. And yes, sir, you're exactly right. We have done that, and we continue to do that.

We've learned a lot in the past decade about which lines are wearing. And Clinton being a younger station, they're just getting to the point where they're doing some of these replacements.

MEMBER FORD: Maybe it's a moot point if you're going to replace the carbon steel steam line with chrome-olly. But could you comment on the qualification of CHECKWORKS for wet steam? Given the fact that there are different corrosion mechanisms or different corrosion criteria between wet steam and

water. So how well has CHECKWORKS been qualified by observation versus prediction, with steam versus water?

MR. CROCKETT: Yes, sir. The check family predictions -- the CHECKWORKS, it is set up for a single phase and two phase, and steam quality is an input. And we continue to refine the code. There has not been a dramatic amount of changes in the past eight years. There's been some small refinements.

EPRI sponsors meetings twice a year, and we are very active in those meetings, which is the domestic utilities as well as the international utilities. We have strong support from around the world at these meetings. And when we're seeing high wear we go visit those very areas. So it's -- everybody is pretty much talking to each other.

MEMBER FORD: Would the fact that there are different mechanisms involved, between those two environments, is it fair --

MR. CROCKETT: Yes, sir.

MEMBER FORD: -- is it fair to use CHECKWORKS from one -- from water and then just do a flip to steam?

MR. CROCKETT: Right. As I mentioned earlier, steam quality is an input. And what we're

really talking about is not a mechanical attack. It's a corrosive attack. It's a dissolution of the oxide layer -- washes away, dissolves the next oxide layer, and repeats itself.

And it is different, but the code has been consistently substantiated where it has been used. And there have been some industry events, and the code was not properly used. I think at the last subcommittee meeting --

MEMBER FORD: Okay.

MR. CROCKETT: -- they talked a little bit about Fort Calhoun's rupture. And when they did go back and look at the code and properly analyze it, it did have wear rates that were exactly or very consistently with the --

MEMBER FORD: But a difference between less than 20 and 38, between measured and calculated, that's not unusual. Is that unusual or not?

MR. CROCKETT: That is not unusual to have a predicted off by that much. And that's why we continue to select, inspect, and evaluate, and feed it back into the process. It's not unusual for it to be off by that much.

MEMBER FORD: And is a discrepancy always the same way?

MR. CROCKETT: No, sir. It can be --

MEMBER FORD: Plus or minus.

MR. CROCKETT: That is correct.

MEMBER FORD: Oh, okay.

MR. CROCKETT: It could be more than measured in a prediction or less.

MEMBER FORD: Okay.

MR. CROCKETT: As I mentioned earlier, the model will continue to be calibrated with post-EPU conditions. And these changes were anticipated. We talk about power uprates at our conferences, so the code is consistently applied.

The schedule replacements, we will continue to inspect this particular line, both trains of it. So if we get up to data we receive from this particular outage that will start up next month, we may elect to proactively replace this line even before that time. But it is an ongoing process.

And the programmatic controls are in place to ensure that inspections continue, and the extent of the condition is assessed. So if we find wear, we'll measure upstream and downstream and that -- that analysis.

MEMBER POWERS: Let me just ask one point of fact. This line that's corroding at 70 mils per

year in your analysis, what's the wall thickness on it?

MR. CROCKETT: This is a half-inch wall thickness.

MEMBER POWERS: Half-inch. And I can't resist just pointing out that programmatic controls were in place at Fort Calhoun and Surry.

MR. CROCKETT: Well, Surry certainly was the birthplace of the modern codes. And Fort Calhoun -- I was asked to be on a team that assessed that particular station. And prior to their rupture, they had not been active with the industry meetings. And their analysis was partial I guess would be the way to address that.

MEMBER POWERS: A generous way to put it.

MR. CROCKETT: Yes.

MEMBER SHACK: What are your wear rates in your feedwater lines?

MR. CROCKETT: Feedwater lines -- BWRs typically, because of the dissolved oxygen, are not high. Some of the PWRs have had some feedwater replacements --

MEMBER SHACK: It's a big difference. But just -- I mean, is it a couple mils a year?

MR. CROCKETT: On the order of five to 10

mils per year. And that's a much thicker pipe typically. That's an inch and a half or more.

Yes, sir.

MEMBER FORD: I have a question, not related to flow assisted accelerated corrosion. Fluent use vibration -- I recognize that fatigue is probably another problem in the upper head. However, there have been stress corrosion problems of core spray lines and dryers, and this was brought up at the Quad Cities and Dresden applications.

We raised the question about whether there's a loose parts problem, and we were assured that it was not a problem. Has this been revisited for this particular station -- Clinton?

MR. MOSER: Yes. Dr. Ford, Keith Moser, Exelon, Reactor and Internals Program Manager.

Yes. We did exactly the same thing we did for Dresden and Quad. We went back, component by component, looked at all of the different problems. And as you suggested, flow-induced vibration was one of the issues we looked at. You know, for this plant, we didn't have to put in any mods. Everything worked out fine. The dryer we looked at before. We're going to be looking at it right after this outage.

Again, we don't think there will be any

issues. But we do have programs in place to look at it, and we will be looking --

MEMBER FORD: My concern was entirely the fact -- I'm not concerned about exceeding -- that it's going to cause fatigue. I'm more concerned about exacerbating cracking, stress corrosion cracking, by the fact that you're superimposing a vibrational load, which has been increased because of the EPU.

Therefore, if you're going to inspect once every outage, which is appropriate, is that good enough?

MR. MOSER: For which component in particular?

MEMBER FORD: Well, I was thinking of core spray lines, steam dryers, the brackets holding the steam dryers to the pressure vessel. They have all undergone stress corrosion cracking at one time or other.

MR. MOSER: You know, for the core spray lines, flow-induced vibration really isn't a big problem in those lines. The steam dryer, yes, we have concern, and we have some industry experience on that -- Peach Bottom, some other overseas plants. But based on the fact that the loose parts issue got such a big dryer, big component, even if it would crack

there's nowhere for it to go, and it's not a safety concern.

MEMBER FORD: Except down.

MR. MOSER: Yes. But that would go right on top of the separator, correct?

MEMBER FORD: That's correct.

MR. MOSER: And so, in a sense, you don't have anything that can really cause you concern as far as a safety perspective. And so from that perspective, yes, we are absolutely sure that we want a cycle of looking at the dryers, making sure there isn't any gross degradation -- is the right thing to do.

For the brackets themselves on the RPV wall, yes, we looked at them before. There has been some industry experiences. We are going to look at them after the outage -- after the EPU conditions and make sure that we have everything modeled correctly.

MEMBER FORD: Okay.

MR. MOSER: Does that answer your question?

MEMBER FORD: Yes. Kind of.

MR. MOSER: Okay.

MEMBER FORD: Yes.

MR. CROCKETT: In conclusion, the EPU

changes are acceptable to the FAC program.

I'd like to turn the --

MEMBER POWERS: Well, at this point, I'm going to intercede. We've exceeded the allotted time for this. This is not a risk-informed submission. I believe those interested in the risk significance of this submission can read the viewgraphs, and I propose that we move right to the closing. And any points you want to make about the implementation you can make there.

MR. SIMPKIN: I am Terry Simpkin. I'm the Manager of Licensing for Exelon Nuclear. First of all, I'd like to thank the staff for their rigorous review and I'd like to thank this Committee for its consideration of our request to uprate the power level at the Clinton Power Station.

We have completed extensive analyses, using accepted methodology. We have identified no significant impacts on plant response or system integrity. Our request involves minimum changes in plant risk and we believe that plant operation is acceptable at the extended power uprate conditions. Subject to any questions from the Committee, this concludes our presentation.

MEMBER POWERS: Do Members have any other

questions they would like to pose on this to the licensees about this?

Well, thank you very much, gentlemen, and I'm sorry to eliminate a couple of sections of your presentation, but I think the visual aids were very clear and made your essential points there.

I'd like now to call on Mr. Zwolinsky to make a presentation for the Staff and their review of this application.

(Pause.)

Mr. Zwolinsky, I understand that in the course of teh Staff's presentation we'll have to interrupt the meeting for a protection of proprietary interests?

MR. ZWOLINSKY: This is my understanding.

MEMBER POWERS: You'll let me know when that has to take place?

MR. ZWOLINSKY: Yes sir.

MEMBER POWERS: Please.

MR. ZWOLINSKY: Good morning. For those of you that don't know me, my name is John Zwolinsky. I'm the Director for the Division of Licensing Project Management. Staff is here to present its review of the 20 percent power uprate request for the Clinton Plant.

I'd like to take a minute to acknowledge several of our management team that are in attendance today that are clearly supportive of our staff and are here to represent that support, beginning with Suzanne Black, our Deputy Director for the Division of System Safety and Analysis; along with her, we have Gary Holahan, the Division Director of the Division; John Hannon, our Plant Systems Branch Chief; Ted Quay, our Equipment and Performance and Human Factors Branch Chief; Singh Bajwa, our Project Director responsible for power uprates. We also have a number of our Section Chiefs, our first line supervisors responsible for assuring a high quality product: Dale Thatcher in the Equipment Performance Branch; Corney Holden, Electrical and Instrumentation and Control Systems Branch; Matt Mitchell from our Materials Branch; Ralph Caruso, of course, from Reactor Systems, Kamal Manoly from our Mechanical Branch; Brian Thomas from our Plant Systems Branch; Louise Lund from our Materials Branch.

I go through that only to articulate the sense of importance that we place on assuring that top notch products are generated and thatwould be in response to the Committee and any concerns or questions that may arise.

The Staff made a presentation on this review to the Subcommittee on thermohydraulic phenomena on February 14. The Clinton power uprate is similar to the Duane Arnold, Dresden and Quad Cities power uprates which were reviewed by the ACRS late last year. Clinton's application does deviate from teh approved ELTR1 and 2 methodologies for GE BWRs and extended power uprates in four areas. These areas are and we did go through this with teh Subcommittee, transient analysis, LOCA analysis, stability and large transient testing. The Staff will discuss these areas today.

The Staff has conducted thorough reviews of the Clinton power uprate with the focus being on safety. The reviews were conducted consistent with the existing practices which includes the lessons learned from Maine Yankee. As indicated in the draft safety evaluation, many areas affected by the power uprates have been reviewed and evaluated and results were transmitted in that draft safety evaluation report. We have additional work to perform in cleaning the safety evaluation up.

With that, I'd like to get on with the presetatnions. Our lead project manaber for this particular facility, Clinton, is John Hopkins. John

will walk up through the presentations as we go forward and as I said earlier to Dr. Powers, our staff is available to answer any questions associated with the presentation or beyond.

MEMBER POWERS: Let me ask you one question. You said this was similar to the ones we've looked at before including Quad Cities, Dresden. It strikes me, in fact, that this is simpler than those.

Clinton just seems like a much easier power uprate than those other plants have. Is that your kind of sense or not?

MR. ZWOLINSKY: The amount of time that we spent, staff time in reviewing especially Quad Cities and Dresden was quite large compared to the other applications. We did not spend as much time reviewing this application. That would be a metric.

MEMBER POWERS: That may or may not be a metric, but I mean the general amount of changes, the effort that they have to go to and the changes -- I mean, I point to just the power uprate is much easier in this plant than --

MR. ZWOLINSKY: Yes sir. I think as a general comment, I think we can agree with that.

MEMBER POWERS: Good.

MR. ZWOLINSKY: John.

MR. HOPKINS: Good morning, I'm John Hopkins, NRR Senior Project Manager assigned to Clinton. I'll go quickly over the overview. To start with, I'll be starting and then our next presenter will be Plant Systems area and then we'll have -- discuss large transient testing and then in the end, we'll discuss reactor systems and those exceptions. We will need to close the session for when we discuss those, even though the handouts are all nonproprietary. We really have to close it to discuss it.

To start with, as has been previously stated, this is a BWR6 Mark III. After the 20 percent uprate is completed, Clinton will still be just the third largest BWR6 as far as megawatt thermal power is considered. Perry will be slightly larger and Grand Fulf will be about 400 megawatt thermal larger.

The licensee went through many balance of plant mods to accomplish this uprate. GE14 fuel is being used and they'll have about a two-thirds core after they start up from this upcoming refueling outage which is projected to start April 2nd.

MEMBER POWERS: Maybe you better be clear by what you mean by two thirds core.

MR. HOPKINS: Two thirds GE14.

MEMBER POWERS: You are not loading jsut two thirds of the core.

MR. HOPKINS: Okay, I'm sorry. I was trying to go quickly.

(Laughter.)

This application came in in June of last year and so it's been a fairly quick review. To respond to you, Dr. Powers, what you asked John, I think this has been a simpler review. They already have had GE14. They already have had MELLLA approved for this plant. There's no recirculation, new recirc runback system associated with the plant, so I do think it's been simpler in those regards.

It is on 18-month cycles. However, this next cycle is expected to be run approximately 20 to 21 months and I expect to get an application to go to 24-month cycles during that time.

It is nonrisk informed as previous EPUs, however, risk was looked at and we did not identify anything that would argue against the uprate.

AmerGen is the licensee and they have previous experience in operating applications as the staff does also.

We have one license condition at this time. It's on a feedwater nozzle cumulative usage

factor. The licensee is still performing analyses of this and they expect to submit the analyses to us fairly soon and so we'd condition the license for the next operating cycle for us to review these analyses and then find them acceptable.

MEMBER POWERS: John, just for Members' information. Your cumulative usage factor refers to the fatigue issue?

MR. HOPKINS: Yes.

MEMBER POWERS: And it is a thermal fatigue or vibrational fatigue?

MR. HOPKINS: My understanding is it's thermal fatigue.

They list the four exceptions there. We will discuss each of the four exceptions during this presentation. Again, teh first three will be discussed at the last presenter and that will be closed.

Right now, unless there are any other questions, I'm going to briefly discuss flow acceleration corrosion. This is a question that came out of the Subcommittee meeting and the qeustion I received was basically when NRC inspectors look at flow acceleration corrosion, what understanding do they have of it and what resources can they tape to

help them?

MEMBER POWERS: I think more so than that particular question is do the people doing the inspection of programs at the plant understand from you in looking at this power uprate quest that there are certain critical copmonents including teh scavenger line where flow acceleration corrosion could be high and the licensee is relying very heavily on programmatic issues, constraints to assure this doesn't get out of hand.

MR. HOPKINS: My answer to that is we are, the staff is developing a power uprate inspection procedure at this time. It's out to the Regions for comment. We expect to finalize it in a few months.

One issue that's being considered to be included in there, specifically FAC. Now all of our inspections are based on risk importance and mainly from a nuclear safety perspective. So I don't --

MEMBER POWERS: It seems to me one of the problems you're going to run into is that we're talking about flow acceleration corrosion in a line that probably doesn't rank very high on a risk analyses, but when you break these lines, they typically have some pretty substantial conseqeunces, nevertheless.

So you worry about using risk where you're talking about damage to the public in tehse kinds of context.

MR. HOPKINS: I undrestand that. I think we'd have to get back to you as we develop our uprate inspection procedure to fully respond.

MR. ZWOLINSKY: I think your comment is a fair comment. Yesterday, at the Regulatory Information Conference, Jack Robe was our Division Director for Reactor Safety and Region 3 was presenting the inspection program that was conducted at Quad Cities, Dresden and Duane Arnold and he did not get to that level of specifics, but they did implement a specific inspection program, targeted to power uprate, seeking key vulnerability that they felt had been identified not just in the application, but in the safety evaluation.

MEMBER POWERS: I think that's what needs to -- there needs just to be some communication here.

MR. ZWOLINSKY: Okay, the left hand and right hand were clearly communicating and I think that was one of the major points he was making.

MEMBER POWERS: Very good.

MR. ZWOLINSKY: But as John alluded to, we are developing the temporary instruction for more

uniformed inspection across the country.

MEMBER POWERS: If you happen to have the slides from his presentation, I'd enjoy seeing them.

MR. ZWOLINSKY: We can forard those to you.

MEMBER POWERS: Okay.

MR. HOPKINS: Okay, at this time I'd like to introduce Richard Lobel who is from our Plant Systems Area. And he will talk about another question from the Subcommittee on spent fuel pool temperature distribution and briefly discuss contributory containment analyses that we performed on Clinton.

MR. LOBEL: Good morning. I was giving a presentation on the plant system's areas of review for the Subcommittee and a question came up about the temperature distribution, the water and the spent fuel pool and I said that I believe there had been studies done on that. Let me just go over it briefly.

The heated water in the spent fuel pool is collected around the periphery of the pool and circulated through heat exchangers and then discharged at the bottom of the pool to enhance circulation. The power uprate doesn't change the design aspects of the spent fuel pool, cooling, the circulation mixing patterns and the operation of the spent fuel pool.

Based on staff experience, it's not power uprate, but spent fuel pool reracking that results in the greatest increases in spent fuel pool temperatures and we have reviewed many rerack applications. As part of that, the staff reviews the thermal hydraulic analyses including the maximum water temperatures with and without water circulation, without forced circulation. In one rerack review that was done a while ago, the staff performed extensive two and three-dimensional calculations of the water distribution in the spent fuel pool, compared the calculations with the licensee's calculations and concluded that the license's calculations were conservative.

As we discussed with the Subcommittee, the spent fuel pool water and the fuel temperature increases aren't a concern for the Clinton power uprate. Their analyses show that they're below the spent fuel pool limits.

I hope that answered the question.

MEMBER KRESS: Those limits are set based on the concrete --

MR. LOBEL: Right. The limits are really separate from the question of the temperature distribution. There's a limit because of the material that's used in the purification system and there's a

limit of 150 degrees on the concrete. And Clinton was well below both of those limits.

MEMBER KRESS: Was the temperature distribution significantly different from what it is normally?

MR. LOBEL: Well, it depends on the loading pattern and the density of the loading pattern and that's why the reracking really has more of an effect than the power uprate. Typically, in a rerack you're moving the fuel closer together and higher energy density into the same amount of water.

MR. ZWOLINSKY: Dr. Kress, the biggest issue we've identified is length of time that the licensee retains the fuel in the core and it's initial configuration from shutdown. The longer it cools in the reactor vessel and then transfers over to the pool, the smaller effect it has on the pool's temperature.

MR. LOBEL: Also at the Subcommittee meeting I mentioned that we were doing confirmatory analysis for the containment calculations and at that time I wasn't sure whether we'd be done in time for this meeting, but it turns out that the calculations are completed and if you'd like, we can talk about that a little.

MEMBER KRESS: Yes, I think we would like to.

MR. LOBEL: Well, let me introduce Edward Throm from Plant Systems Branch who did the calculations and he can discuss it.

MEMBER POWERS: Well, maybe you better get the speaker on with a mobile microphone.

(Pause.)

MR. THROM: Am I on? Okay, real quick, my name is Ed Throm. I'm with the Plant Systems Branch and what we attempted to do in a very short time was do some confirmatory calculations for the Clinton extended power uprate.

What we wanted to do was look at the contained two which is the staff containment code and compare it to the M3CPT and SUPERHEX results that GE typically calculates.

We started off with an existing Grand Gulf Mark III deck and modified it to look like Clinton. This modification is dry well/wet well. Volumes, initial conditions to reprsent th eplant. We used the mass and energy releases provided by the licensee directly and this leads to a little bit of a discrepancy and one of the results of that I will show you.

This particular time we've done three calculations, two short term for the recirculation line break and then the steam line break and we also did the recirc line long-term cooling temperature response calculation. We couldn't do the shutdown calculation in a short time because that would have required additional model changes that I didn't have time to do. And basically, by looking at the qualitative comparison for the studies we've done, we believe that our conclusion that the licensee's analyses are acceptable for the extended power uprate is a true statement.

The model is fairly simple. It's basically got three models of dry well with the annulus region that connects to the wet well and for this particular design it has the three vent paths.

I'm just going to put up two results because of time. This is the short term recirculation line break. This is a comparison of the contained results to the M3CPT. As you can see, M3CPT is calculating a little higher pressure than the staff's calculation and overall the dry well temperature response is very consistent with the licensee's calculation.

And the long term break, this is one of

the areas where you learn as an analysis that you may have missed a piece of information that was important if you were trying to do it, an audit calculation and what's happening here is by using the licensee's provided mass and energies, we got a very coarse set of data and the data tends to show more of a steam release, high energy release over the initial portion of the transient. That's why we're predicting this higher initial pressure response and a slightly higher temperature in the suppression pool.

This is very evident from that little spike there, where we have three points, one at a liquid, one at a steam, and one at a liquid. So we've just done a linear interpolation so that's what the offset is doing for these types of calculations. But again, qualitatively, we don't see anything between the two codes that suggest that the analysis method that's been approved and accepted by GE, by the staff or GE plants is any different for Clinton than it was for the Duane Arnold which basically the staff did a similar evaluation for Duane Arnold. That's pretty much what I have to present.

MEMBER KRESS: Thank you.

MR. ZWOLINSKY: Thank you, Ed.

MR. THROM: Okay, sure.

MEMBER POWERS: Thank you.

MR. THROM: Sure.

MR. ZWOLINSKY: Okay, our next presenter will be Bob Pettis and he'll talk about the exception from ELTR1 and 2 to not perform large transient testing.

MR. PETTIS: Good morning. My name is Bob Pettis and I'm with the Quality and Maintenance Section within the Division of Inspection Program Management.

Our review of the Clinton application focused on the testing section of the application with some specific attention to the exception for not performing a large transient test. The Clinton EPU tst program follows ELTR1 which is basically delineated in Appendix L2.

As discussed previous by the Applicant, Clinton will perform a limited subset of original start up tests to demonstrate capability of the plant systems to perform as designed through the EPU power extension. Routine measurements are taken for reactor and system pressures, flows and vibrations, up through EPU conditions and main steam and feedwater systems will be monitored for vibration.

The exception to ELTR1 is in the area of

the mainsteam valve closure and generator load reject tests. This exception was also previously approved for the Dresden and Quad Cities EPUs.

The staff felt that the exception to the ELTR1 is acceptable for several reasons. First reason, GE had stated the constant reactor dome pressure simplifies the analyses and plant changes to achieve EPU conditions.

Text spec surveillance testing will confirm the performance capability of the compnents challenged by large transients. Another point is that CPS is not installing any new safety-related systems, features or significant additional components as a result of achieving EPU. There are some balance of plant modifications that were discussed previously.

An analysis was also performed by the licensee in coordination with GE that reviewed some of the compnents that would be challenged by large transient testing. Some of those components included MSIVs, safety relief valves, turbine stop valves and turbine control and bypass valves. They also reviewed main steam line geometry and control rod insertion times.

The CPS test program also will monitor important plant parameters during power ascention,

operating preassures and flows, temperatures, vibration and closure times for MSIV turbine stop adn control valves. Operating history and experience at other BWRs has also been recognized. There's been a slide that was presented yesterday that was more extensive than this, but the KKL plants or the KKL plant is operating at 116 percent; the KKM at 117; Monticello at 106; and Hatch around 113. And also, the Dresden, a plant as well.

MEMBER POWERS: Have any of these plants performed the equivalent of a large transient test?

MR. PETTIS: To our knowledge, the only plant that has was the KKL plant in Sweden and from what we have reviewed, at least in our section, those results appear to correlate very well with the analytical models that would ahve predicted the resonse to the tarnsients.

MEMBER POWERS: What I'm struggling with is what you mean by operating history and experience at other uprated BWRs. If say one has performed the test, that's not a whole lot of experience to judge them, is there?

MR. PETTIS: Well, the way that should be looked at is KKL did perform the large transients and there is information that correlates well for the KKL

plant.

MEMBER POWERS: Okay, so if I were to rewrite the line, it would say we have one plant that's done this test and it seemed to match the code predictions and so we'll live with code predictions?

MR. PETTIS: The expectation level, I think, has been achieved with KKL. With respect to the domestic plants, the only experience tehre that we're trying to demonstrate is the fact that they have undergone EPU conditions. They are operating at EPU or near EPU conditions with no anomalies.

MEMBER SHACK: They had a transient at Hatch, right?

MR. PETTIS: Yes, that was in 1999. It should also be noted that Clinton is not making any modifications to the reactor recirc runback system which was an area of concern for one of the ACRS Members previously for Dresden and Quad Cities.

Large transietn testing is also not needed for code validation. I believe that's probably the ODEN code, but I'll let our reactor systems folks discuss that.

And also, the incident that did or the event that happened at Hatch in 1999 where they experienced a load reject from 98 percent power and

KKL had a turbine trip at 113 and a low generator reject at 104, and both of those events followed again code predictions.

Our conclusion is taht conducting large transient tests would not provide significant new information regarding transient modeling and component performance and that the Clinton EPU test program is acceptable.

Thank you.

MR. ZWOLINSKY: Good job. Okay, I would ask that the session be closed now because we'll be doing our reactor systems.

(Whereupon, the proceedings went immediately into Closed Session.)

MR. HOPKINS: Again, this concludes our presentation. The Staff finds that 20 percent power uprate for Clinton can be accepted and approved. We'd request a letter from the licensee discussing our presentation.

MEMBER POWERS: You discuss, you request a letter from the licensee discussing yoru presentation? I'm sure they'd be happy to critique you.

(Laughter.)

MR. HOPKINS: They probably will.

CHAIRMAN APOSTOLAKIS: Or disagree with you.

MR. HOPKINS: You got me. A letter from the Committee. Thank you.

MR. ZWOLINSKY: I do thank the Committee for your time and while we may have rushed through a few of our presentations, we were trying to push a number of our Staff before the Committee to give an indication of some of the areas that we focused on.

With that, I feel the staff has completed their presentations.

MEMBER POWERS: Thank you, John. I'm going to pass on a comment from teh Subcommittee and that is that the Subcommittee found that this safety

evlauation report was among the most readable in the power uprates that they had. I know that's been an area of concern for you and the Subcommittee detected real progress in improving the readability of those reports.

MR. ZWOLINSKY: Thank you.

MEMBER POWERS: Mr. Chairman, I think at thi spoint I think we're done with this session.

CHAIRMAN APOSTOLAKIS: Thank you, Dr. Powers. I also thank the representatives from the licensee and the Staff for their presentations and we will recess until 10 minutes past 11.

(Off the record.)

CHAIRMAN APOSTOLAKIS: Okay, we are back in session. The next agenda item is the proposed NEI-00-04 report, Option 2 Implementation Guideline for Risk-informing the Special Treatment Requirements of 10 CFR Part 50.

We sent to the Staff and NEI a set of questions last January and we had an opportunity at the Subcommittee meeting in February, February 22nd to discuss these questions and the rsponses from NEI. The Staff has forwarded the questions to NEI. So -- well, I must also point out as it will be pointed out later, this Committee has also written two reports to

the Commission, one dated October 12, 1999 and the other February 11, 2000 on importance measures and related matters.

So today, we will -- the Staff has requested a letter. Last time, at least, at the Subcommittee meeting, you said that you would like to see a letter with the Committee's views. I assume you still would like to have a letter from us. You can change your midn, if you wish.

MR. REED: Yes, as you'll see in the slides, currently, we're asking for a letter. If there are big issues, show stopper issues that the Committee has that we really need to address in order to go forward and get your concurrence on the proposal --

CHAIRMAN APOSTOLAKIS: Okay, so why don't we start then and see how well -- and then we'll discuss the issue.

MR. GILLESPIE: Well, knowing that the Committee was really going to focus today on categorization process which is kind of a cornerstone of the rule, let me kind of give you just in a nutshell the status of kind of where we stand.

Frank Gillespie, NRR. The rule has been delayed. So the nature of the letter and the nature

of this meeting might be slightly different, so let me kind of give you the context of that. Two things we're still wrestling with that within the staff. One is having a categorization document, guidance document and working with NEI which right now is kind of a work in progress. We sent 17 pages and comments to them and they're digesting them and so it's going to be another iteration.

And the importance of the categorization document going with the rule and being substantially finished or at least let's say at 80 and 85 percent, so the people can understand what the cost of doing this rule is, having a categorization process and committees and other things. So that was considered an important element. Our original schedule for April, even my optimistic view, I said well, let's send up what they have with our 17 pages of comments and that wasn't going to be the right thing to do. It wasn't going to be -- we would not have worked out back adn forth with all the stakeholders the right kind of document, so we've delayed the rule from April to July.

Now, if we can beat July, our criteria really is less to date and is more having both the rule and a guidance document that goes to set. And

taht's our real criteria. And the guidance document has to be close enough that we have a high possibility of general acceptance that it's rational.

So the guidance document is still kind of a work in progress. Besides the guidance document and it might be a subset and I know you're not here to discuss this, but in my mind they're not unrelated, is the question under special treatment, if you notice the last draft words, the only real special treatment that still is left in for RISC-3 components is 50.55(a). And what the Staff is still grappling with is how to achieve -- how do we write achieving what 50.55(a) is trying to achieve, even for low risk components. And do you have to continue to have 50.55(a) apply or is there a way to deal with that wthin a more performance-oriented approach, for example, within cateogroization. And I"ll give you one example and then turn it over to Tim of -- this is kind of an on-going discussion in the staff so I can't even say ther'es a position on it. There are several positions.

It's not clear to me right now that our current rule and the current guidance says explicitly that you have to consider known degradation mechanisms as part of your consideration in what you're going to

do relative to a RISC-3 component. Yet, does not 50.55(a) try to continue a certain level of assurance for a compnent, even if you're ina risk-informed space which fundamentally is saying we're maintaining our input reliability or the input to our decision process is being sustained.

And so what kind of what we're grappling with is the only way to say to do that for some mechanical components and pressure things and passive things is by dictating 50.55(a) or is there another way of dealing with it in waht the various committees would be considering within the guidance and within categorization.

I've taken my best shot at waht we're grappling with and we've got the staff here. If you want to discuss that later as a point, Tom Scarboro and John Fayer are here, Gareth and Mike Cheof, so we're still grappling with that one point. And it's an important point and we haven't come up with the exact way to deal with it and make that decision yet.

There is a meeting next week where we're trying, going to try to make a definitive decision and the Staffs are kind of working on different points of view and how do you approach that problem. Not a problem, but how do you say what you want to say and

get what you want to get in th emost performance-oriented risk-informed way?

So, that's in my mind those two decisions are not mutually exclusive. And the other comment we did get back to NEI was that these committees, the IDP Committee, we haven't necessarily articualted how they should establish criteria or what the higher level criteria they should be considering is. And that's a piece that we need some time to go back and forth on to discuss because clearly all the components are not considered in the PRA and the mathematical model and in particular, how do you deal with the passive components. Again, not disconnected from 50.55(a) and is that in or out, particularly for passive pressure kind of things.

So that's waht we're wrestling with and with that, I'm going to turn it over to Tim. I talked to George, yesterday, and I've asked Tim to go through the presentation, the formal presentation as quickly as possible, so taht maybe we can get your advice on these questions we're grappling with and we got the staff here that maybe we can have some interactive discussion on it. Because we don't know the right answer.

CHAIRMAN APOSTOLAKIS: Good idea.

MR. GILLESPIE: Thanks, George.

MR. REED: This is Tim Reed from NRR and I have with me also over at the side table Mike Cheof from Gareth Parry to assist here today. The focus here really is focusing on the categorization pieces, Option 2 and looking at what are the remaining key issues that we need to resolve so that ultimately we can get this Committee's endorsement going forward. So that's what I'll be trying to focus this discussion towards.

And this won't look -- this should look very familiar to most of you from the Subcommittee. This tries to give a high level overall status of where we stand on categorization. We recently sent our third round of comments to NEI back in early February and those comments, as Frank mentioned, like 14 pages or whatever, reprsent what the Staff belives are the key issues that need to be resolved for us to reach agreement on the categorization guideline NEI-00-04. They reflect both the Palo Verde activity feedback that we've had to date. We've observed three pilots. In effect, next week is the last pilot, Palo Verde, and we'll be observingt that one two. And they also reflect the staff's review of draft revision B of NEI-00-4. As you're aware, that document is goig to

be revised and it's a work in progress and ultimately will become, I believe, draft revision C.

There are some major issues and I've just hit a few here and there are several other issues in this 14 pages that, in fact, I agree with some of the comments that ACRS brought up in the Subcommittee, but hitting some of the bigger ones here, the issue of long-term containment integrity and how you consider that within the element of defense-in-depth and how the IDP considers taht. That's an issue, that's a comment, you'll see in our comments back to NEI. It's been an on-going issue.

The element of the IDP, the IDP guidance and whether that's sufficiently structured, I think it probably needs a little bit more structure there. That's the nature of our comments. I think the Committee has that. In fact, I think NEI would agree to that to some extent. That's a feedback coming back to the pilot activities also. And then the whole issue of the PRA quality, the use of the PRA review process, how we roll tht in and how the staff develops review guidance to judge whether, in fact, a PRA has sufficinet to support the categorization process. So that's a very key issue here.

All these issues, I believe, from a

technical standpoint, I think the staff belives, can be resolved. So there's nothing here that can't technically be resolved. Taht doesn't mean that we have signfiicant work, but nothing appears to be a technical roadblock at thi spoint.

Of course, we have to come back to this Committee and get -- the Committee needs to see more of a final product, obviously. And so we need to come back for the proposed rule concurrent stage and as Frank mentioned, our schedule at this point is to try to get this to the Commission by the end of July. And so that puts us actually in a very, very tight, difficutl schedule to try to get this Committee, get a letter from this Committee to support that schedule to get this whole package to the Commission by the end of July.

And I don't know if NEI is going to speak today or not, but NEI is in a very tight situation too. They have our comments. They'll hvae the IDP next week. They have to take the feedback from that. Roll it back into NEI-00-04, work through their side to get agreement and then send it to us and then we need to look at that and with the draft reg. guide, get it to the Committee and all taht before July. So you can see there's an awful lot that has to happen

here in the schedule.

So that kind of gives you the high view, the important pieces of categorization and wehre they fit into the proposed rule schedule.

Now these are some of the high points and I'm not going to success that this is the Committee's views. This is what the Staff heard, waht we think are important and I'm sure the Committee would think there are other issues that were discussed that are more important to indiviudal members. But I'm just going to hit a few of the high oints here. But an overriding theme, I think, we heard numerous times during the Subcommittee meeting was that sevearl members mentioned or expressed concerns with the underlying basis that supports the NEI-00-04 document and whether or not that basis is really there, or the document or hte studies there -- is there something you could point to that says yeah, we all agree. I think most people, in fact, agreed, taht they thought it was conservative, but that's more of a subjective judgmetn and I think it was the Committee's view that we probably ened to have more in place as far as something to point to, in fact, that demonstrates more clearly, in fact, that a lot of these assumptions that we're making are, in fact, robust and lead to a robust

categorization.

These were some of the isseus that we took away, the staff took away, you see listed there, what should be the -- what kind of failure rates and what should be the increase in failure rates. AS you're well aware, the numbers are being bantered about between 3 and 5 increase in factor of failure rates for the sensitivities. When you roll this up into the CDF and LERF sensitivities, as you're well aware, South Texas uses a 10. What hsould be the sensitivity? Wht should the nujber be? Should it be a distribution? There's lots of discussion there.

The fuseell-Vesely and the risk acheivement worth screening criteria or guideline values, whta they should be? I think there was even mention of distributions and how you might want to handle that.

There was consideration of rolling up and addressing uncertainties in the whole model, whether that should be done or not. And the whole issue of common cost failure was addressed pretty extensively also. Adn also in combination with RAW, as a matter of fact, at the Subcommittee.

And as I mentioned, the Committee's -- I'll let the Committee speak for itself, but I think

some of the Committee would like to see some of this more documented out there for everybody so everybody could -- and I believe the ACRS mentioned another important comment. I think it agrees with the staff that perhaps the 00-4 guidance, the NEI-00-04 guidance should have a little more structure, a little more guidance to the IDP. I think we think that too. I think it would help to make more effective, efficient, repeatable decisions from IDPs, wherever they occur. I think we all agree with that. I think even Mike even agrees with that to some extgent also.

CHAIRMAN APOSTOLAKIS: After the expert panel makes its determination in whatever way, we're going to work on the process, but let's say at teh very end, they ahve categorized now system structures and components, how do you know that they're right? You're putting all your trust in the process or are there other mechanisms at the end for you to gain some confidence that yes, what they have done is, in ract, reasonable?

Remember now, we're talking about thousands of system structures and components. IN other words, are we approving a process and then telling the licensee go ahead and impleent it and as long as you follow the process, we're happy.

MR. REED: I'll answer the easy part. It is a process approval. To the extent of the confidence in the process and whether the validity of that process is maintianed over time, I'll answer another easy piece of it. That's a function, I think, of monitoring and bringing information, operational experience back into the process and ensuring that you're assumptions, the cateogrization assumtoins are maintained valid over time.

I'll let Gareth and Mike, if you want to say something intelligent than that.

MR. CHEOF: Basically, I think after the IDP categorizes all the SSCs, the PRA is supposed to qualify the change in risk from all the SSCs that are put in RISC-3. Adn this change in risk is supposed to be shown to be small, according to the guidelines we provide in Reg. Guide 1174, but I don't think that's the question you're asking. I think the question is --

CHAIRMAN APOSTOLAKIS: That's part of the process.

MR. CHEOF: That's right, that's part of the process.

CHAIRMAN APOSTOLAKIS: The process has been completed and they go ahead an they categorize

things.

How do yo uknow that what they are doing is reasonable?

MR. CHEOF: I think --

CHAIRMAN APOSTOLAKIS: Not that they are trying maliciously to not implement it, but we're talking about thousands of SSC's here and peoplea re people. They make mistakes and so on.

MR. PARRY: I think Tim was right. In a part of this follow-up is the monitoring of the SSCs and we do have an update requirment for the risk analysis and the process itself that takes into account operating experience. I think the one problem we see is that in the monitoring for the RISC-3 SSCs might also decrease which might not provide you with enough feedback that you might need. So it's something we need to work on.

CHAIRMAN APOSTOLAKIS: Operating experience in these things is probably admitted by you, I would say, because a lot of these systems and components, I mean we are really intersted in their performance during an accident, right? So I mean you would probably be concerned about the proper categorization of particular things and you would not wait until something happens to see whether things

work. Are you planning to have sort of an audit on a random basis or some other basis to get that feeling that things are being implemented the way they're supposed to and the results are reasonsable?

I've heard -- Frank told me the otehr day that the MSIVs wer according to some people were miscategorized at teh South Texas projec. I'd like to know a littl emore about it, why they feel that way. That's a major component. I mean it's something that we can look at.

I don't know, Gareth, if you don't have an answer now, that's fine, but that's osmething that concerns some Members of this Committee. Waht is happening? Are we turning over the responsibilities now to the licensees?

MR. PARRY: There's one other progarm we have on place, the reactor oversight program that I think also has a role in finding degradation for components.

CHAIRMAN APOSTOLAKIS: Good.

MR. PARRY: It obviously is not foolproof, but I think it is -- if there is a finding, then it has to pushed through the SDP and that can -- that may reveal another --

CHAIRMAN APOSTOLAKIS: The actual

oversight process it not really looking at the categorization.

MR. PARRY: No, no, it's not looking at the catgegorization. It would be looking at conditions that might arise because, for example, a lack of treatment in certain areas.

MR. GILLESPIE: This is hard to answer, but the answer is we haven't figured it out yet and I think I want to be careful. The overight program is us overseeing a licensee carrying out its responsibilities.

CHAIRMAN APOSTOLAKIS: Right.

MR. GILLESPIE: And we cannot build in a dependency on our actions for the safety of the facility. And one of the things that we're gropiong with just a little bit this morning and in an earlier meeting was how do we deal with the eact question you're asking. And have we actually, have we necessarliy given either the right commetns in the area of reinforcing -- you're attesting is the quality of the decision. What's our confidence when we made the decision that RISC-3 is really RISC-3? I don't have an ansswer for you, but it was a question that we had on the table and we were kicking it around this morning.

The other question is how do you know that the input criteria tha tyou made you rdecision are continuing to be sustained?

For example, if you did a sensitivity study and you did varythings by a factor of 4, how do you know that all those RISC-3 components were still within that envelope? And then we got into a discussion of the word degradation mechanisms need to be considered and right now it's not clear that within our guidance and clearly not within our rule that the word considered known degradation mechanisms up front is actually any of our rule or the guidance. And I'm going to -- Tom Scarboro has got an example he gives of - and I've got to give him credit, but I got it third hand, so if I don't say it right, Tom, jump in, is if you have valves, a lot of samll valves that have grease on the stems and they are in a steam tunnel and you're going to get hardening of the grease, that's an environmental condition that needs to be considered in all aspects of what we now have in the rule where we've got monitoring and all those different paragraphs. And yet we haven't necessarily written in the rules the idea of considering environmetnal conditions. So we're grappling with that right now. And I'm going to suggest that that's my connection to

50.55(a) which is a mechanism right now within our requirements that tries to grapple with assuring that continued reliability. So what we're trying to do is get to the roots of how do we say that. We don't have it righ tnow.

CHAIRMAN APOSTOLAKIS: It's something that woudl be --

MR. GILLESPIE: WE've got it on the table. I'm not sure qyite how to do it, and do it without superimposing just a bevy of QA requirements on the PRA and decision process also. I mean in my mind I've got to keep, we've got to keep this as a staff in perspective. We are delaing with low risk components to the greatest degree possible. We hope we have a credible process, but how do you check that your process was carried out the way you thought it hsould be.

MEMBER SHACK: But in yoru particular example, that's an active component. Wouldn't that be covered under the maintenance rule?

MR. GILLESPIE: The miantenance rule is one of the exemptions within 50.69. So that's a special treatment rule that this RISC-3 copmonent would be exempted from. So it's consideration in advance of that to meet the other aspects of the rule,

good enough, or do you need a requirement that says go inspect it every eyar and we're caught between how do we get at the essence of the deterministic go and inspect it every year and the right onctext of kind of a risk-informed, performance-based and we're wrestling with it. Again, I don't know the answer.

CHAIRMAN APOSTOLAKIS: I undrsatnd.

MR. GILLESPIE: I think we've got the question.

MR. REED: Saying it a little bit different way, when you look at whether you feel comfortable with this process going forward as an NRC, a regulator, you look well, what, whwere were the requirements reduced, so that focuses you down on RISC-3. That's where we removed ruqirements. Everything else, we're keeping requirments and putting more on. So I look down at Box 3 first and say what could go wrong there. Well, what could go wrong there is obviously they could degrade over time. YOu could lose either functionality or you could go outside the bounds of your sensitivity analysis. How do you fix that? Well, then you look at what's the feedback mechanism. So you can see how our logic works to try to get to the exact sisue you just brought up and maybe we can do it in a performance based manner

that's consistent with the principles of Option 2. I don't know. We're wrestling with it.

MEMBER BONACA: On the issue that you raised regarding how do you know, okay, one comfort we got from SDP was that they claimed that for each component that was in a certain category there was a full document description of how they got to that particular based. So therefore, one could envision that you could have an audit to understand how it was applied and there was -- I didn't understand that this would be a requirement under the NEI document. Traceability wasn't clear there to me.

MR. GILLESPIE: Yes, and that's part of what I said. The guidance document is a work in progress, and in fact our thoughts are actually evolving even right now as people are putting these issues, like the valve in the steam tunnel, or there's RISC-3 and there's RISC-3. Which 3 is the spectrum, and you draw a threshold. But as you get closer to the top end of that threshold, the sensitivity study actually takes on more importance as to whether you're within the threshold or not.

How do you that in rules space and in guidance space without overburdening a system? It's a compromise to some degree. We're wresting with

that, and that's why I think we're going to actually have some more interaction with NEI on it, because we want them wrestling with us with some of these same questions, and we might not have articulated them the same way in the letter we sent them. Because as we're talking to you and other people, our thought processes are saying how can we get along with this? How can we kind of -- we're focusing in on these specific kind of questions that we might not have -- our thinking might not have been completely clear even three months ago.

CHAIRMAN APOSTOLAKIS: Anything else on this topic? The second bullet there, "Some ACRS Subcommittee members would like studies to perform." I think it's important to make it clear what kind of studies and what kind of analysis we're talking about here. I think there are two categories. One is genetic type of studies. And, again, we're not talking about multi-year kind of things. I mean experienced people can do these things in a short period of time. But generic kinds of studies that can support various approximations or assumptions that are being made routinely, and NEI 004 articulates those, what is being done. I don't expect that if one does these studies, the basic approach will be really upset too much.

But it seems to me that we ought to be doing things that we understood very well. For example, this issue of uncertainty in importance measures. Frankly, I don't think it's going to be a big issue, but I would hate to have the only evidence that I have come from a professor and a graduate student somewhere who did something six years ago. Can we make sure that we understand that this is not an issue? And how long will it take to do that? I don't think it's going to be a long study, and this is kind of generic. It's not something that every licensee will have to do later.

Now, speaking of what the licensees will have to do, I don't understand why -- I mean, I agree with you that the sub-bullet there, parametric as well as model uncertainties, the real issue is really model uncertainty here, not the parametric. And yet we're mixing the two. We know -- I mean if there is one thing we know now is how to handle parametric uncertainty. And it's easy to do, to propagate. But still the document ask that this be done. It plays with sensitivity studies that it's not clear now which part of the sensitivity study addresses the model uncertainty, which part addresses the range of the parameters of lambda and so on.

Some of this stuff, it seems to me, can become much cleaner and more convincing. And, again, I don't -- I think it's going to be of great value to the independent panel. It really will be. In fact, in our letter of three years ago, we said that one should do studies of this type, and then the insights that will be gained -- let's see how we put it. Now, at that time we were looking at Appendix T, but "The guidance to be provided in the proposed Appendix T for the Expert Panel should include insights gained from the implementation of Recommendation 4 above, which was really doing all these studies that I just mentioned."

And that I see as an essential part to making sure that the whole process is on solid ground. In other words, just because somebody's an expert on plant systems I'm not sure he's really qualified to use fussell vesely and RAW without any other information to categorize things. I mean, we need a combination of types of expertise here to come up with a reasonable product for the same reason that I wouldn't trust a guy who understands RAW and fussell vesely and never been to a plant to do this categorization. Should you have some --

MEMBER POWERS: But I mean isn't that

fairly a hypothetical thing? I mean who is going to be involved in a categorization process that only has fussell vesely and RAW data only?

CHAIRMAN APOSTOLAKIS: We should take PRA guy who has never really been to a plant? I mean, I don't think would be a proper member, but that's not my point here. My point is that when you're presenting the results from the PRA using RAW and fussell vesely, to what extent should you train the Expert Panel, or educate them, as to what these measures mean, limitations perhaps, and so on. It's like the expert opinion thing that was done for the --

MEMBER POWERS: Well, I think that's the point is that it's the limitations on these measures. I mean nobody's going to use them with no other information. You simply can't. I mean, it's just not physically possible to close your mind to other information.

CHAIRMAN APOSTOLAKIS: No, no. That's not what I meant. But I mean --

MEMBER POWERS: No. I think your point that the limitations of these things are not well appreciated.

CHAIRMAN APOSTOLAKIS: Right.

MEMBER POWERS: And they are severely

limited, and it's the one of time variation that's the principal limitation, to my mind.

MR. PARRY: George, I'm not sure that the members of the IDP necessarily to be looking at the RAW and fussell vesely values themselves. I think that they would be looking at the overall results of the categorization that would have been performed PRA analysts that would have taken into account all these uncertainties about fussell vesely and RAW. I mean it's not clear to me that they need -- that the IDP needs to actually understand what a RAW is.

CHAIRMAN APOSTOLAKIS: If I were them, I would like to understand.

MR. PARRY: But that's not the only thing that goes into the categorization that they're going to be presented with. There's a whole slew of --

CHAIRMAN APOSTOLAKIS: But it's a major input, though. It's a major input.

MR. PARRY: It's an input. I'm not sure it's that major of an input. It's the starting point for the categorization.

MEMBER POWERS: Well, I mean even if it's just that, even if it's just the starting point for the categorization, then I think it's important to understand the limitations on that starting point.

MR. PARRY: Yes. And I think the process recognizes the limitations on the starting point and compensates for it by requesting some other additional studies. In particular, it also requests the valuation of delta CDF and delta LERF.

MEMBER POWERS: Well, I think the concern is that the choice of those augmenting studies that you speak of here, the additional information, requires some substantial understanding of what the limitations of the fussell vesely and RAW numbers are.

MR. PARRY: And shouldn't that be a part of the process NE 00-04 that recognizes those limitations and designs the process to compensate for them?

MEMBER POWERS: Yes.

MR. PARRY: And that's what it tries to do.

CHAIRMAN APOSTOLAKIS: But the point is that the Expert Panel also should become aware of these at some level anyway. You don't want them to become expert but at some level.

MR. PARRY: I think that might involve a quite considerable amount of PRA training if go through all that.

CHAIRMAN APOSTOLAKIS: Well, I don't know

about that. You know, you can -- I'm not sure that's the case.

MR. CHEOF: I guess let me add something. I guess in the current NEI 00-04 guidance and in the IDP that we have observed so far the IDP members have been pre-trained in a one-day PRA training as to the results they are getting and what they mean, and I guess, like you all say, the limitations of the PRA. I am not sure that the training includes things like the uncertainties in terms of parameters and models. And perhaps the models might get -- the modeling uncertainty might get mentioned in the fact that these initiators are not modeled and we will account for these initiatives this other way using this flow chart, for example, in NEI-00-04. But there is training for the IDP members, for all IDP members, and that training does include importance measures.

CHAIRMAN APOSTOLAKIS: I don't remember that, but if there is, fine.

Now, you guys agree with the NEI, at least the version we saw, that it's good enough to use so-called point values and then do sensitivity analysis?

MR. PARRY: In general, yes.

CHAIRMAN APOSTOLAKIS: Even when you calculate delta CDF, which is a very small number?

MR. PARRY: Well, going back to --

CHAIRMAN APOSTOLAKIS: And why do it that way? What do you say? Is it a big deal to do it right?

MR. PARRY: Actually, for some people it may be. But then that's just a technical issue on the codes.

CHAIRMAN APOSTOLAKIS: For some people.

MR. PARRY: It depends on the quantification code you have, George. Some of them are not set up to do the proper state-of-knowledge correlation on uncertainties, and you have to do that.

CHAIRMAN APOSTOLAKIS: Maybe they shouldn't then be following Option 2.

MR. PARRY: No, no, no, no. Because what it also -- we address this issue also in Reg Guide 1.174. We had the same issue. And what we said there was you should do it by propagating uncertainties to get the correct mean, but you could also -- if you could demonstrate, by reviewing the cutsets, that in fact this impact of the state-of-knowledge correlation was not significant, then that would be another way of demonstrating that you got close enough to the mean value. Because that's the only thing that changes the mean value from using input mean value as a point

estimate in all the calculations.

CHAIRMAN APOSTOLAKIS: No, no. It's not the only thing.

MR. PARRY: I believe it is.

CHAIRMAN APOSTOLAKIS: When you propagate point values, don't you need the values?

MR. PARRY: No.

CHAIRMAN APOSTOLAKIS: Yes.

MR. PARRY: No. Not with cutsets, you don't. Only if you have correlated variables.

CHAIRMAN APOSTOLAKIS: The early PRAs were done that way. I did it by hand, and you have to use the variance too. The expressions for the mean involve the variance.

MR. PARRY: If you are multiplying together basic events that depend on the same parameter for their probabilities, yes, you have to propagate the variance, but otherwise the mean translates. If they're totally independent variables, it doesn't matter if you add them or multiply them, it's the mean value.

CHAIRMAN APOSTOLAKIS: Anyway, we don't need to debate that now, but I don't think you're right. I think to propagate the nth moment, you need the N plus one moments.

MR. PARRY: You don't need the nth moment if --

CHAIRMAN APOSTOLAKIS: Well, you need the first one; therefore, you need the second too. But the point is that even though the -- by and large, you're right, the number will be close enough.

Wouldn't the sensitivity studies be more meaningful if you had such a baseline analysis to do them, rather than playing with the point values and, say, "I multiplied by two and I will go now to the 95th percentile." What's the basis for all this?

MR. PARRY: I think you'll find in the latest version of NEI-00-04 that you were looking at, certainly as far as the independent failure rates, that taking them to the 95th percentile and the 5th percentile's been taken out. The parameters that are varied in that way are things like common cause failure parameters and human error probabilities.

And the reason I think they're put in there that way is because we know that those are pretty uncertain values, and what we want to do by doing those sensitivity studies is to make sure that either -- the importance of certain components has not been either inflated by using pessimistic common cause failures value or deflated by using very optimistic

values. It's like a safety net, if you like. And I think that's the reason for it being there, and I think it is informative to do that.

CHAIRMAN APOSTOLAKIS: And how will you know that the point values that they will use will be the mean values?

MR. PARRY: Because they've been declared to be the mean values. And I think you'll find that that's a lot of the way things were done in the past and it's historically. But those point values are probably chosen from generic -- for a start, if they were point values and purely point values, they would probably have been got from generic estimates. And I think most people, in choosing the values, would have chosen the mean value of any generic estimate. And if it's a --

CHAIRMAN APOSTOLAKIS: So, in essence, what you're arguing is that we should forget about the additional uncertainty analysis, because it doesn't really matter. I mean that's what you're saying.

MR. PARRY: That's not quite what I'm saying.

CHAIRMAN APOSTOLAKIS: Well, when does it matter then?

MR. PARRY: I'm saying that you don't

necessarily need -- that you can survive without doing it.

CHAIRMAN APOSTOLAKIS: The document was very clear that you don't need it. It didn't say necessarily.

MR. PARRY: We all said it's preferable to do it.

CHAIRMAN APOSTOLAKIS: But you should have some benefits when you do it.

MR. PARRY: If there is indeed a major benefit to be obtained from it. And that's perhaps one of your studies.

CHAIRMAN APOSTOLAKIS: Well, I mean one of the goals of the Commission is to inspire public confidence.

MR. PARRY: Yes.

CHAIRMAN APOSTOLAKIS: Also doing things right has to have some value.

MEMBER POWERS: Well, I don't know that doing it right, but calling something a mean value that isn't a mean value does not sound very confidence inspiring.

CHAIRMAN APOSTOLAKIS: That's right.

MR. PARRY: But there is -- I think for very many of the parameters it's actually quite

difficult to get the generic distributions. And I can give you an example. A long time ago, I was involved in an exercise to generate a database, a generic database for ASEP. The way it went was that everybody voted on what value they should use for the parameters, and they said, "Okay, what uncertainty should we put on this? Put down a factor of three or should we put ten?" And that was a vote as well. And that's how some of these old, generic databases were generated.

Now, it turns out, actually, as data is being collected that they were not all that bad, and as more and more people have done data collection on their own plants and updated the distributions using the Baysian methods, they haven't found that the mean values, in general, have strayed too far from those originals.

CHAIRMAN APOSTOLAKIS: My experience has been different. In some plants, their operating experience did indeed change the mean values.

MR. PARRY: There will be some specific cases, yes.

CHAIRMAN APOSTOLAKIS: But were the IPEEEs done that way? I mean did they use --

MR. PARRY: They're all over the map.

CHAIRMAN APOSTOLAKIS: -- mean values that --

MR. PARRY: They're all over the map.

CHAIRMAN APOSTOLAKIS: They're all over the map.

MR. PARRY: Yes.

CHAIRMAN APOSTOLAKIS: So how do we know that these will not be all over the map as well?

MR. PARRY: I think one of the things that we're proposing to put in our view guidance with the staff is that indeed the parameter value should be compared to well-documented generic databases to see if they are significantly different.

CHAIRMAN APOSTOLAKIS: But it seems that the reason why you're arguing that way is because some people might have difficulty doing it rigorously. So why don't you then say, "This is the rigorous way of doing it, and if you don't do it that way, you do it another way, you also have to do something else, so there is a penalty"? And that's fine.

MR. PARRY: But they do have to do something else.

CHAIRMAN APOSTOLAKIS: The version we saw did not ask for uncertainty propagation at all. It just said --

MR. PARRY: Right.

CHAIRMAN APOSTOLAKIS: -- these are the point values.

MR. PARRY: But in calculating the delta CDF.

CHAIRMAN APOSTOLAKIS: It didn't say anything there either.

MR. PARRY: Maybe it didn't, but -- well, I can't defend the NEI document in that regard, but --

CHAIRMAN APOSTOLAKIS: I mean when we calculate the difference of two very small numbers, are we arguing that uncertainty doesn't count? I mean, boy, that's really -- when you calculate delta CDF and delta LERF, has anybody demonstrated that if you work with mean values, you get a reasonable difference when you're talking about ten to the minus six and seven? I don't know. Because as we know, the uncertainty increases, right?

MR. PARRY: Again, I think you can -- by reviewing the cutsets that drive those deltas, you can see whether there's likely to be a difference. That's the extra work you have to do to show it.

CHAIRMAN APOSTOLAKIS: One of the papers that was published in '68 by Allen Cornell, that was one of the first papers that showed that probablistic

methods can indeed give you counter intuitive results, had this example in it. You have the difference of the stress minus the strength, you have some uncertainty in each, okay? And the variance of the difference is in fact the sum of the variances, which is kind of counter intuitive. It increases the uncertainty. The difference of the means -- I mean the mean of the difference is the difference of the means, and everybody says, "Yes, big deal. I knew that." But the uncertainty increases by how much, and the variance is the sum of the variances.

So now we are calculating these delta CDFs and delta LERFs that are such small numbers, and this morning we saw ten to the minus seven, and we are completely ignoring these subtleties, if you wish, of the methods. I mean somebody has to demonstrate that it doesn't matter, if it indeed it doesn't. I don't know.

So even if we accept the premise that point values, mean values -- the declared means values really don't matter when you do the baseline calculation using fussell vesely and RAW, when you go to the delta CDF they still don't matter, the uncertainties? I mean when you're now calculating differences of very, very small numbers? I don't

know. I'm not saying it does, but can someone show me some evidence that it doesn't matter?

And I think it's the same thing as we were talking about the availability or unavailability of PRA. If you have a PRA, your life should be easier using fussell vesely and RAW and all that stuff. If you don't, then your categorization process should be much more conservative, right?

MR. PARRY: Yes.

CHAIRMAN APOSTOLAKIS: I mean is that evident in NEI 00-04? I don't know.

MR. CHEOF: We think it is. We have made that comment before that, you know, if a licensee has a PRA for an external event, that they can be less conservative, and if they were to categorize using a method that's not PRA quantified, they have to be a lot more conservative.

CHAIRMAN APOSTOLAKIS: Yes. We can agree that that's the way it should be. But does the document do something that guarantees that this will happen?

MR. CHEOF: I think there's at least one statement in there that says that. I'm not sure if the process itself --

CHAIRMAN APOSTOLAKIS: Oh, okay.

MR. CHEOF: I mean they do have flow charts in there and how they can treat the other external events. And the staff has looked at those flow charts, and I think we are working with NEI as to how we can ensure that those flow charts will indeed give you more conservative results than if you had a PRA.

MEMBER KRESS: Let me ask what might sound like a strange question. This process of recategorization of SSCs is -- the view, seems to me, we've got to already have a categorization. That's the reason we end up with four categories. And that the process is going to be applied to plants that have already categorized and we're just going to recategorize. Can the process be applied to a brand new plant that comes in and says, "I haven't categorized yet."

MR. REED: Yes.

MEMBER KRESS: Do they have to go through the old process first and categorize and then --

MR. REED: Yes.

MEMBER KRESS: So is the old --

MR. REED: I think they would have to.

MEMBER KRESS: So the old process would be part of the overall process.

MR. REED: Obviously, this hasn't happened yet, and so it's going to be a little bit of a speculation on my part, but if somebody was to, today, decide to apply for a new license and follow the current Part 50 and then try to adopt 50.69 in the process, I think what they would first have to do is basically go through like the old design basis, safety-related world --

MEMBER KRESS: They have to go through the whole design basis.

MR. REED: Do that on paper now.

MEMBER KRESS: Yes.

MR. REED: And then basically do a categorization, and then take that whole safety-related and non-safety-related world, translate it into the four boxes, now all on paper, come in basically with that submittal, and they would procure from the get-go Box 3 to be RISC-3. So they would -- right from the start the whole plant would be procured that way. That's a big difference versus current facilities.

MEMBER KRESS: Yes. That's my impression of what would have to be done.

MR. REED: That's correct.

MR. GILLESPIE: Yes. On the other side,

if it's a certified design, the certification is, in and of itself, a rulemaking. And so someone who has a certified design could apply the concepts of Option 2 likely within the context of the certification. So Tim described someone who would be coming in applying for a license under the current Part 50 as if they were 20 years ago. Yet we have a different process which might actually allow a little more freedom and innovation. Because a rule can offset a rule.

MEMBER KRESS: Yes.

MR. GILLESPIE: And the certification itself is a rule.

MEMBER KRESS: I understand.

MR. GILLESPIE: I think that's how we'd end up getting around this without rewriting all of Part 50 again.

MEMBER KRESS: Yes.

CHAIRMAN APOSTOLAKIS: I can give you an example from this morning's presentation of abuse of PRA models, and only if you really have seen a lot you appreciate it. We were told that the time to respond to something was reduced from nine minutes to six minutes. And there was a table that said, "and the core damage frequency increases by less than one percent." Now, Gareth, you don't believe that, do

you? You know that it can't and on the face of it is a misleading statement. Are there any models -- any reliability models that can really tell the difference between a nine-minute response and a six-minute response, and everybody agrees that, yes, that's true? I mean there are ideas, there are judgments, there is this, there is that, and yet it was presented this is what it is.

Now, the application was not risk-informed so it didn't matter, but you see that my point is that somebody who knows will look at this thing and say, "What's going on here? This is really nonsense." But it's not essential to the decision, so you let it go.

MR. REED: I think I'll just add a comment; hopefully it's constructive. But I think some of the issues you bring up are why in Option 2 space why we're risking forming only assurance requirements and maintaining the design basis down in Box 3, albeit with less assurance.

It almost -- I'm not saying I know what you think, but sometimes I get the feeling that we're trying to justify significant technical changes here, and I think you'd have to know a lot better some of these uncertainties if you were trying to make technical changes to the facility. At least that's my

own personal opinion; perhaps you don't. But in Option 2 space, in think we get some comfort from the fact that we're going to be maintaining the design basis functions.

CHAIRMAN APOSTOLAKIS: The problem is that when we start using PRA in real decisions, we seem to be going backwards, and we seem to treat methods and models in a cavalier way. You know, you want the delta CDF involving time-dependent human errors? I'll give you one. Okay. And everybody says it's one percent. I mean when in fact the answer is there are ten different models out there, and you can get any answer you want. And the truth, in my mind, is that you can't really quantify such a difference, I mean, with any degree of confidence at this level.

I mean you know that it's a good thing. It's actually a bad thing in this case because available time was decreased by a little bit. But you can't really put a number. But if you keep doing it that way and you never really raise the flag and so on, eventually it will become practice, and that's bad.

MR. PARRY: Well, I think though, George, in that particular example, I think it's incumbent upon the reviewer to figure out what model's been used

and whether if they used alternate models if they'd get a different answer. And that's part of --

CHAIRMAN APOSTOLAKIS: And why isn't that applicable here? If you use a different model, you may get a different answer.

MR. PARRY: I think that there are -- I mean at least in one of our comments, one of the things we said was that you should identify the assumptions that drive the changes, and they should be candidates for performing sensitivity studies --

CHAIRMAN APOSTOLAKIS: That's right.

MR. PARRY: -- to see whether they impact the categorization.

CHAIRMAN APOSTOLAKIS: I guess we're talking about two different things now. You're referring to comments you have submitted to NEI, which I am not aware of.

MR. PARRY: Right.

CHAIRMAN APOSTOLAKIS: And I'm referring to NEI 00-04, the document I have viewed.

MR. PARRY: I know. And one of the things in 00-04 is if you look at the sensitivity studies that are specified, they do have a category there which are those that I think that are revealed by the facts and observations from the peer review process.

So that gets part of the way to where we want to be, but I don't think it gets all the way there.

CHAIRMAN APOSTOLAKIS: Anyway, shall we go on?

MR. REED: Sure.

CHAIRMAN APOSTOLAKIS: Unless there are other --

MR. REED: Anymore questions on this slide? Okay.

So continuing with two more key points then, one of which has been made several times already today, NEI 00-04 is an interim product, it's in a state of flux. It's certainly going to change. NEI's going to update it and roll back in the feedback they've gotten from pilot activities and also address our comments. And it's understandable and of course appropriate that ACRS would reserve its final judgment until they have a more final product. So that's all this slide simply reflects.

MR. GILLESPIE: I think, George, part of the discussion this morning has highlighted why it's a work in progress. Fourteen pages of comments, and I forget how long NEI 00-04 was, but I think it was only -- Tony, help me out, about 30 pages long?

MR. ULSYS: Categorization piece --

MR. GILLESPIE: Categorization piece.

MR. ULSYS: -- was 17 pages long.

MR. GILLESPIE: Okay. So we've submitted comments that are in excess of approaching 15 percent of the total document. And we need to see how it now comes out of this next step in the process and have another iteration. I'm not promising that everything you've said will be considered, but I think the idea of assuring the applicability of the study to what we're using it for, the need to do that is a concept that we will be trying to embody in it.

I don't know how to do it, and there's been discussion that's over my head on how to do it, but I think we understand the comment and have some sympathy for it. Now, we have to figure out is how to articulate it where it's consistent with what we think are low-risk components also.

CHAIRMAN APOSTOLAKIS: The way I see it, Frank, is you have to make approximations, you have to. I mean that's the way life is. If you do, it seems to me, somewhere there you have to demonstrate that it's an approximation, rather than saying, "Well, we've done it many times, and it came out that way."

The other thing is I think it would be useful to say, "Look, if you do it this way, in a

rigorous way, this is the benefit you get. If you do it in a less rigorous way, you should be a little bit more conservative, and this will guarantee that that's case. And typical example here is when you have a PRA or you don't. A guy who has a PRA for fires, for example, should be able to get more benefit out of it than somebody who did five, right?

MR. GILLESPIE: Yes.

CHAIRMAN APOSTOLAKIS: Or the seismic Heathcliff, whatever they call it, or rigorous PRA. And then when you go to the places where there is no PRA at all, then you make sure that you have a conservative approach. So this kind of phased approach, I think, would go a long way towards convincing me, at least, that this is a good, solid approach.

MR. REED: I think everybody agrees with that concept, and I believe we are trying to assure that's in this guidance document.

MR. GILLESPIE: Yes. In fact, I'll say it a little different way. What the staff would like to do is give people who have gone that extra mile to do an external event PRA in some detail or shut down PRA in some detail or fire analysis, we'd like them to be able to maximize the benefit they get from their

investment.

CHAIRMAN APOSTOLAKIS: Exactly.

MR. GILLESPIE: So in principle, we're in total agreement. And right now, though, we're trying to endorse what -- I could generalize, this is a generalization -- a one-size-fits-all kind of guidance document. And what you're saying is when you read the guidance document, you didn't see the spectrum that would actually encourage people to do the right thing because of the benefit from it.

CHAIRMAN APOSTOLAKIS: Exactly.

MR. GILLESPIE: So I think I got -- I know where you're coming from and we're in total agreement, but the staff being in agreement doesn't mean the industry who's writing the industry guidance is necessarily writing it with that same concept in mind. We can give them the comment and they're here. If they heard the comment. But how they embrace that comment, we're going to be reviewing for the purpose involved, whatever they submit. But I think it's a valid comment. And, indeed, in disk space and risk-informed tech spec space, we would also, in a risk-management sense like to give people the maximum payback for what they've invested and what should be a better decision tool.

How do we get there? We haven't figured that out yet. You know, it's difficult. As a regulator you can't dictate that to somebody, but we would hope the industry would kind of grasp that concept and maybe figure out how to factor it into their document also.

A mutual gain on that, because there is a spectrum of facilities out there with a spectrum of tools available. And how do you give that guy who's put a big investment in the maximum return, and that's really your question, versus writing a guidance document to the median level? It's a fair comment. Tony, you've got the comment.

MR. PIETRANGELO: We'll wait our turn.

MR. GILLESPIE: Okay.

CHAIRMAN APOSTOLAKIS: Well, are there any more questions for the staff?

MR. REED: I guess I'd just like to say on this last slide, it kind of rolls everything up, I would simply mention that, probably said already, I think we've said everything here, but if the Committee has major issues, then we'd like to have a letter, and we certainly appreciate the Committee's input, and it's obviously a great deal of expertise in the PRA on this Committee, so appreciate that.

MR. GILLESPIE: And I hate to say it, this being March and our rule due in July means we probably need a letter in June. So it gives us about 30 days to get you something for potentially an April or May meeting.

MEMBER POWERS: We're not that slow.

MR. GILLESPIE: No, but we may -- just in counting back, if we're trying to get something to the Commission and we need a letter by July, I'm not sure that we might not have to have something to you so that you can read and review it for a June meeting. Which may mean, I don't know, a May Subcommittee meeting.

So, anyway, we're going to be back again. I'm anticipating, George, that we'll probably have another Subcommittee meeting and full Committee meeting.

CHAIRMAN APOSTOLAKIS: Yes. That would be good. When you say that the staff requests a letter, you mean now, this letter you are --

MR. REED: Yes. The letter I'm asking for right now if there are major issues that -- I'd like to be able to --

MR. GILLESPIE: Yes. We're going to have to come back again for a second letter. So the

context of this letter is we're really having a dialogue now and we're looking for suggestions, advice and anything you want to give us. We'll be back again for another letter.

CHAIRMAN APOSTOLAKIS: The two letters that I mentioned that we have already written they still stand.

MR. GILLESPIE: Yes.

CHAIRMAN APOSTOLAKIS: Okay?

MEMBER SHACK: Just coming back to your degradation problem for a minute, isn't part of that an artificial thing where you insist on -- or at least the guidance sort of gives all components the same increase in failure rate. If you really went through and you said, you know, "A valve and a steam tunnel, if I don't have the special treatment, it's failure rate may go up X a valve sitting out in a benign containment environment."

MR. GILLESPIE: Well, exactly, and that's why --

MEMBER SHACK: And it seems to me that that might be a sensible place to begin to attack that kind of a problem. I think we're going to have to go to sensitivity analyses, but I'm not sure that -- you know, the broad X approach that's been chosen at the

moment really, I think, penalizes the industry to a certain extent.

MR. GILLESPIE: And that's something we just really started coming to grips with, because it's kind of an overriding consideration for all those paragraphs we've got in the rule for monitoring and conditioning and all those different things. So it's kind of an -- there's a sentence in there someplace that we might not have right now that says, "Consider this when you're doing these things."

We're not saying hide a monitor, but clearly monitoring of these components, whether it's needed or not in that decision, the intent is to maintain the credibility of the decision process that you made when you made your decision on what you needed to do or the decision that it was RISC-3. How do we sustain the credibility of the decision process, both in the beginning and as an ongoing basis? We're wrestling with that right now. Because you would penalize people. If you make a blanket statement, it's like, well, we're going back to the old way of doing things. So we want to leave some flexibility in there.

MEMBER SHACK: Okay.

MR. GILLESPIE: Thank you. I think that's

it for the staff.

CHAIRMAN APOSTOLAKIS: Thank you very much. Tony? Welcome.

MR. PIETRANGELO: Good afternoon. I'm joined by Adrian Haymar and Biff Bradley from NEI. We wanted to -- we were primarily going to talk about the categorization guides today, and I know you had a Subcommittee meeting where you got a pretty extensive presentation on that guidance. We're not going to redo that today, obviously.

What we did want to talk about, though, and I think Tim set it up quite well, this is a work in progress. We have your comments, we have the staff's comments. We think we have a comprehensive guidance document for this categorization. Before we began the pilot categorization effort that began last fall, I think we had a critical time last July with the staff to make sure there were no show stoppers in the guidance that would preclude the pilots from trying to demonstrate the usefulness of NEI 00-04. We got to that point. I'm sure there's additional comments that can be incorporated.

I think Tim captured the issues we're working on quite well, in terms of addressing the late containment failure and the IDP guidance. I think the

peer review piece is a separate issue. Quite frankly, that applies to all the PRA applications. We have an entirely separate effort dealing with that. We met with the Office of Research last month on the guidance to endorse both the ASME standard as well as our peer review guidance, so that's going in parallel with this. Certainly, this is one of the most important applications that exercises all elements of the PRA.

One thing I do want to point out where we are in kind of our stage of development here, and this issue has come up and we've talked about the ASME standard and PRA quality, in general, this is an evolutionary process. I think if we get too hung up with the level of precision about where we are today, I mean that stops progress. That's why we've been, I think, pretty adamant from the outset on here that there's a need for NRC staff review of any Option 2 application.

We didn't buy the Appendix T concept of you raise your right hand and swear that you meet all the stuff that's detailed in Appendix T and then the staff doesn't have to review it. We're not in the stage of development with PRA and the comfort level yet to do that. And we were glad to see the staff pull that out of 50.69, because, again, that's a nice

goal to shoot for maybe in five or ten years when we do have added confidence in the studies, but we're not there yet.

So if Gareth or Mike or any other NRC staff reviewer has a particular question about what the licensee did in the Option 2 application, they can ask the question in the process. We still intend to define a template, just like we did -- we're using risk-informed ISI as a model for this, a template of what the licensee would submit as part of an Option 2 application.

So I think the process -- that's another part of the process. We've tried to follow 1.174. That has worked quite well. I think some of what I gathered from the discussion this morning, George, is that we're starting reopen some of the things that were discussed when 1.174 was developed. And I think in the context of an application, that's not the time to do it. It should be done independently of the application.

We think sensitivity studies were one of the things that 1.174 said you could do to address areas where you have uncertainties. And that's what we're doing. So we're trying to follow the guidance that's out there that's been successful, and not try

to reinvent that, with the Option 2 guidance.

Your Committee spent a lot of time on 1.174. All those issues were debated quite thoroughly. And to reopen that as we go through this process again, I'm not sure is the most --

CHAIRMAN APOSTOLAKIS: Well, and I would have to be convinced that I'm reopening issues. I'll go and read 1.174 again, but lets go on.

MR. PIETRANGELO: Okay. The other thing we wanted to briefly chat about today is the treatment, and Frank teed up some of those issues. I mean to us we've been talking about treatment I think going back to graded QA now for almost ten years. And it continues to bewilder us that the focus of the reviews are on the low safety significant SSCs. That's not what risk-informed regulations are all about. That's what we see all the hand wringing about just about in every application we get into. And it's like each application, before we get to the end of it, it seems like the entire regulatory process has to be dumped into this one application, and we forget about all the other things that are at play out there.

Besides the revised oversight process, there's requirements in the rule that the licensee has to meet, all right? And they're subject to inspection

and enforcement. And if they don't do what they said they were going to do, then that's willful non-compliance, and the staff knows very well how to deal with willful non-compliances.

So I mean we have to remember there's whole other regulatory construct around Option 2 that doesn't go away. And we just started hearing about these known degradation -- failure mechanisms and degradations. Well, we know what those are. They don't go away when we go to Option 2. If a valve or any other piece of equipment goes into the preventative maintenance program, you don't forget about all the other stuff that happened to it. All that operational experience is still there.

And so NRC can audit the implementation of Option 2. They can audit the performance monitoring that goes on with Option 2. Most of it's already captured in the maintenance rule.

And the other thing, you know, the industry has experience with categorization, even before the maintenance rule with some of the MOVs and a graded QA application. So we've been doing categorization for a long time. Let's demystify what's going on here. I mean this is not going to hinge on some number in the PRA as the one thing going

up or down. I mean to even suggest that that's happening through this is absurd, okay? The Expert Panel there's guidance in our document now that talks about the requirements for the Expert Panel, that's similar to the folks that are around the table here, okay?

So, again, to get tied up in the level of detail and the PRA calculations and all that, we want to do a good technical job, I'm not here to say otherwise, but unless it has an impact on the result, then we can spend an awful lot of time in the noise level of this and not get to the fundamental purpose of it, which is we've been categorizing SSCs for a long time, we have a very comprehensive process we're trying to develop and get the staff to endorse, and your endorsement, and give the best guidance we can to the licensees who wish to go into Option 2.

And the short answer to your question that you posed at the end, if they don't have a sound technical basis from which to defend moving the thing down from RISC-1 to RISC-3, they're not going to do it, because they're going to be subject to the NRC's review, and if you don't have an argument, you can't just wave your hands at it and say, "Now, it's RISC-3." There's an extensive process to go through, both

PRA and other studies done, as well as the Expert Panel review, and that will be subject to the staff's review also. We have to put faith in that process.

And even afterwards in implementation, if there's new information that comes to the table, there's mechanisms to treat that, just like there is with any other regulation. And how do you know we're implementing a(4) from day to day, how do you know we're doing 50.59 right from day to day? So that whole rest of the regulatory process is there to bring those up again within this context. I mean we've all been in this business a long time, and to wring our hands over that kind of stuff at this point just seems to me to be a waste of time.

I'm being very candid with you this morning. We've been working on this for a long time, progress has been slow. We've got the last pilot on categorization next week. We'll be rolling that into the next draft of our guidance. We're way ahead of where we are normally on a rulemaking with regard to the development of guidance. In most cases, the guidance document isn't even developed until the final rule is done.

(Laughter.)

We're way ahead of the game on this one.

It's even been piloted already to a certain extent. So remember where we are in the context there. That's all I'm asking.

And we've been listening to the questions back there and we could point out places in the guidance to try to address your questions, but I'll ask Adrian and Biff if they want to add anything to that.

MEMBER POWERS: In thinking about things to add, I guess this philosophical issue that George brings up on rigor in the use of PRA, I'd be interested in your comments on that. You've already addressed it somewhat. But I guess what I'm interested in is the desirability of having a nice rigorous treatment with respect to PRA, understanding that the PRAs that we have today bear faint resemblance to the PRAs we'll have in ten years or 20 years.

MR. PIETRANGELO: Right. We want them to be rigorous, we want it to be a repeatable application, we want to have some stability in the process. We're all for rigor, okay? But if you don't have the study for a particular scope element of the PRA, then you've got to use another means. You're not even going to be an Option 2 potential applicant --

MEMBER POWERS: Because you're too far away, yes.

MR. PIETRANGELO: -- right, if you're too far away from that. I mean no one's going to submit themselves to the gauntlet of review here if they don't think they've got a good technical basis from which to do the categorization.

MEMBER POWERS: But doesn't everybody think that because of the IPEEEs?

MR. PIETRANGELO: No. I don't think everybody thinks that. Not to the extent we're talking about here in Option 2. I think for purposes of the maintenance rule when we were trying to establish the level of monitoring that was done, I think the answer to your question was yes. For this purpose, I think this is much more rigorous, and I think we're finding out from the pilots, not only more rigorous but more costly to do and resource-intensive. So unless you're really serious about it, you're not going to do it.

CHAIRMAN APOSTOLAKIS: Anything else? Thank you.

MR. PIETRANGELO: Thank you, George.

CHAIRMAN APOSTOLAKIS: I always appreciate Tony's way of -- elliptical way of making a point. I

would like to thank the staff as well. And we will reconvene at 1:25.

(Whereupon, the foregoing matter went off the record at 12:27 p.m. and went back on the record at 1:27 p.m.)

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

1:27 p.m.

CHAIRMAN APOSTOLAKIS: We're back in session. The next item is the Arkansas Nuclear One, Unit 2 Core Power Uprate. The ACRS cognizant member is Mr. Sieber. Jack, it's yours.

MEMBER SIEBER Thank you, Mr. Chairman. The application and the SER that we're going to discuss this afternoon differs from the previous power uprates that we've had in that this is the first pressurized water reactor that has applied for an uprate in power greater than our cutoff limit, which has been five percent. And so this will be the first PWR that we have undertaken to examine. On the other hand, the staff has done previous uprates of lesser increases in power in the past.

Interestingly enough, the Arkansas One, Unit 2 is a combustion engineering plant, and in the process of deciding what guidance the applicant would use in order to make sure that they have covered all the aspects that are recommended or necessary to do a power uprate, they ended up going to a Westinghouse document, which was published in 1983, and it's WCAP 10263, and that was the basis for the applicant's process of coming up with the analysis and studies

necessary to do the power uprates. And on the other hand, in 1997, the staff did a uprate SER for the Farley Plant, and the Farley uprate was also based on the WCAP that I discussed and mentioned.

And so there is a sort of de facto template out there for the staff to write its SER and applicants to do the analysis for a power uprate for a PWR. Even though the Plant's combustion engineering, there are plenty of similarities between the combustion engineering plants and Westinghouse plants so that these documents are generally applicable.

What I'd like to do now is to introduce Mr. Craig Anderson from Entergy, and he is Vice President of Operations, and he will guide us through Entergy's presentation on the power uprate.

MR. ANDERSON: Okay, sir. Thank you very much.

MEMBER SIEBER Sure.

MR. ANDERSON: Again, I'm Craig Anderson. I'm the Site Vice President for Entergy at Arkansas Nuclear One. We've got several other presenters here I would like to introduce, and if you all would raise your hand in the back. Bryan Daiber is the Senior Staff Engineer that will present a lot of the

technical information today. Rich Swanson is the Senior Reactor Operator that we brought. I think the operational aspects of a power uprate are very important, and we felt like we needed to discuss those. Dale James, the Manager of Engineering Programs and Joe Kowalewski, the Director of Engineering. We also have other folks here, members of our staff, that might address questions that might come up. And also Westinghouse folks here to address any questions that they might help us with.

One of the thoughts might be, well, you're combustion engineering in NSSS, you've got Westinghouse here. If you recall, Westinghouse acquired combustion engineering a few years back, and these folks were previously on the combustion engineering staff, so we've got good technical expertise here to try and address those questions.

Over the next hour, we will discuss the results of years of work to both analyze our Plant and, where necessary, to install modifications to support a safe power uprate of the Unit. You'll see that we were careful to maintain the operating and design margins, and just as importantly to us, to minimize new challenges to the operators. We certainly don't want a power uprated plant that's not

reliable or that presents difficulties to the operators.

Where we weren't comfortable with our margins we modified our Plant, and we will talk about several of those modifications during our presentation. We, of course, used accepted methodologies and we've, in all cases, demonstrated compliance with regulatory and safety limits.

A little bit about the project before I turn it over to Bryan. Our goal is a seven and a half percent uprate. That's where we've completed our analysis to support that uprate. And it essentially was a balance on the financials between the investment that you make in the Plant and the return you get from the investment, and, of course, that without adversely impacting the available design and operating margins.

I think one of the things that's important to point out, the majority of the modifications that were needed to support power uprate have already been made. They were installed during the last refueling outage in the fall of 2000. And we've operated this operating cycle, which ends next month, with those modifications, and the modifications have performed quite well.

The most significant modification was

steam generator replacement. Steam generator replacement, while it was not driven primarily by power uprate, it was driven by the degradation of alloy 600 tubing. We took advantage of the need to replace the steam generators and increased the heat transfer area, both to support power uprate and also give us some more margin.

The rest of the mods, most of them, in the balance of Plant will be installed in the spring, and we will complete all the necessary work for the power uprate, including the start-up testing following the outage to support the power uprate.

So we believe we're prepared for the uprate. We've done a thorough review of the equipment and our analysis and our procedures, and that's been completed. We have been and are continuing to train our operators on the uprated Plant to make sure that they are ready, and we believe our people and equipment are ready.

And let me turn it over to Bryan Daiber who will go through the technical portion of our evaluation. Bryan?

MR. DAIBER: Make sure the microphone's working here. I'm Bryan Daiber. I'm the Safety Analysis Lead. I was the Safety Analysis Lead for

both the RSG and the power uprate projects. I will be going through several of the presentations today. The first one I'm going to go over are the plant modifications for considerations of power uprate.

For ANO2, we've been considering power uprate for the past four cycles. We were obviously considering steam generator replacement due to degradation of the alloy 600 tubes in those. In preparation for that, we were trying to move the copper from the secondary side system, so we replaced the condensers and other major components to do that. And in doing those replacements, we kept power uprate in mind in the design of all those components we've replaced over the past four cycles.

So we have replaced many of the components, many of the major modifications have already been implemented, and we've operated with those for at least one cycle on most of the major components. And as I mentioned, we did keep that in mind, the power uprate was considered for those modifications.

On this slide, we list many of the modifications, balance of plant, and other modifications needed to support power uprate conditions. Many of the major modifications, like I

said, have already been installed and have accommodated for power uprate conditions. Rather than go over these balance of plant type modifications, I'd rather focus in on three key areas, the highlighted ones in blue here: the replacement steam generators, the containment uprate considerations and the fuel core design considerations that we implemented for power uprate itself.

The first key modification, the steam generators. We did replace steam generators last outage. There were degradation concerns with the alloy 600 tubes. When we replaced these steam generators, we replaced them with steam generators that were specifically designed for the power uprate condition. In light of that, when we designed these generators, we did increase the tube sheet diameter by four inches to accommodate greater number of tubes in the steam generator. We also increased the surface area and the number of tubes in the generator by going from three-quarter-inch diameter tubes to eleven-sixteenths diameter tubes. The net effect of these changes allowed us to gain 25 percent surface area on the tubing material in the new steam generators.

The result of that also resulted in an increase in the primary side volume. Now this is key.

The increase in primary side volume did cause a challenge to the containment building pressure. As a result of that, we did have to look at the building pressure considerations. The volume, we essentially went from 1,600 cubic feet to 1,839 cubic feet per steam generator. That increase in volume obviously resulted in an increase in mass of energy available to blow down to containment for our LOCA analysis.

In comparing that to the effects of power uprate, for power uprate considerations on the containment analysis, power uprate results in a slightly higher increase in Tav, and we're also proposing to increase Tcold by two degrees. Both of these effects essentially increase the energy content in the RCS available for the blowdown, but it does decrease the mass available. So really the net effect is the increase in volume had a much bigger impact on the containment pressure considerations than the power uprate considerations.

The other thing on the new steam generators, the secondary side volume also went up as a result of the change. To offset that change in secondary side volume, we didn't modify the steam generators. The new steam generators have an integral flow restricting nozzle in them. This integral flow

restricting nozzle, in combination with high containment pressure actuation signal, the containment spray actuation signal, was sent to isolate main steam and main feed. The combination of those two modifications essentially reduced the peak building pressures associated with the higher power steam line break considerations. As a result, the hot zero power steam line break is actually the most limiting.

MEMBER SIEBER Did you not increase the sprayed area of containment also?

MR. DAIBER: No, we did not -- the sprayed area of containment by the containment spray system stayed the same.

MEMBER SIEBER All right.

MR. DAIBER: So we have designed a new steam generator to accommodate power uprate conditions.

The second key design consideration that we made to accommodate power uprate was, as we mentioned, we did uprate the containment design pressure. We went from a design of 54 pounds to 59 pounds. We accommodate this increase in design pressure by recognizing the fact that the Unit 2 containment is very similar to the Unit 1 containment, although not identical. And the Unit 1 containment is

already designed to 59 pounds.

There was a detailed finite element analysis done to verify the structural capabilities of the containment. That detailed finite element analysis did credit additional tendons. We didn't install additional tendons, but there were -- as part of uprate, but during original construction, additional tendons were put into the containment to account for surveillance considerations and construction considerations that weren't originally credited in the original structural analysis. We did credit those in this analysis to accommodate the increase in design pressure.

Not only did we verify that the structure itself was capable of operating at the higher design pressure, we also verified the equipment inside containment was also able to accommodate the higher design pressure. The containment was tested at 68 pounds to verify its capabilities. All of this work was done obviously as part of the replacement steam generator project and has already been approved by License Amendment 225.

The third key change or consideration with respect to power uprate deals with the fuel core design itself. At ANO2, we are currently using a

Gadolinia integral burnable poison. We are going to switch that integral burnable poison from Gadolinia to Erbia. Now, back in Cycle 13, Cycle 16 being the next core design and it's our operated core design, but back in Cycle 13, we started replacing the poison schims before c-schims with integral burnable poisons, and Gadolinia was the burnable poison of choice at the time. By replacing those schims with these integral burnable poisons, we have effectively gained almost four percent additional pins available in assemblies for additional fuel considerations.

The Gadolinia burnable poison is a much more potent poison, and the typical assembly will have about eight weight percent Gadolinia versus about two weight percent for Erbia. The Gadolinia within an assembly that has Gadolinia pins, they'll be somewhere between four and eight pins, or four and 12 pins per assembly. Whereas with Erbia, we'll have somewhere between 30 to 100 Erbia pins per assembly.

The Erbia is current approved methodology. There are many plants within the CE fleet already using the Erbia core designs. There's essentially over 159,000 Erbia pins already in operation, 64,000 of which have already been discharged. As I mentioned, the Erbia is a more dilute poison, it

allows us to have better power control and gives us better peaking control within the assembly itself. And that helps us out just during normal operation conditions and also as a result of any transient conditions that would occur. It also allows us to have a better control over the moderate temperature coefficient.

MEMBER POWERS: What was the attraction of selecting Erbia as the poison?

MR. DAIBER: Again, within the assembly itself, the Erbia allows for a much more equal power distribution within the assembly.

MEMBER POWERS: Well, I understand that. That's based on the number of pins that you put in there.

MR. DAIBER: Pins and the amount of the poison. Erbia's more at two percent, whereas Gadolinia's more at six to eight percent.

MEMBER POWERS: But you could have just as well have put two percent Gadolinia and put more pins in and done the same thing, couldn't you have?

MR. DAIBER: Jeff?

MR. BROIDA: Use a microphone and identify yourself, please.

MR. DAIBER: I'll let Jeff Brown from

Westinghouse speak to that question.

MR. BROWN: Jeff Brown, from Westinghouse. Another major difference is the cross-section of Erbia. It has about 200 barns cross-section for Erbia compared to, I believe, about 10,000 barns for Gadolinia. Gadolinia, on a per atom basis, is much more stronger thing, and it depresses the local power distribution almost like you had a small control rod there. Whereas Erbia, you know -- so even in a two weight percent concentration, the Gad would have a similar effect as it does not.

MEMBER POWERS: Oh, okay. So you're just avoiding the high cross-section --

MR. BROWN: Yes.

MEMBER POWERS: Sure, I understand.

MR. DAIBER: I'd like to make two major points here with these comparisons of the core designs. The most -- the first issue, which we've already talked about is that going to the Erbia burnable poison allows us to do the flatter power control within the assembly itself. Also, the number of assemblies we're putting in for Cycle 16 it's a larger reload. Eighty new fresh assemblies are going into the Cycle 16 core design. By doing that, we also control the peaking factors, the radial peaking factor

is going down by over seven and a half percent for the uprated core designs. That gives us a flatter power distribution within the whole core itself.

The other important point I'm trying to make on this slide is the energy content. The energy content for Cycle 16 is actually bounded by the energy content that we've already implemented under our current power rating conditions in Cycle 14. The Cycle 14 length was 557 EFPD. For Cycle 16, the EFPD is 485. When converted to a comparable power of 2,815, it's more like 521 EFPD. So it's actually lower energy content. That also can be noticed by the cycle burn-up value. The cycle burn-up for Cycle 14 was 19,770 megawatt days per ton, whereas for Cycle 16, it's 18,825 megawatt days per ton.

I'd like to make two clarifications from the Subcommittee presentation. There was a question asked at the Subcommittee about the fuel zoning. For Gadolinia fuel assemblies, we typically have three zones of U235 considerations. I believe we may have mentioned only one in the Subcommittee presentations. With the Erbia, there are essentially two zones of zoning in the Erbia designs.

The other question that came up at the Subcommittee meeting was with respect to the cycle

burn-ups, and we've just discussed the cycle burn-ups for the different core designs. Yes?

MEMBER BONACA: I had a question, but I couldn't find the answer here. You must have changed your Delta T, T hot to cold.

MR. DAIBER: Yes. Our RCS flow stays the same, so the T hot goes up.

MEMBER BONACA: Yes. Have you changed your pressurizer program?

MR. DAIBER: The pressurizer --

MEMBER BONACA: Program.

MR. DAIBER: Yes. The pressurizer level control system was reviewed and verified and updated as necessary to account for the Tav increase.

MEMBER BONACA: Because some of the early CE five percent power increases didn't, and they used to lose pressurizer level when they were SCRAMing. So you did look at that.

MR. DAIBER: Yes, we did look at that.

With that, I'd like to move on to the next agenda item, which deals with compliance with regulatory requirements, and in particular they deal with the Plant margins. We did review the ANO2 design to make sure it could accommodate the power uprate conditions. We did obviously look at all the balance

of plants, and we made modifications as necessary on the balance of plant to ensure that it could accommodate power uprate within its design considerations.

We also looked at the NSSS, the nuclear steam supply system, which is a CE-manufactured product, and we verified that all the design components there could also withstand the considerations on the power uprate conditions. We also looked at the control systems, the pressurized level control, feedwater control system and all the control systems and made sure that they also could accommodate power uprate. And as we discussed, steam generators containment and the fuel design were also considered, along with all the safety systems.

In the review of any of these systems, in any place where we felt margin was not being maintained as a result of the power uprated conditions, modifications were implemented or will be implemented in the next outage to ensure that all the components could operate satisfactorily at uprated conditions. And for the control systems, appropriate set point changes have been made for those systems.

MEMBER SIEBER I'd like to go back to RSC flow.

MR. DAIBER: Yes.

MEMBER SIEBER During the Subcommittee meeting, it was stated that the replacement of steam generators had a lower DP --

MR. DAIBER: Yes.

MEMBER SIEBER -- on the primary side than the original ones.

MR. DAIBER: That is correct.

MEMBER SIEBER That would increase RCS flow instead of having it stay the same, right?

MR. DAIBER: That is correct.

MEMBER SIEBER And that's why your Delta T change was not as much as you would ordinarily calculate from a seven and a half power increase?

MR. DAIBER: There are several things that went on. Obviously, with the old steam generators we had plugged those quite a bit, and flow -- the delta P had gone up, and flow had gone down. When we installed the new steam generators, we designed those to essentially restore the delta P of the steam generator essentially comparable to the unplugged original steam generators. So flow went back up as a result of that, but it was more due to the plugging -- the removal of the plugging restrictions.

MEMBER SIEBER Now, it would seem right

now with the new steam generators that you have a -- you take into account the fact that I690 has a cooler heat transfer coefficient, so that takes away surface?

MR. DAIBER: That's true.

MEMBER SIEBER Looks like you have a plug of about ten percent. Is that correct?

MR. DAIBER: When we did all of our work, we did it with a ten percent consideration, so all of the efforts that we undertook, we assumed a ten percent plugging consideration.

MEMBER SIEBER And so that -- if I add the eight percent and the ten percent and the seven and a half percent increase in power, that accounts for all the additional surface that's in there.

MR. DAIBER: Essentially, yes.

MEMBER SIEBER Okay. Thank you. Now, I have one other question, going back to containment. What was the containment test pressure?

MR. DAIBER: Sixty-eight psig.

MEMBER SIEBER Sixty-eight.

MR. DAIBER: Yes, 68.

MEMBER SIEBER That's 110 percent of the design. Okay. Thank you.

MR. DAIBER: Hundred and fifteen percent. Right, 115 percent.

One other point I'd like to make is that when analyzed the safety analysis and control system considerations, we are a CE NSSS Plant, and we utilized many of the CE Westinghouse methodologies for performing the safety analysis, core design considerations. These methodologies that we utilized, that Westinghouse utilizes are the same methods used by other CE plants of higher power rating than where ANO2 is projected to go.

As we've discussed, we did install new steam generators. Those steam generators were specifically designed to accommodate power uprate to ensure adequate margin was accommodated in those steam generators. Containment was uprated from 54 to 59 pounds. We installed integral flow restricting nozzle in the CSAS actuation to accommodate the secondary side inventory associated with that. We did have to modify the containment cooling fans. The horsepower requirements in the cooling fans went up above the motor rating at the 59 pound consideration. To accommodate that, we reduced the pitch, we lowered the flow a little bit, brought the horsepower requirements back down within design considerations. To offset that effect, out tech specs only required us to have one containment cooling fan per train. We upped that

to two containment cooling fans per train to offset that.

MEMBER KRESS: How did you increase your design pressure?

MR. DAIBER: The design pressure on the containment, again, we went back and we looked at the -- did a finite element analysis on the structural containment design itself and verified that the structure could maintain additional pressure associated with that.

MEMBER KRESS: So you reanalyzed it.

MR. DAIBER: Yes.

MEMBER KRESS: Okay.

MR. DAIBER: We did a reanalysis.

MEMBER KRESS: And you needed that for five pounds?

MR. DAIBER: Not all of the five pounds. The 59 pounds came more from the Unit 1 design consideration.

MR. ADAMS: Let me address that. My name is Doyle Adams. I was on the containment uprate project itself, also the steam generator replacement, and then was also the responsible engineer for the mods and things that was done to the containment and the repair and the testing of the containment when it

came out.

The way we came up with the amount we could actually go, which is only about five pounds, it's about ten percent additional capacity -- Unit 1 is very, very similar. It only lacks in tendons in some areas due to the design time that it was actually come in. What happened when we went through and developed a complete reanalysis of the containment using the BECHTEL BSAP program they have, which is used for San Onofre. It was designed for concrete containment.

There was additional tendons put into the containment, like we said a while ago. There was three additional tendons in each grouping for the dome and the hoop and the vertical tendons. There was three additional ones for surveillance only. They added an additional three tendons in each group to take care of construction problems that you might go into and then loss of wire with the surveillance processes over the life of the containment itself.

So you have these 18 additional tendons that were not accounted for in the original analysis, and that's where this additional capacity came in. You also have additional -- use very conservative creep values for the concrete when it was originally

done, and that allowed us to maintain more of our compression in the concrete due to less loss of creep in the concrete.

MR. DAIBER: So we have reviewed the Plant as a whole and verified that the Plant with design margin considerations can be operated at uprated conditions.

With that, I'm going to move down to the fifth agenda item, dealing with ECCS analysis. I'm going to switch things up here a little bit. And for the ECCS analysis, emergency core cooling system analysis, we analyzed the ANO2, large break LOCA and small break LOCA considerations using 10 CFR 50.46 Appendix K, approved methodologies. We used approved methodologies, a combustion engineering, all Westinghouse methodologies, to do that analysis for power uprate considerations. These are in compliance with Appendix K and hence have the conservatism associated with Appendix K built into them. They are not the best estimate methodologies that are available.

We did -- in order to accommodate power uprate, we did move to the 1999 evaluation model for the large break LOCA considerations. That was necessary to ensure that under uprated conditions we

did not have to impose any additional operating restrictions.

So we did use approved methodologies. The large break LOCA methodology is documented in CENPD-132, Supplement 4-P, Revision 1. The small break LOCA methodology, for that we used the same methodology that we were currently licensed to -- are currently licensed to, which is referred to as the S2M. It's documented in CENPD-137, Supplement 2-PA.

In performing these analyses, obviously we got acceptable results. We stayed within the acceptance criteria. The peak clad temperature for the large break LOCA analysis went up from 2,029 degrees Fahrenheit, which was analyzed with the old methodology, and it went up to 2,124 degrees with the new methodology. The small break LOCA, the peak clad temperature went up from 1,905 degrees to 2,090 degrees. We also verified that the maximum clad oxidation, the maximum core-wide oxidation and coolable geometry requirements were also maintained.

MEMBER SHACK: Did you do a full spectrum of breaks or you analyzed your limiting breaks from your previous?

MR. DAIBER: We did a spectrum of breaks. We did a spectrum of large break LOCAs and a spectrum

of small break LOCAs.

MEMBER SHACK: How did that spectrum compare with your previous analyses?

MR. DAIBER: It was effectively the same spectrum, a very similar spectrum. The break size changed on the large break LOCA, so the spectrum changed a little bit to accommodate that, to make sure we bounded it on each side.

MEMBER BONACA: For the large break LOCA, you say you used a new, approved methodology?

MR. DAIBER: That's correct.

MEMBER BONACA: Was it specifically for this change, to support this modification?

MR. DAIBER: The large break LOCA methodology was developed not for power uprate. It was developed generically.

MEMBER BONACA: Okay.

MR. DAIBER: But it was implemented, and it was necessary. The margin gained by going to the 1999 EM was necessary to ensure power uprate conditions without any additional operational restrictions.

MEMBER BONACA: Okay. So you were looking for some margin there, and this new methodology gave it to you.