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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

481ST MEETING

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THURSDAY,

APRIL 5, 2001

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ROCKVILLE, MARYLAND

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The Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. 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
GRAHAM M. LEITCH	Member
DANA A. POWERS	Member
WILLIAM J. SHACK	Member
JOHN D. SIEBER	Member

COMMITTEE MEMBERS PRESENT: (CONT.)

ROBERT E. UHRIG Member

GRAHAM B. WALLIS Member

INVITED EXPERT PRESENT:

STEPHEN L. ROSEN

ACRS STAFF PRESENT:

SAM DURAISWAMY

CAROL A. HARRIS

JOHN T. LARKINS

JAMES E. LYONS

ROBERT ELLIOTT

ALSO PRESENT:

ED ANDRUZKIEWIZ

HANS ASHAR

RAJ AULUCK

RAY BAKER

WILLIAM BATEMAN

CHARLES BRINKMAN

WILLIAM L. BROWN

WILLIAM BURTON

LARRY CAMPBELL

C. E. CARPENTER, JR.

ALSO PRESENT: (CONT.)

ROBERT CARUSO

OMESH CHOPRA

MANNY COMAR

MICHAEL CORLETTI

JAMES DAVIS

JENNIFER DAVIS

JERRY DOZIER

BARRY ELLIOT

ROB ELLIOT

J. FAIR

G. GALLETTI

BEN GITNICK

GEORGE GEORGIEV

JIM GRESHAM

CHRIS GRIMES

FRANCIS GRUBELICH

STEVE HOFFMAN

Y. GENE HSII

CHUCK HSU

B. P. JAIN

WALTON JENSEN

CAROLE JULIAN

PETER J. KANG

ANDREA KEIM

ALSO PRESENT: (CONT.)

STEPHEN KOENICK

WILLIAM KOO

P. T. KUO

CAROLYN LAURON

SAM LEE

ALAN LEVIN

CHANG-YANG LI

YUEH-LI C. LI

W. C. LIU

LAMBROS LOIS

MICHAEL McNEIL

S. K. MIFON

MATTHEW A. MITCHELL

RICH MORANTE

CLIFF MUNSON

RICHARD ORR

KRIS PARCZEWSKI

ERACH PATEL

PAT PATNAIK

CHARLES PEARCE

ISABELLE SCHOENFELD

PAUL SHEMANSKI

UNDINE SHOOP

DAVID SOLORIO

ALSO PRESENT (CONT.)

BRIAN THOMAS

EDWARD D. THROM

JIT VORA

HAROLD WALKER

DOUG WALTERS

KEITH WICHMAN

JERRY WILSON

I N D E X

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

(8:30 a.m.)

CHAIRMAN APOSTOLAKIS: The meeting will now come to order. This is the first day of the 481st meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting, the Committee will consider the following: Interim review of the license renewal application for Edwin Hatch Nuclear Power Plant Units 1 and 2; proposed final license renewal guidance documents; safety issues associated with the use of mixed oxide and high burnup fuels; thermal-hydraulic issues associated with the AP1000 passive plant design; and proposed acrs reports. A portion of this meeting will be closed to discuss Westinghouse propriety information applicable to the AP1000 design.

This meeting has been conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John Larkins is the designated federal official for the initial portion of this 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 it can be readily heard.

I will begin with some items of current interest or announcements. First, Mr. John Szabo of the Office of General Counsel will meet with us on Friday -- that is tomorrow -- at 12:15 p.m. to discuss recent changes in ethics laws and answer any questions that the members may have relating to conflict of interest, contracting restrictions, prohibited stocks, et cetera. So I suggest that we bring our lunch here and then listen to Mr. Szabo.

There will be a meeting at noon today in the Subcommittee Room with NRR staff to discuss potential synergistic effects from power upgrades, high burnup fuels, life extension, and accident precursors, and life extension, period.

Carol Harris will pass out financial disclosure forms today or tomorrow. And the members are requested to fill them out and return them to Carol at the May meeting. I will be meeting with Commissioner Merrifield today, and Dr. Larkins will be with me at 3:00 o'clock. You have received copies of

the ACRS summary matrix of 2,000 letters and outcomes that are in front of you.

MEMBER KRESS: I didn't know we had written that many

CHAIRMAN APOSTOLAKIS: Two thousand letters, yes, 2,000 letters. At least it feels that way. And it has the various criteria that we use to judge effectiveness and so on. The subcommittee chairmen are asked to find their own letters and review what's in this handout and make sure it's correct.

We will do this in tomorrow's session, the P&P session. So please read them before then. We will discuss our meeting with the Commission next month. We will discuss it today between 4:30 and 5:30 and Friday at 3:30, between 3:30 and 4:30, and Saturday as necessary.

You have this pink cover with some interesting items of interest attached, several speeches by commissioners, an inside NRC article on the DPO report, and managerial assignments and changes within the agency. So the members should find this interesting.

And, finally, I am pleased to announce that Mr. Harold Larson has been appointed as Special

Assistant and Mr. Sam Duraiswamy as Technical Assistant to the Associate Director for Technical Support of the ACRS/ACNW.

And, with all of that, we are ready to start our session. The first one is on interim review of the license renewal application for Hatch Nuclear Power Plant Units 1 and 2. Dr. Bonaca, this is your session.

VICE CHAIRMAN BONACA: Thank you, Mr. Chairman.

On March 28th, we met with the applicant and with the staff to review the application of Plant Hatch Units 1 and 2 for license renewal. We heard from the applicant, and also we had a significant amount of information before to review from the SER.

On March 27, we spent about half a day reviewing with the staff the BWRVIP topical reports for the program in general. That includes in excess of 20 topical reports, of which we have reviewed specifically 4 of them.

Those topical reports are important because they are referenced in the Hatch application. They really are the foundation to the vessel and internal inspections and evaluations that old BWR was performing. They are important to us because we will

see them likely in every application for BWRs for license renewal. Today we have the staff and the applicant coming in and summarizing for the full Committee what we heard on the 27th and 28th of March.

With that, I will move and ask Mr. Grimes to introduce speakers.

MR. GRIMES: Thank you, Dr. Bonaca.

My name is Chris Grimes. I'm the Chief of the License Renewal and Standardization Branch. I am accompanied by Bill Bateman, the Chief of the Materials and Chemical Engineering Branch.

And the staff is prepared today to summarize the material that was presented at the subcommittee meetings and to highlight those specific areas of interest that the subcommittee pointed out.

Mr. William, also known as Butch, Burton is the project manager. And Butch will present the summary of the renewal reviews. We are leading off with Gene Carpenter, who is the lead engineer on the Boiling Water Reactor Vessel Internals Project. And we have coordinated with the applicant, who is being represented here today by Ray Baker from Southern Company, in order to address the specific questions that came up during the subcommittee meeting.

And I would also like to emphasize that

this is an interim report. You know that there are a number of open items and issues under appeal, for which there is an ongoing dialogue with the applicant. And we will do our best today to represent where we stand on those issues. And we will continue to keep the subcommittee and the full Committee informed of our progress on those issues.

And, with that, I will turn it over to the staff to make the presentation.

VICE CHAIRMAN BONACA: Thank you.

(Slide.)

MR. CARPENTER: Good morning. I'm Gene Carpenter with the Materials and Chemical Engineering Branch. As Mr. Grimes said, I am the lead for the BWR Vessel Internals Project, the staff review that has been ongoing for that.

(Slide.)

MR. CARPENTER: Today I am going to give you a very brief overview of the regulatory perspective on this, what has been accomplished with the BWRVIP Program to date and how the generic aging management program has been reviewed.

Now, last week when we briefed the subcommittee on this, Mr. Robin Doyle of Southern Nuclear gave a fairly comprehensive, if somewhat

abbreviated, overview of it. And that took two hours. I have 30 minutes. So my overview is going to be exceptionally abbreviated.

To start with, BWRVIP is a voluntary industry initiative of all the BWR owners in the U.S. and several foreign reactors. It was begun in 1994 to address the core shroud cracking issue, which eventually gave rise to Draft Letter 94-03.

They now address all of the BWR internal components, the reactor vessel and an extension of what they had previously been chartered to do. They are now looking at the Class I piping material conditions also.

The guidance that the BWRs have put out covers the current operating term and also the extended operating period. The staff is looking at both of those.

BWRVIP has been proactively addressing some of the aging degradation issues that are beyond present regulatory requirements as well as those that are within regulatory requirements.

The BWRVIP has identified generic cost-effective strategies that are appropriate for plant-specific needs. They are also the regulator interface for all BWR material issues and also the

clearinghouse for all the information that has been gathered, both domestically and internationally. So they are sharing quite a bit of information, not only with themselves but also with the staff.

(Slide.)

MR. CARPENTER: One of the reasons that Mr. Doyle gave last week for all of this is that the BWRs were suffering through quite a bit of capacity loss in the early 1980s. As this chart shows, in the early '80s, the plants were down up to 20 percent of the time. And obviously when you have a nuclear reactor, you would like it to be running as much as possible.

During this time, the staff had put out quite a few information notices, bulletins, generic letters, et cetera, regarding some of the material degradation issues. And BWRs had started working on this. Again, in 1994, they started doing this as an organization, the BWRVIP organization.

(Slide.)

MR. CARPENTER: To give you a rough idea of some of the components that have been looked at here, not only are we talking about the entire vessel itself, we're talking about the core shroud, core plate, top guide, core spray piping on the internals,

the various support legs, basically everything inside that is safety-related.

(Slide.)

MR. CARPENTER: As you may remember from when the core shroud issue first occurred, some of the components that were of high concern were these welds, the circumferential welds. Later on vertical welds were also identified as a cracking problem. And that is being addressed in one of the BWRVIP reports, specifically VIP-63, which the staff has reviewed. They have also looked at, again, the support legs, the core spray piping, the top guide, more core plate, the jet pumps, et cetera.

To give you a rough idea again, all of the BWRs in the United States are members of the BWRVIP. And they all have committed to following the BWRVIP guidance as it is reviewed by the staff and approved. If they have any problem with following the guidance once it is approved, they are required to tell us within 45 days.

(Slide.)

VICE CHAIRMAN BONACA: Before you leave the figure that shows the internals, --

MR. CARPENTER: Yes, sir.

VICE CHAIRMAN BONACA: -- you might want

to point out some of the concerns there may be. I mean, for example, some failure of hold-down things in top guide may lead to core movement --

MR. CARPENTER: Yes, sir.

VICE CHAIRMAN BONACA: -- and, therefore, their ability to insert control rods. I mean, that's the kind of issues maybe the members should hear about briefly.

MR. CARPENTER: Right. Some of the issues that have arisen obviously with core shroud cracking, you lose two-thirds core coverage. If the core shroud circumferential welds do give way and there is movement of the core shroud, you could preclude the ability to perform a safe shutdown by movement, damaging of the fuel, precluding the control rods from inserting.

Another problem was with the SLC, standby liquid control system. If that failed, you would not be able to shut down under an ATWS condition.

The jet pumps, one of the things that was looked at was what would happen if you had the jet pumps disassemble. Again, that would preclude two-thirds core height coverage.

If the core spray pipes had significant cracking in it, you would not be able to perform core

spray cooling. If the top guide or the lower core plate was cracked significantly, again, more problems there. And these are all some of the issues that were looked at *in toto* as well as what would happen if you had cracking in the reactor vessel or in some of the Class I piping.

VICE CHAIRMAN BONACA: Thank you.

(Slide.)

MR. CARPENTER: Okay. The previous slide was on the domestic members. This is a listing of the present foreign member utilities. As you can see, it includes Germans, the Japanese, Taiwanese, et cetera.

(Slide.)

MR. CARPENTER: Some of the BWRVIP reports, as I said several times now, have included the BWR vessel, all safety-related internal components, and Class I piping.

VICE CHAIRMAN BONACA: Just one more question.

MR. CARPENTER: Yes, sir?

VICE CHAIRMAN BONACA: Of all the foreign member utilities you showed, are they all G.E. reactors?

MR. CARPENTER: I don't believe.

VICE CHAIRMAN BONACA: Okay. So there are

some BWR reactors of other design?

MR. CARPENTER: I believe so, yes.

VICE CHAIRMAN BONACA: Okay. So there is a sharing of information with other types of designs?

MR. CARPENTER: Right. The BWRVIP reports, again, they cover the core shroud, shroud supports, the entire list that I have here, of which the Hatch review did take a look at all of these. Some of them are not applicable to Hatch, but we will talk about that in a moment.

The guidelines were basically broken up into three main sections, those of the inspection and flaw evaluation guidelines, which create the bases for the aging management program; repair design criteria, which would be applicable at any time in plant life, either during the current operating term or the license extension term; and also mitigation guidance, which would give you a way to preclude cracking, hydrogen water chemistry, noble metal chemistry addition, et cetera. And that's also good at any time during plant life.

(Slide.)

MR. CARPENTER: To give you a brief overview, as Dr. Bonaca said at the beginning, there have been quite a few of these BWR reports. These are

the majority of the flaws, the inspection and flaw evaluation guidelines.

Several, the BWR reactor vessel pressure one, BWRVIP-74, had subsumed and the guidance that was given in BWRVIP-05, which the ACRS reviewed several years ago. BWRVIP-76, the core shroud, which started all of this, subsumes the guidance that was previously approved in BWRVIP-01, -07, and -63, -63 being the vertical welds, as opposed to the circumferential ones on the first two.

(Slide.)

MR. CARPENTER: And, as I said a moment ago, they also have repair/replacement design criteria. This is a listing of those for all of the safety-related equipment.

(Slide.)

MR. CARPENTER: And also guidance on how to evaluate crack growth and mitigation. And these all either have been reviewed or are under staff review at this time.

(Slide.)

MR. CARPENTER: Some of the other reports that have been looked at were: the BWRVIP-03 guidance, which tells the licensees how to do a consistent examination; and the -06 report, which was

a safety assessment of all the reactor internals. And that gave them the bases for determining which of these internal components would be looked at and evaluated.

The safety assessment identified components that were necessary for safe operation shutdown. The criteria that was used was to: maintain a coolable geometry, maintain rod insertion times, maintain reactivity control, assure core cooling, and assure instrument availability, all good things.

(Slide.)

MR. CARPENTER: The general format of the I&E guidelines, which, again, is the bases for the aging management program, is an overall description of the components, the inspection history, and the susceptibilities of the components; failure consequences; the inspection requirements, both scope and frequencies; flaw evaluation methodologies; and reporting requirements, what they are going to be telling the staff.

The program assures that the inspections performed correctly and on time by qualified personnel; and that the inspection results and flaws are properly evaluated and dispositioned; and that all

repairs meet approved BWRVIP criteria or applicable codes, as the case may be.

(Slide.)

MR. CARPENTER: BWRVIP conclusions were that the program is broad in scope; the BWRVIP includes appropriate inspections, evaluation methodologies, repair criteria and mitigation methods to assure BWR internals integrity; and the use of the program during license renewal period provides an adequate aging management program. Now, that --

CHAIRMAN APOSTOLAKIS: Whose conclusions are these?

MR. CARPENTER: Again, this is the BWRVIP's conclusions.

CHAIRMAN APOSTOLAKIS: Not yours? Okay.

MR. CARPENTER: I'm about to give you ours.

CHAIRMAN APOSTOLAKIS: Okay.

MR. CARPENTER: Okay?

CHAIRMAN APOSTOLAKIS: It was too good.

(Slide.)

MR. CARPENTER: Everyone has their own little advertisement that they want to put out. This is the staff's. And the staff has, again, completed the review of almost all the BWRVIP reports and those

that we have reviewed and have approved. And there have been one or two that we have not approved as either denied or not yet approved.

The staff has concluded that implementation of the guidelines as modified to address staff comments will provide an acceptable level of quality for inspections and flaw evaluations of the subject safety-related components. We have also performed and independent research review, which was NUREG/CR-6677, which I provided copies to the Committee last week. That found that comprehensive inspection programs like the BWRVIP can significantly reduce core damage frequencies.

CHAIRMAN APOSTOLAKIS: Can or does?

MR. CARPENTER: Can.

MEMBER WALLIS: Well, how does an inspection program reduce a core damage frequency? Does it lead to a reassessment of some numbers? What is the mechanism for it?

MR. CARPENTER: One second, sir.

MEMBER WALLIS: If you found something bad in your inspections, it would increase the core damage frequency.

MR. CARPENTER: What the summary for the NUREG-6677 says -- and this is on Page 194 of the

report -- "With no credit for inspections, monitoring, or repair; i.e., no BWRVIP program, and a probability of significant cracks developing one, coupled with the initiating event frequencies and system failure frequencies and the PRA studied, an undesirable increase in the plant core damage frequency; i.e., greater than $5e^{-6}$ events per year, is predicted.

"With the current BWRVIP inspection, monitoring, and repair program, there is expected to be no significant increase in CDF; i.e., less than $5e^{-6}$ events per year, caused by failures of BWR vessel internals. That is, IGSCC problems can be identified and evaluated or corrected to preclude a significant increase in core damage frequency."

So you can identify the problems before they occur.

MEMBER WALLIS: So it's the corrective action that changes the CDF --

MR. CARPENTER: That is my understanding, yes.

MEMBER WALLIS: -- or is it just your state of knowledge, which is different, because you know more?

MR. CARPENTER: If you can find a potential problem before it can become an actual

problem, then you can reduce --

MEMBER WALLIS: Presumably if you found problems which you didn't know about before, you could conceivably increase your CDF?

MR. CARPENTER: If you're correcting them before they become a problem.

MEMBER WALLIS: But if you didn't know how to correct them, you find something you didn't know was there before, it wasn't in your PRA, now it is, you could increase your CDF.

MEMBER SHACK: Well, there's the PRA.

MR. CARPENTER: That's right.

MEMBER WALLIS: But the idea is it always increases CDF. It may be --

VICE CHAIRMAN BONACA: It seems that the better way to put it would be that -- I mean, it prevents increases in CDF that would result from the cracking. I mean, that's really what it says. With respect to what we have measured today, if we did not have these inspections and the repair, we would see an increase in CDF by a certain amount they seem to quantify.

MEMBER WALLIS: What would be the mechanism for increasing that CDF? It would have to be some cracking in the map, which increases your CDF.

VICE CHAIRMAN BONACA: Sure. You have a high probability of --

MEMBER WALLIS: The crack growth is in your model, and the CDF is increasing. But by inspecting, you somehow --

VICE CHAIRMAN BONACA: For example, he would have an increase in the frequency of ATWS. Okay? And now because you have these inspections and repairs, your frequency of the ATWS --

MEMBER KRESS: It affects two things: the frequency of certain events, one of which would be ATWS. It also affects the probability of events in the event tree of going one way or another and certain event trees. It affects those probabilities. And the outcome is it in reality has effects on the CDF.

MEMBER SHACK: Yes. I mean, your computed CDF may go.

MEMBER KRESS: Sure. Your computed might have gone up, but the real CDF --

MEMBER SHACK: But your actual proved CDF, which is the one you really should worry about --

MEMBER WALLIS: There's no such things as a true CDF.

CHAIRMAN APOSTOLAKIS: There isn't such a thing. Come on.

MEMBER WALLIS: It's always a computed CDF. There's no such thing as a measured CDF. It's always computed.

CHAIRMAN APOSTOLAKIS: I think Graham is right.

MEMBER KRESS: Well, in principle, there is a CDF.

MEMBER SHACK: You may not know what it is. You may not know what it is.

MEMBER KRESS: There had better be a CDF or we are beating our head against the wall.

CHAIRMAN APOSTOLAKIS: But all you have is the computed CDF. Why is it "significantly"? I mean, why do you put the word "significantly" there?

MR. CARPENTER: I did not do this report. Is --

CHAIRMAN APOSTOLAKIS: I mean, am I to compare this with the standard 10^{-6} or less vessel --

MR. CARPENTER: Well, that they use to --

CHAIRMAN APOSTOLAKIS: -- carrier? So 5 x 10^{-6} is significant?

MR. CARPENTER: It is significant, sure.

CHAIRMAN APOSTOLAKIS: Yes. That's fine.

VICE CHAIRMAN BONACA: The question I have: In many of these reports on a related issue,

there is a statement that some of the degradation mechanism could lead to inability of inserting control rods. Okay?

And then there is a statement typically that says: However that happens, you know, the SLC system is available. And there is no discussion there on the fact that, you know, the core reliance on the SLC system is based on a very low frequency of the ATWS event. I mean, that is not something that makes me comfortable to know that if you cannot insert the rods, you have the SLC system anyway. Well, I hope we'll never have to use that system.

So I guess this is in the same contrast of the evaluation that NUREG provides, I imagine. Yes. Low probability and low likelihood. Okay.

But, anyway, I just wanted to comment how there is this dependency there on the systems that in design basis, they are not supposed to be used either for the life of the plant, --

MEMBER FORD: Gene, I have a question.

MR. CARPENTER: Yes, sir.

MEMBER FORD: -- really, following up from the meeting we had last week. And it relates to the risk management and how quantitative we are. It relates to the last line there. In the VIP documents

for disposition of the cracks for the austenitic calories, we use the upper bound of the data. What would the procedure be if in the future you found cracks going faster than that upper bound?

And, as you know, we have done that. That has occurred in the past for the ASME 11 code for corrosion fatigue. We kept on moving the line up as we got more data. Would you do the same? Would NRR advocate the same, just increasing the upper bound as you get more data? That is the first question.

The second question is both for especially the low alloy steel disposition curves. It's based on minimal data, and it is not the upper bound. How do you manage that risk or how would NRR judge the management to that risk? There could well be data above the disposition line that has been quoted for low alloy steels.

MR. CARPENTER: Dr. Ford, correct if I'm misstating what you just asked me. The first part of the question was: How would we evaluate if future data comes in that shows that the crack growth rate that we have at present is unconservative?

MEMBER FORD: Correct.

MR. CARPENTER: Okay. If we find that we have a nonconservative crack growth rate, the staff --

I feel very confident in stating this categorically -- will go back. And we will evaluate that, and we will perhaps tell them -- not perhaps. We will tell the industry to go and reevaluate based on this additional data.

MEMBER FORD: Okay.

MR. CARPENTER: Obviously we want to be conservative. We want to be safe.

VICE CHAIRMAN BONACA: But I would expect that the BWRVIP program would have procedures of this type to incorporate data in the program.

MR. CARPENTER: The BWRVIP is planned to be a living program. And they are planning to evaluate as it becomes available and relook at all of this, yes.

MEMBER FORD: And the second question, which I am really concerned about, the low alloy steel one, well, that disposition line I know because I did it was formulated almost out of the air. I hesitate to say that.

MR. CARPENTER: And I would certainly not correct you at all. You are the expert there, sir. But I will defer this to the staff expert on this.

Bill, Bill Koo, you are the one who looked at some of this low alloy steel stuff. Could you

address Dr. Ford's question, please?

MR. BATEMAN: Bill's telling me he did not perform that review. So I don't think we have that particular expertise here to support at this time. We will have to get back.

MEMBER FORD: I guess the answer would be the same as the previous one that it is a living document, if you like.

MR. CARPENTER: Certainly.

MEMBER FORD: And, therefore, you would just revise it.

MR. CARPENTER: Certainly.

VICE CHAIRMAN BONACA: Just staying on the issue, however, it would be interesting to know more about the BWRVIP program and the commitments it has. I mean, the staff cannot be ultimately responsible for all the elements of the program.

The program is really a leading program that is supported by the industry. So I would expect it would have a number of guidelines on how new information is incorporated, how it is distributed among the participants, how commitments are revised, and how the --

CHAIRMAN APOSTOLAKIS: Well, presumably, you know, the results of the inspection program are

evaluated by somebody.

VICE CHAIRMAN BONACA: Well, I mean --

CHAIRMAN APOSTOLAKIS: That's what makes it a program.

VICE CHAIRMAN BONACA: That's right, but I would like -- you know, what we have heard here is that the NRC would make certain requirements. The point is that the program really should be or has been successful before the NRC participated in that.

MR. CARPENTER: Correct. BWRVIP, as I said at the beginning, is the clearinghouse for all of this information. They do collect it. They do provide it to all of their member utilities. And they do evaluate all of the material that is looked at. And they do come in and meet with the staff on a regular basis to discuss the materials issues that they have been evaluating, both domestically and the information that they receive from overseas.

To date, whenever there is a problem or there has been a concern raised, they have been very fast in responding to that problem. For instance, a couple of years ago, we had an instance with cracking in the jet pump elbow risers. The BWRVIP took that on very fast, and they did resolve it with the issuance of a couple of reports, including the BWRVIP-28

report, which gave us a justification as to why the operating plants were safe to continue operation until they could perform inspections, and then later on with the BWRVIP-41 report, which it gave inspection guidance.

So they are looking at issues as they do arise. And obviously the staff is looking at the same issues on a concurrent basis.

Yes, sir?

MEMBER SIEBER: If I would go back to Slide 3, --

MR. CARPENTER: Yes, sir.

MEMBER SIEBER: -- which shows the core shroud, you talk about these inspections, but the geometries for the welds shown in that figure to me would be pretty complex. And so my question is: What kind of inspection do you do? And how certain are you that you detect whatever indications are there in the geometry that is shown on this figure?

MR. CARPENTER: The BWRVIP has guidance. Originally the BWRVIP was seven guidance for the inspection of the core shroud circumferential welds. That was later added to with the -63 report, which deals with the vertical welds. And then it was all subsumed into the BWRVIP report, which is still under

staff review.

They also have the BWRVIP-03 report, which is the guidelines on how to perform inspections, visual, UT, ultrasonic examinations, various other types of examinations that would be done of the vessel. It gives you guidance on how to qualify the inspections and what makes a successful inspection.

So when they perform these inspections to the guidance of the staff-approved BWRVIP-07 and -63 reports, using the -03 guidance, which has also been reviewed and approved by the staff and modified with staff comments, then we have a fairly high confidence level that you are going to find whatever there is to be found.

Does that answer your question, sir?

MEMBER SIEBER: Yes. Just as a little bit of a follow-up, though, if I look at a VT-type inspection, the indication has to be pretty substantial in order to pick that up as a VT.

MR. CARPENTER: Well, bear in mind the VT-3 examination, which is code-required, is a very broad examination.

MEMBER SIEBER: Right.

MR. CARPENTER: The BWRVIP has taken that. And they have reduced that down to an enhanced VT-1,

which is a one-half mil examination. So it is a much, much finer examination.

MEMBER SIEBER: So you have gone beyond the code requirement?

MR. CARPENTER: The BWRVIP has gone considerably beyond code requirements, yes.

MEMBER SIEBER: Thank you very much.

MEMBER POWERS: I don't really understand the response. It says: Gee, BWRVIP used a bunch of expert opinion to come up with an inspection technique. The staff looked at that. And based on their expert opinion, they approved it.

Does anybody at any time go back and say, "Okay. Here is a system that we know has flaws in it. Show that the technique, in fact, does find those flaws"?

MR. CARPENTER: Yes, sir. The EPRI/NDE Center qualifies the inspectors.

MEMBER POWERS: It qualifies them for the techniques against some sort of sample. But he is asking: In this geometry, in this complexity, does it work?

MEMBER SIEBER: That's different.

MEMBER POWERS: That's different.

MR. BATEMAN: Bill Bateman on the staff.

I think we would need to adequately address your question for you to select a particular weld which you thought was a complex geometry. And once we understood what particular weld we were talking about, we would be better able to give you an answer. We might even have to go back to the BWRVIP to help get that answer.

MEMBER POWERS: I think that would be a useful thing for me to formulate the question that way. I don't think I can. But I think there is a generic issue here, one that we need to think about a little bit. What can we do to validate by actual experience, rather than expert opinion, these judgments on the adequacy of the inspections?

Now, in some cases; for instance, in the flaw distributions and pressure vessels, we have been fortunate enough to get a couple of pressure vessels? And they tear them apart at Oak Ridge or something like that. And they get an actual distribution, and they can do a lot of things.

Is there anything in the offing of getting some actual internals someday that we can keep Oak Ridge busy tearing things apart looking for flaw distributions?

MEMBER SHACK: They'll still be screaming

hot.

MEMBER POWERS: Well, these vessels aren't a walk through the park either.

MEMBER SHACK: Compared to the core, they are.

MEMBER WALLIS: It's very simple, then. You just deny license renewal. Then you've got a vessel you can take apart.

VICE CHAIRMAN BONACA: Actually, we could ask a question of the licensee that they had indications on the shroud they could not tell if, really, there were actual cracks. But they repair them anyway because of the concern they had.

Could you expand on how effective it was in the inspection, what the difficulty was in determining whether it was an incipient crack or --

MR. BAKER: I'm looking to Charles Pearce in the audience. And I am not sure that either one of us have the actual detailed knowledge of the repair that was affected today. We can certainly follow up at a later date.

VICE CHAIRMAN BONACA: For the application, it sounds like, really, you can tell if it was a crack or not.

MR. BAKER: It was my understanding that

we preemptively repaired it. So whether there was a crack or not did not matter.

VICE CHAIRMAN BONACA: That's right.

MR. BAKER: The repair was to support it in a different way.

VICE CHAIRMAN BONACA: Wouldn't that pump be a comment on the difficulty of making that determination?

MR. BAKER: Yes. I just don't know.

VICE CHAIRMAN BONACA: Yes. Thank you.

MEMBER SHACK: I think Dana's comments are correct. I can't think of any situation in which one has qualitatively determined the probability of protection for an NDE technique except maybe steam generator tubes. It's largely the difficulty of getting representative samples.

You know, most people aren't going to volunteer to take their reactor apart. Even if you could afford to do it, the sampling sizes you get are just small. I mean, I think it is important in this particular case, as Gene mentioned, that the VIP has committed to the enhanced VT-1 with the half mil resolution.

In this particular situation, the flaw tolerance is such that, by and large, these cracks

have to be very large before they are structurally significant. And so probably it is an expert judgment again, but I would probably be more confident that I could detect a crack of structural significance here with the enhanced VT-1 than I probably would -- you know, that I would be more confident in that than I would be most inspections, you know, my probability of detection of the structurally significant flaw.

But, again, it certainly hasn't been demonstrated in any rigorous fashion.

VICE CHAIRMAN BONACA: We just recently had the experience where inspections were conducted, nuclear inspections, and nothing was done. And then --

MEMBER SHACK: Borton follow-up is a very effective inspection.

VICE CHAIRMAN BONACA: Well, when you find a Borton, you find that you have a crack. Then you look back at the other nozzles, and you find that you have indications that you hadn't seen the year before.

MEMBER POWERS: It doesn't work at all for BWR.

VICE CHAIRMAN BONACA: No. Borton inspections aren't very good for BWR.

VICE CHAIRMAN BONACA: No. I understand.

I am only saying that I think the issue of inspections is a very important one. I think the answer maybe is the one that Bill is offering, that before you have a real effect, you would have a visible indication.

MEMBER SHACK: Well, I think it was important to go to the enhanced VT-1 because, as Jack mentioned, VT-3 sees when they are broken parts laying in the reactor. And even VT-1 is like a 132nd resolution, --

VICE CHAIRMAN BONACA: Right.

MEMBER SHACK: -- which is like for a stress corrosion crack, rather difficult. But, again, when you get to the enhanced VT-1 and you have a fairy large flaw tolerance, then you begin to I think develop more confidence.

MEMBER SIEBER: I take it a lot of surface has to go on prior to the actual examination.

MR. CARPENTER: That is correct, yes. The BWRVIP-03 document does describe in detail how you are supposed to clean the lighting, et cetera.

MEMBER SIEBER: Right.

MR. CARPENTER: Bear in mind visual examinations are not the only examinations being performed. They all started performing ultrasonic examinations.

MEMBER SIEBER: Yes. That bothers me, too, a little bit. When I look at welds like H3 and H5, the only UT shots you can make are angle shots. And you may not be able to differentiate in the area of the lower core plate what components are where from a UT readout. It just seems complex to me.

MR. CARPENTER: I understand.

MEMBER WALLIS: When you look on the bottom of one of these vessels, what do you see? Do you see junk of any sort or is it bright and clean and shiny or what?

MR. CARPENTER: I don't know the answer to that, sir. I haven't looked in the bottom.

MEMBER WALLIS: I just want a feel for what kind of things you see in there when you look.

MEMBER SIEBER: I think you see a lot of crud.

MEMBER WALLIS: There's a lot of dirt or buildup?

MEMBER SIEBER: Well, it's crud, which is --

MEMBER WALLIS: Unidentified deposit?

MEMBER SIEBER: Well, it's usually sort of a harder deposit in the core area because softer ones would be swept away. You know, there is boiling and

all kinds of turbulent flow in there. So it would be an adhered hard type of crud.

MEMBER WALLIS: An unidentified crud.

MEMBER SIEBER: Which has to be cleaned off to do a VT-2 point.

MEMBER LEITCH: Sometimes you see some pieces of debris, too. Like down at the bottom, we have had problems with -- there is a suction line right from the bottom to -- I think it goes to reactor water cleanup that has been plugged or obstructed at several plants as a result of maintenance losing pieces of things down in that suction line.

MEMBER FORD: Gene, could you comment on the question of inspection frequency? You talk about it being a proactive plan, which it is. As you go into a new era, like a relicensing era, you don't really know what you are starting with because not everything has been inspected, especially down in the bottom of the reactor. And all of the stub tubes going through there, not all of them have been inspected.

Is that something that would normally be required by the NRR or how would you deal with that?

MR. CARPENTER: Dr. Ford, you play a great straight man. Specifically for the lower plenum

internals, the staff has requested that the BWRVIP revise their document to go in and do a baseline inspection of the internals so that you do know what you have in there during the current operating term. And that way when you go into the license renewal, you will have a benchmark. So you will be able to see that.

MEMBER FORD: The reason why I understand that there has been a cracking incident at Nine Mile Point, I'm told that that was not inspected. And, yet, you had a very large crack all the way around this particular weld. And it hadn't been inspected at all.

So how can we guarantee or ensure that there is a minimal possibility of cleaning that in the future? Would this program of inspecting the reactor, 100 percent inspection of the reactor, before relicensing solve that particular problem; i.e., starting your clean slate, you know what your devil is?

MR. BATEMAN: This is Bill Bateman from the staff. I don't think that we can tell you with any 100 percent certainty if the BWRVIP does generate an inspection, that they will be able to identify 100 percent of the potential defects at the bottom of the

core stub tube welds at our CRDM housings, et cetera. I don't think we're going to tell you that.

I think what we can say is in the case of the Nine Mile one, they did identify the leak. They did come in for a relief request to do a roll repair. And we accepted that under the proviso that they would subsequently develop a permanent repair.

So that is typically how we would handle items that were missed in an inspection. You know, they would manifest themselves in some kind of a leak later on.

MEMBER LEITCH: The Hatch license renewal application depends upon certain BWRVIP reports that have yet to receive staff approval. What is the logic of the resolution of that? Do we expect that those reports will be approved prior to the Hatch application being approved or is Hatch committed to live by those VIPs once they are approved? How did that work out?

MR. CARPENTER: Well, let me address first the BWRVIP reports that the staff is reviewing. And then I'll pass on what Hatch specifically is going to be doing.

There are two inspection and flaw evaluation guidelines that the staff has not yet

approved which Hatch is referencing. And those are specifically BWRVIP-74, which is the reactor pressure vessel guidelines, and BWRVIP-76, which is the core shroud guidelines.

Now, please note -74 is a revision to the BWRVIP-05 document, which the staff has approved previously and we did talk to the ACRS about. That again is available of the licensees to perform inspections to that guidance.

The VIP-76, the core shroud, subsumes three other documents, which the staff has already looked at, VIP-01, -07, and -63. -63 still has open items on it, and the BWRVIP still owes a response to us to that, which is the reason the -76 document is still under staff review.

Once we look at all of those, it is going to be a fairly -- I won't say minor effort, but it will be a fairly quick one to complete the reviews of those two documents.

So yes, I do expect that by the time the final SE for Hatch is issued, we will have completed the reviews of these two documents.

VICE CHAIRMAN BONACA: From what you have said, what you are telling me is that you don't see the issues being reviewed are major issues of

contention or problems?

MR. CARPENTER: There are some open items still in the Hatch review.

VICE CHAIRMAN BONACA: Yes.

MR. CARPENTER: But those I'm not ready to address at this time.

VICE CHAIRMAN BONACA: I'm not talking about the elements of those vessel and shroud VIPs that have not been approved yet.

MR. CARPENTER: Hatch has --

VICE CHAIRMAN BONACA: Not Hatch. I'm talking about the VIPs.

MR. CARPENTER: Oh, okay. If you're talking about just those two reports, --

VICE CHAIRMAN BONACA: Yes.

MR. CARPENTER: -- no, I don't see that we are going to have a terrible amount of contention between the staff and the VIP to resolve the open items.

VICE CHAIRMAN BONACA: That's the sense we got during the subcommittee meeting.

MR. CARPENTER: Yes, yes.

VICE CHAIRMAN BONACA: Thank you.

MR. CARPENTER: And if there are no other questions on this, I will go to my final slide.

(Slide.)

MR. CARPENTER: The staff is completing the review of the license renewal appendices. And we have found that by referencing the aging management programs and completing the action items in the staff's SE, that there will be a reasonable assurance that applicants will adequately manage aging effects during the extended operating period and that the generic AMPs usage will significantly reduce staff review of license renewal applications in the future.

MEMBER WALLIS: This reasonable assurance is somebody's judgment?

MR. CARPENTER: Yes, sir.

MEMBER WALLIS: This is a nice sort of expression here, but what do you really mean by "reasonable assurance"?

MR. GRIMES: This is Chris Grimes. I'll address that question because this transcends license renewal.

Reasonable assurance is the finding that we have associated with our libation under the Atomic Energy Act because we cannot provide the public with certainty of safety. We developed a finding that was derived from the requirements in Part 50 that say that our obligation is to have reasonable certainty,

reasonable assurance, that the plant is safe. And the whole construct of the regulations is built around that.

Each individual piece, whether it's the vessel internals program or the adequacy of aging management associated with water chemistry or the completeness of the scoping, all of those are predicated on individual staff judgments that are founded in criteria that we usually promulgate in reg guides and the standard review plan.

MEMBER WALLIS: So these are the same words you use when you have a new reactor. So one could conclude that the licensed reactor is as safe as a new one.

MR. GRIMES: I wouldn't go that far. I would say that there are standards that were established on a different basis. We use --

MEMBER WALLIS: It's less safe than a new one. So how much less safe is it?

MR. GRIMES: We don't make any assertion that it's more or less safe. We assert there is reasonable assurance that aging will be adequately managed for the purpose of issuing a renewed license. But the original license we established reasonable assurance that this plant will operate within its

design envelope.

MEMBER WALLIS: I'm just saying if I try to explain that to an undergraduate, it doesn't mean anything. It just means that the staff is satisfied. I like that. That's fine. You're doing your job.

But it's not English. It's not something that is the understandable to the public. If you could say these are as safe as they were when they were new or something, some sort of measure of this assurance, it might be more helpful.

MR. GRIMES: It's a very good point. And so I don't want to make light of it. The difficulty that we have is trying to establish in plain language what constitutes -- we're satisfied it's safe enough, recognizing that the degree, whether it's more safe or less safe, is something that evolves. And that is why license renewal focuses not on some established line in a sand of safety but more the processes that are used to continually challenge the judgment over time.

And we will continue to try and work on articulating some simple explanation for the purpose of trying to explain to the public how we reach these decisions.

MEMBER WALLIS: One problem is, of course, it's not risk-informed. As you continue to measure

the risk, you might be able to provide assurance that it's no riskier than it was.

MR. GRIMES: I would like to be able to say that. I hesitate primarily because of the process aspect and the state of the knowledge. Several comments before got to the complexity of the inspection activity relative to a finding of whether or not we have identified everything that possibly could happen. And we don't emphasize enough the living program aspect that learns as it goes. And reliance on the quality assurance process is to change behavior when knowledge teaches you something different.

I think that we might say that we believe that it will be as safe or more safe, but then when we're challenged by a quantitative measure that we struggled to be able to explain what we thought was safety when it was originally licensed versus what we know of safety today versus what we speculate about safety in the future.

MR. CARPENTER: If there are no further questions on the BWRVIP, I will turn this over to Mr. Baker.

VICE CHAIRMAN BONACA: Thank you. I appreciate it. Any other questions for Mr. Carpenter?

(No response.)

VICE CHAIRMAN BONACA: If none, then we can move on. I believe we have now a presentation by Southern Company. Mr. Baker?

(Slide.)

MR. BAKER: Good morning. My name is Ray Baker, and I am the Hatch project manager for the Hatch license renewal application. I would also like to say that with me today is Charles Pearce, who is my direct supervisor, who is the manager for the license renewal group at Southern Nuclear. I appreciate the opportunity to speak to you today on behalf of Plant Hatch.

In the subcommittee meeting last week, we were asked to specifically focus on two items for your attention today. So today I am pleased to speak in some detail about the recent Hatch operating experience and to discuss our programs in terms of existing, enhanced, and new programs.

(Slide.)

MR. BAKER: I would like to first provide a summary discussion of the Plant Hatch vessel internals operating experience. And following that I will discuss the significant aging issues that Plant Hatch is currently addressing; that is, those items

that were observed during the five years preceding the Hatch application's submittal.

This discussion addresses aging issues only for those systems, components, and structures that are subject to aging management review under the license renewal rule.

First I would like to discuss our reactor vessel internal experiences. And we have actually talked some about that already, but let me go back a bit further than the shroud to the core spray spargers.

On Unit 1, IGSCC was identified in one of the core spray spargers early in life. That was repaired by a mechanical clamp. No additional IGSCC or other degradation has been detected since then. A full flow injection test was formed a few refueling outages ago with pre and post-injection inspections. And no problems were noted.

Another experience relates to feedwater nozzles. Unit 1 experience feedwater nozzle cracking in the late 1970s we replaced and the old slip-fit sparger that was the original design with the triple-sleeve, double-piston sparger. And we modified operation of the feedwater flow controller at that time. These changes appear to have eliminated the

causes of cracking in that component.

The Unit 2 sparger was replaced during construction with a welded sparger. And these fixes that Plant Hatch and other BWRs have implemented appear to have resulted in elimination of feedwater nozzle cracking. This was identified in a Hatch submittal that led to a generic submittal for the current inspection program. That is a revision to the original NUREG-0619 program that the BWRs use for feedwater nozzles. This, in turn, is referenced in BWRVIP-74 as a corrective approach for extended operation. And this is also referenced in the GALL.

As we noted earlier, both core shrouds have been preemptively repaired. The repair hardware and the vertical welds are inspected per the BWRVIP criteria.

And the final internals item I would note is that the access hole covers have been replaced with covers attached by mechanical means, as opposed to welded. And the materials used in the replacement covers are not considered to be IGSCC-susceptible.

MEMBER LEITCH: You have removed the CRD return line from both Hatch units, the CRD return line with a nozzle on the vessel that was experiencing some cracking?

MR. BAKER: I'm not familiar with that. I'm sorry. I don't know.

MEMBER LEITCH: I think most of the BWRs had removed that, but my question was basically specifically related to Hatch. So I would like to know the answer to that question when we get a chance.

MR. BAKER: We'll follow up with that.

MEMBER LEITCH: Thank you.

MR. BAKER: Next I'll turn to the current aging issues for the in-scope system structures and components; that is, those components that are of particular interest for license renewal. First I'll mention the control rod drive cap screws. Across the BWR fleet, a number of control rod drive cap screws have exhibited indications of localized corrosion and stress corrosion cracking.

G.E. issued a SIL, SIL Number 483, to address this issue. G.E. determined that inadequate design in conjunction with environmental conditions contributed to the failures. G.E. developed redesign cap screws to mitigate that degradation. The new cap screw design has a larger radius at the shank-to-head transition region to reduce stress concentrations and to fabricate from a higher-strength material. It includes a new washer design that features slots to

facilitate drainage of any collected fluid.

These indications that were observed were detected during VT-1 examinations. And no bulking failures occurred. Plant Hatch is currently in the process of upgrading all the control rod drive cap screws to the new G.E. design.

Next I'll discuss plant service water piping corrosion and fouling. Instance of fouling and corrosion in plant service water pipelines have occurred and continue to occur at Plant Hatch.

Areas of significant degradation or leakage have been limited to smaller diameter piping sections less than or equal to four nps. Specific areas of focus are low flow areas where fouling and localized corrosion may occur in creviced areas and in heat exchangers. In many cases, the plant service water and RHR service water piping inspection program identified the degradation prior to leakage. In all cases, no loss of system-intended function occurred.

The plant service water and RHR service water piping inspection program does aggressively seek out those areas where degradation may be occurring based on past experience. So it is experience-rated. The future inspections are based on the past experience.

We continue to selectively replace sections of carbon steel piping in this river water environment with 304, 304L, or AL-6XN stainless steels to greatly reduce the potential for recurrence.

The next area of operating experience I would like to speak to is flow-assisted or flow-accelerated corrosion; in particular, in the high-pressure coolant injection system and the reactor core cooling system.

We had initially excluded locations in HPCI and RCIC from the fact program based on their low usage. These systems are expected to operate less than two percent of the time. However, degradation and minor leakage of piping downstream of the HPCI and RCIC steam supply drain pipes has occurred in the past five years. This is piping that is downstream of the condensers for these turbines.

The identified leaks were minor in nature. And no loss of intended function occurred. These indications resulted in the addition of fact program sample points in these two systems for the Plant Hatch application.

The next area I would like to speak to is related to the torus shell, the corrosion of the torus shell. Plant Hatch protective coating activities in

the torus have identified limited areas on the interior torus shell surfaces where some breakdown of the inorganic zinc coatings and subsequent localized corrosion have occurred.

The protective coatings program provides for regular monitoring of the corrosion rates in the torus and for repair of degraded coatings and surfaces. And no loss of intended function has ever occurred with regard to this.

Another area of interest is general corrosion of carbon steel in components such as piping and supports in areas routinely exposed to weather, such as intake structure pit area, service water value pits, and the emergency diesel generator-building roof. Plant Hatch has implemented actions to address those areas and is in the process of implementing additional actions to identify and prevent future degradation occurrences due to weather exposure.

Finally, I would like to mention the fire water storage tank. Damage to the original installed vinyl coatings and subsequent corrosion of fire water tanks has occurred due to various causes. The Plant Hatch fire protection program identifies this degradation during routine inspection of the tanks and provides for continued monitoring of those areas of

degradation. No loss of intended function or leakage of any kind has occurred due to this degradation.

MEMBER SIEBER: What kind of water treatment do you use for fire water?

MR. BAKER: This is deep well water. So there is no water treatment applied to that.

MEMBER SIEBER: Treatment.

MR. BAKER: That's right. It's raw water.

MEMBER SIEBER: So it's pretty high in dissolved solids and minerals and --

MR. BAKER: It's raw water.

MEMBER SIEBER: Thank you. Filter?

MR. BAKER: That's deep well. So it's a clean source, yes.

MEMBER WALLIS: But deep wells have lots of dissolved materials in them. Water from deep wells has all kinds of stuff in it.

MR. BAKER: Yes, sir. There are chemistry samples taken. And there are limits applied to that that --

MEMBER SIEBER: But there is basically no treatment?

MR. BAKER: There's no treatment. That's right.

VICE CHAIRMAN BONACA: You mentioned in

the beginning that you replaced the vessel access hole cover plates?

MR. BAKER: Yes, that's correct.

VICE CHAIRMAN BONACA: Okay.

MR. BAKER: They were replaced with a mechanical design, as opposed to a welded-in design.

VICE CHAIRMAN BONACA: So they have been experiencing degradation?

MR. BAKER: We replaced them. And I do not recall if that was a preemptive repair or whether there was an indication it was observed.

MEMBER LEITCH: There were at least industry indications.

MR. BAKER: Yes, there were industry indications. I don't recall whether there was one at Hatch or not.

MEMBER POWERS: Can I come back to this fire water tank that you have?

MR. BAKER: Yes.

MEMBER POWERS: You say that you have a degradation because the liner has been damaged in the past. And it is corroding. But no loss of function has occurred. How long do we have to wait before it does have a loss of function?

MR. BAKER: The entire purpose of the

monitoring program is to prevent that from occurring. So that is is --

MEMBER POWERS: I guess I am a little perplexed. Corrosion is only taking place when the guy is inspecting it?

MR. BAKER: No, that's not --

MEMBER POWERS: Well, what is it about the inspection program that prevents the tank from failing at 1:00 o'clock in the morning?

MR. BAKER: First, the corrosion is not significant corrosion. It is a surface corrosion that is well-behaved. It's not something that is a rapidly occurring situation.

The monitoring is frequent enough to observe any progress of it. It is in localized areas where the damage to the liner had occurred. And there are acceptance criteria relative to how much corrosion would be allowed before further action would be required.

Routine maintenance activities are performed in the plant. So this is not something that would just be left to corrode through to failure.

MEMBER SIEBER: But I think there is another issue, which you may be referring to, Dr. Powers. If the liner comes off, it's inorganic, and

it usually comes off. It's flakes. Flakes go through the fire water system. And if you have all of the sprinklers in the plant, the sprinkler heads have pretty small nozzles in them. And so they're susceptible to plugging from this debris caused by the coating.

If I remember your application, you actually have two ranks.

MR. BAKER: Two tanks. Yes, that's right.

MEMBER SIEBER: And they are 300,000 a piece?

MR. BAKER: Yes. Large tanks, yes.

MEMBER SIEBER: So one of the tanks by itself is adequate to satisfy the code requirement for a fire water system. Does that mean that you on occasion drain the other tank through the inspection system?

MR. BAKER: That's correct.

MEMBER SIEBER: So the tank is fully drained. And, therefore, you can work on the coding and restore it as necessary?

MR. BAKER: That's one of the mechanisms where some of the damage has occurred, in fact, is from scaffolding up inside a tank to nick the coatings.

I would also observe that outside the scope of license renewal, just as part of routine plant activities, there is a plan to drain and recoat those tanks with a newer state-of-the-art.

This coating was the state-of-the-art 25 years ago or so. When it was applied today, it's no longer state-of-the-art. I believe that there will be a recoating of that in the future.

But it is from our perspective here in managing the aging, the focus would be to make sure that we have it captured by identifying it and then managing it.

MEMBER SIEBER: A secondary issue is the fact that you have debris now in fire water.

MR. BAKER: Yes.

MEMBER SIEBER: And if it goes to sprinklers, you may have sprinklers that don't operate.

MR. BAKER: That's right. Thank you.

MEMBER LEITCH: What's the material of the recirc piping at Hatch? Is it still 304 stainless? Most of the plants of the Hatch vintage had 304 and were --

MR. BAKER: Unit 1. Unit 1 has the original recirculation piping. So it's the original

304 or 304L. I do not recall which. Unit 2, the recirculation system piping was replaced. If my memory serves me correctly, it's 316 nuclear grade of the place design so that it doesn't have the dead ends on it.

MEMBER LEITCH: Yes. Thank you.

MR. PEARCE: Ray, my name is Charles Pearce. I'm with Southern Nuclear. I stepped out for a second. I can give you your answer on your CRD return lines. They were cut and capped. We do an inspection of that weld periodically. The lines now feed into the reactor water cleanup. So, actually, the CRD line was rerouted to reactor water cleanup, which now feeds back into the feedwater, ultimately back into the vessel.

MEMBER LEITCH: That's both units?

MR. PEARCE: Both units.

MEMBER LEITCH: Yes, thank you.

MR. BAKER: Thanks. I just could not recall whether we had done that specifically.

MEMBER LEITCH: Thank you.

(Slide.)

MR. BAKER: Now I would like to turn to the Plant Hatch license renewal programs. This first viewgraph lists the existing programs that we had

credited. We characterize a program as existing, as opposed to enhanced or new, if only administrative or minor technical changes were made.

Typical administrative changes include revisions to identify the license renewal commitments in the program. For example, you see several water chemistry programs in the left-hand column. And so for each one of those, the applicable water chemistry programs would note commitments to the minimum standards that are contained in the appropriate EPRI BWRVIP water chemistry guidelines. In addition, technical changes of a minor nature were made to the two programs that I have highlighted there in the blue.

MEMBER SIEBER: Do you use hydrogen injection?

MR. BAKER: Yes, we do. It is a part of the regime that is provided for in the EPRI water chemistry guidelines.

MEMBER SIEBER: Right.

MR. BAKER: There are two modes you can do it with or without. Certainly there is no desire to do it any period of time without. Our normal mode is with hydrogen injection.

MEMBER SIEBER: Have you used hydrogen

injection? For how many years? The plant is too old.

MR. BAKER: We were one of the first.

MEMBER SIEBER: The plant is too old to have always used it.

MR. BAKER: No. We were one of the first.

MEMBER SIEBER: All right.

MR. BAKER: So that I don't recall the exact year. For a number of years now.

MEMBER SIEBER: Okay.

MR. BAKER: And we also have aggressively pursued and implemented a noble metal addition.

MEMBER SIEBER: All right. Okay.

(Slide.)

MR. BAKER: On this next viewgraph, I list our enhanced programs. As you can see on this viewgraph, most of the programs were enhanced by broadening the scope of the program. I would note that the categorization here is not absolute. All of these programs, perhaps with the exception of structural monitoring program, also include monitor technical additions.

However, for the programs, protective coatings program and equipment piping and insulation and monitoring program, the technical changes that we made for license renewal were more extensive.

MEMBER SIEBER: In the structural area, do you monitor building settlement?

MR. BAKER: Building settlement has been observed user technical specification requirements from the beginning of operation. And a consolidation settlement occurred prior to the completion of construction. And we have observed no significant differential structure to soil or building differential settlements.

So it's not really a part of the structural monitoring program.

MEMBER SIEBER: Do you have a requirement to survey the buildings with appropriate benchmarks that see over the years how much one changes relative to the other?

MR. BAKER: We continue to monitor building settlement by the tech specs.

MEMBER SIEBER: All right. Thank you.

MR. BAKER: Yes, sir.

(Slide.)

MR. BAKER: Finally, this viewgraph depicts the new programs that are being accredited for license renewal. The four programs on the left are the four new one-time inspections. These inspections are to be performed during the last five years of the

current term and serve as confirmatory inspections. Therefore, areas where we believe no significant age degradation is occurring beyond that which is being managed by other programs, these inspections will be used to confirm those expectations.

The three highlight programs contain many elements that were contained in existing plant procedures and activities. However, a number of those activities were not appropriate for crediting and license renewal. So we have repackaged, revised, and rearranged those activities into the three programs shown here for primarily documentation purposes.

So these are the 30 programs and activities that will function during the renewal term to adequately manage aging effects for the end scope system structures and components at Plant Hatch.

That concludes my presentation. Are there any questions?

MEMBER FORD: What spurred the galvanic susceptibility inspection? Was it a problem that you foresaw or was there a real problem that you reacted to?

MR. BAKER: It's potential. We have a number of dissimilar connections; for example, in-plant service water. And we want to observe it.

That will be the leading indicator for us. We believe it's raw water and dissimilar metal connections. So we would want to make sure.

MEMBER FORD: Okay. So it is not in the raptor itself?

MR. BAKER: No. No, sir.

MEMBER SIEBER: Another aspect of galvanic corrosion is the grounding mat. What steps do you take to determine that it is still intact and capable of performing its function?

MR. BAKER: The grounding was not an end scope component for license renewal in our plant, but I would need to find out what the routine maintenance of those is.

MEMBER SIEBER: When those mats fail, when a plant gets 40 or 50 years old and those mats deteriorate, then you can take a Simpson volt meter --

MR. BAKER: Yes.

MEMBER SIEBER: -- and go from one pillar to another and get 10 or 15 volts. Sometimes that changes trip settings on equipment, causes higher currents during restarts. It can make a lot of problems.

MR. BAKER: I know that we have paid attention to the grounding mat for the 2 units over

the first 20 years, but I would have to specifically address that later as to what we currently are doing.

MEMBER SIEBER: Thank you.

VICE CHAIRMAN BONACA: Just for clarification, a passive component inspection, that's why you have an inaccessible component inspections; right?

MR. BAKER: Yes, that is correct. Yes, primarily the focus of that is when something is excavated or exposed that is normally not accessible, we will take advantage of that opportunity to examine it.

VICE CHAIRMAN BONACA: Yes.

MEMBER LEITCH: I'm concerned about the suction to the river water pumps. I'm not sure what you call them, but I assume you have river water cooling a heat exchanger which, in turn, cools the RHR system.

MR. BAKER: Yes. It's a part of RHR system. It's RHR service water.

MEMBER LEITCH: RHR service water. And they take suction. Those pumps take suction from the river?

MR. BAKER: Yes, that's correct.

MEMBER LEITCH: Now, I'm not familiar with

the configuration of Hatch. I was kind of concerned about this over years silting building up and then some unusual tide condition occurring, high winds or something, that might cause those pumps to lose suction.

MR. BAKER: We have a couple of activities that address that. The Altamaha River is basically a floodplain. It's a meandering river historically. The area immediately adjacent to the plant has been straight for a number of years. It is a nice straight section of the river.

We have permits for dredging. And we do dredge in front of the intake structure approximately every 18 months. There is also a periodic inspection by divers that we send down to make sure that the actual intake structure pit itself as clean. So those activities occur routinely.

MEMBER LEITCH: Okay. Thank you.

MR. BAKER: Thank you.

VICE CHAIRMAN BONACA: Any other questions for Mr. Baker?

(No response.)

VICE CHAIRMAN BONACA: If not, thank you for your presentation. And now we want to hear from the staff, somebody with the NRR. Mr. Burton?

(Slide.)

MR. BURTON: Good morning. My name is William Burton. I generally go by Butch. I am the lead project manager for the staff review of the Hatch license renewal application.

I want to make my apologies up front. I like to make my mistakes early, obviously full Committee, as opposed to the subcommittee meeting.

(Slide.)

MR. BURTON: The first thing I want to do is give a little overview of the Hatch application submittal. The application was submitted by letter dated February 29th of last year. As you all know, it is a two-unit boiling water reactor. It is located about 11 miles north of Baxley, Georgia and approximately 70 miles from Savannah, Georgia, west of Savannah.

Right now Unit 1, its current license is due to expire in August of 2014 and asking for a 20-year extension to 2034. Similar, Unit 2, current license is due to expire in June of 2018, again a 20-year extension to 2038.

I did want to put up briefly -- this is not in your package -- just where we are in terms of the review.

(Slide.)

MR. BURTON: We just completed on March 16th the AMR inspection. We took a team of folks from both Region 2 and from headquarters to go down and see how some of the commitments that are currently outlined in the aging management programs are actually being implemented on site.

And compared to some of the previous applications, Southern Nuclear is a lot further along at this point in terms of actually implementing those commitments from the aging management programs into their on-site procedures.

MEMBER WALLIS: I would think this is very important. I mean, I read the SCR draft. It seems to be this assurance that they have these programs. I don't have the same assurance that they are really good programs, that they are good enough programs. Just the fact that they have a program doesn't mean to say that it is good enough.

MR. GRIMES: This is Chris Grimes. I would like to emphasize that the scope of these inspections is intended to verify that the procedures are in place or that the attributes of the program relative to scope, methods, criteria, and so forth are there.

Another aspect of the inspection includes the inspectors looking at the effectiveness of the programs relative to operating experience. Now, clearly if they are new programs, you are correct. There's not much we can ask the inspector to do about trying to assess the effectiveness of the program.

For some of the longstanding original inspection and maintenance activities, we do gather insights in terms of the effectiveness of the programs in order to try and bolster the conclusions in the safety evaluation about the effectiveness of the programs. So it is an aspect of the reasonable assurance finding we try to develop.

VICE CHAIRMAN BONACA: And I understand also that, although it is not referenced yet because it is not finally approved, the GALL information has been extensively used as a reference for evaluation.

MR. GRIMES: Yes, sir, that's correct. The staff had the benefit not only of contributing to GALL in parallel with this review but also having it available for the users to use as a reference material, even though we don't explicitly cite it in the safety evaluation.

VICE CHAIRMAN BONACA: Thank you.

MEMBER POWERS: Before we move on, could

I ask a question about this inspection team that you send down there? Did that include people who looked at the fire protection system?

MR. BURTON: Yes. In fact, I was the team member who actually did look into fire protection. One of the questions that came up earlier had to do with the fire water tanks. I do want to say that as part of that inspection, I did go down and look at some of the videotapes that they took at the inside of the tanks. What they did was they did an inspection of the tanks back in '91 and observed that some of the coating was beginning to break down into grade and looked at some of the condition reports that followed from that.

And then they did it again in '99 and actually observed those tapes. There was some -- you could see the decomposition and some of the debris in the bottom. But, as Mr. Baker had said, they are actually in the process of -- they are going to be recoating the tanks in the near future. And those were the original coatings.

MEMBER POWERS: Did they have to re-flush? Did the fire water dispersal lines

MR. BURTON: I believe that was probably part. I know when they emptied the tanks, I believe

that was part of the entire thing. Procedurally, they do that.

One of the things that the Committee is interested in is comparing applications. Obviously because this is the first BWR, there is particular interest in whether there are in particular any new or unique aging effects that BWRs are subject to versus the Ps. The staff did pay particular attention to that.

Now Southern Nuclear took a commodity approach in that rather than just looking system by system, they actually identified what materials are we looking at, and in what environments are those materials operating, commodity groups.

As such, what we found was that there are no unique materials. The materials are not being operated in any kind of unique environment. As a result, we did not see any new or unique aging effects. In fact, in the application there is an Appendix C-1 that really speaks to aging effects and some of the consequences of that. But we did not find anything new. So in that respect, we really don't expect the BWRs -- we don't expect to see anything unusual compared to any of the PWRs.

MR. GRIMES: This is Chris Grimes. I want

to emphasize that we did see uniqueness relative from application to application. But when Butch says we didn't find any new aging effects, remember that that's drawn on the nuclear plant aging research program that began over a decade ago. I would have hoped that we would not have found any new aging effects in this application. So that was reassuring.

But we did learn some process lessons in terms of the way that the information was packaged. Specifically, with respect to commodity groups.

MR. BURTON: And actually to follow on on that, to talk about some of the other differences that you may see compared to some of the previous applications. As Chris said, it really was the uniquenesses were really a matter of process and packaging I guess you would say.

As you now know, it's the first to use the BWRVIP reports, which we have already discussed. It was the first to use a functional approach versus a system approach in the scoping process.

Now what do I mean by that? What Southern Nuclear did was they looked at every single system in the plant, identified all of its functions, and then bounced the functions off of the scoping criteria. So what you see is not a direct correlation between the

system and whether it's in scope or not. What you see is the identification of the in-scope function, which was I think a little bit different approach.

Then finally, Southern Nuclear as you all know, there are 10 program attributes that are assigned as criteria to evaluate the aging management programs. Southern Nuclear took a unique approach in that they took the 10 program attributes and applied them to a demonstration of adequate management.

Probably the best way to do it is to show you what I mean by that.

CHAIRMAN APOSTOLAKIS: This "functional versus system approach" what does that mean? Even if you look at the system, you look at its function, right?

MR. BURTON: Yes.

CHAIRMAN APOSTOLAKIS: So what's the difference?

MR. BURTON: The difference is that normally you would look at a system and you would say does the system directly meet what turns out to be the eight or nine questions that constitute the scoping criteria. Probably the best way to do it is to give you an example.

Main steam. Main steam, most of us think

that would obviously be in scope. But what actually happened was they looked at main steam and looked at each of its functions, and which of those functions would actually meet the scoping criteria. As it turned out, for main steam the in-scope function was contained in isolation.

So that is actually what brought the system into scope, but it was actually that particular function. In fact, maybe this wasn't the best example, because what we also found was that as they looked across systems, you found certain functions that were common across a number of systems. What they chose to do was to actually pull those functions out and group them separately. Containment isolation was one of them. Because it cut across so many different systems, they have a specific category for the containment isolation group C61.

Another one was reactor coolant pressure boundary. That function cut across a number of systems. It was actually pulled out and categorized separately. So it was really a function-based assessment.

CHAIRMAN APOSTOLAKIS: That's not very clear, but at least we are making progress.

VICE CHAIRMAN BONACA: We commented quite

a bit during the subcommittee meeting that that created a lot of difficulty for reviewers, particularly when the people on the subcommittee had to review it because you have a system that you presume just because there will be scope, then you are looking at it, you don't find a description of the system up front. Then coming through this, you just don't find it. You have to search through these functions, for example, that it perform a containment isolation, then you find an element of that system. So you say well wait a minute now, are the other pieces of that system out of scope? A lot of the questions in the NRC had to do with that. The answer is no, they are in scope. They are somewhere else.

So it made it very confusing, I must say. But I think that ultimately, you learn to do it.

CHAIRMAN APOSTOLAKIS: This is a good step forward. If you keep it up, eventually you will rediscover PRA.

MR. BURTON: Okay. Let's go on.

MEMBER POWERS: We're busy trying to decide whether that's a good rediscovery or a bad rediscovery.

MEMBER SHACK: If you didn't put in core damage frequency, George, it wouldn't exist.

MR. BURTON: Oh boy. What Dr. Bonaca just spoke about, we spoke about that extensively at the subcommittee meeting. We reached a consensus that these issues are what we call navigational issues, being able to see your way through the application. There were several challenges in that respect.

This is an example, this is in the application, in one of the appendices, called the Aging Management Program Assessment. What Southern Nuclear did was they looked at each commodity group and each aging effect for that commodity group. What they did was they took the ten attributes, as you see over here on the left, and actually showed where the program coverage was for that, which was actually very good.

It wasn't what we normally see in terms of how the 10 program attributes are applied. I should say that the navigational -- the RAIs that came out having to do with navigational questions, and we had a number of RAIs because we didn't see how the ten attributes were being applied directly to the programs. We had a number of RAIs that came out as a result of that. By my estimate, probably a third of the RAIs fell into those groups.

We issued the safety evaluation report.

We had 18 open items. Obviously we have had ongoing dialogue. At this point, we have four that are under appeal. I need to explain what that is.

With the license renewal process, we allow for situations where if we don't seem to be making progress at the working level, we have a series of appeal meetings that start at the branch chief level and move ahead, to try and resolve those issues.

Right now, of the 18 open items, we have four that are under appeal. In fact, one of my takeaways from the subcommittee meeting was to give you the status because when we had the subcommittee meeting, the following day we were going to have the first of the appeal meetings. So the next slide, I'll be speaking on that.

So we have four under appeal now. That's not to say that that's the be all and end all. As we continue our dialogue at the working level, if we find additional items that need to go into appeal, we'll start to do that.

Of the 18, five are now in a confirmatory status. What that means is that the staff and Southern Nuclear, we have reached agreement but we haven't dotted all the Is, crossed all the Ts. It's not official yet. So until then, it is actually

confirmatory.

CHAIRMAN APOSTOLAKIS: Who is the ultimate authority regarding appeals, the one that says this is it?

MR. BURTON: This is it? Well, I'll let Chris speak to that.

CHAIRMAN APOSTOLAKIS: Chris?

MR. GRIMES: I don't think that highly of myself. The ultimate authority would be the Commission. If an individual applicant isn't satisfied with the staff position after it's addressed at the branch level, we go to the division level. Then we go to the office level. Ultimately, the issue could go up through the EDO to the Commission if it were significant enough.

Most of the issues of industry concern that got to that kind of strategic level, I think were revealed in the credit for existing programs issue that went to the Commission and instruction the Commission gave us in terms of how to offer the industry an opportunity to take credit for existing programs, which is the way that it was phrased.

So we'll discuss that a little bit further in the next meeting, where we talk about the improved renewal guidance.

MR. BURTON: I did want to -- I didn't write down all the items that are now confirmatory, but I did want to give you an idea.

One of the open items that we had was we asked for a one-time inspection for the fuel oil tank bottoms. That was on the table. We since learned that they had actually already done such an inspection, and have actually given us the result.

They had actually dug up and inspected one of the four big EDG fuel oil tanks, and found that there was very little reduction in thickness. That argument also carried over into their two smaller fuel oil tanks for their diesel fire pumps.

So we got that response fairly quickly because they had already done it. So that's basically closed, but again, we haven't done all the official paperwork.

Another one is the complex assembly issue. If you remember, that issue came up with Oconee. That was actually resolved. We developed an approach to resolving that. Initially it was not clear that Southern Nuclear was taking the same approach. But since then, we have clarified that they are going to be doing the assessment similar to Oconee.

MEMBER SIEBER: You are talking about

skid-mounted equipment?

MR. BURTON: Yes.

MEMBER SIEBER: That means you treat individually each component or sub-component on the skid?

MR. BURTON: Yes. The complex assembly issue, as it arose at Oconee, had to do with the diesel generators, which are active components. But in addition to the diesel, you had skid-mounted auxiliaries. Should they be considered part of the active assembly and therefore not subject to an AMR or not?

MEMBER SIEBER: Right. That was resolved, that they are now treated separately. For example, transformers and like components, piping?

MR. BURTON: That's right. We found from Oconee that it was really not appropriate to lump the skid-mounted auxiliaries and treat them as if they were all active, to actually do an assessment separately.

Again, initially it was not clear to the staff whether Southern Nuclear at Hatch was taking the same approach, but we have since clarified that they will be taking that approach.

MEMBER SIEBER: One thing that I found in

a number of plants is that often licensees do not identify with mark numbers valves, heat exchangers, and other components in the skid package. For example, the generator hydrogen seal oil system might have 50 valves in it. It's mounted on a skid, on a bed plate. It has one mark number.

Is that the condition at Hatch? Does anybody know? Or do you have individual mark numbers for all the components or sub-components on the skid?

MR. BAKER: Certainly for the two items that are the subject of the open item, which are the diesel generator and the hydrogen recombiner, we specifically know all the sub-parts of those skid-mounted assemblies.

MEMBER SIEBER: But other ones, you don't know?

MR. BAKER: I'm not aware of anything that would be in the license renewal envelope that would meet that. What you say is probably true for parts of the plant that are not in the scope of license --

MEMBER SIEBER: Seal oil, some chillers, for example?

MR. BAKER: Yes.

MEMBER SIEBER: The chillers often are skid-mounted thing. A lot of times, they are safety

related.

MR. BURTON: A couple of things that I did want to point out. One had to do, we touched on it earlier, had to do with inaccessible components, buried and the like. One of the things that we emphasized when we went down on the AMR inspection was to understand exactly how these things are identified and taken care of procedurally. In fact, as a result of the inspection, what we have is -- well, they have an excavation procedure. They have in the proposed draft form, a mark-up of that procedure which actually says when you are either burying up components or if you are digging around a structure, they actually have the hooks in the procedure to actually take you to the appropriate aging management programs to do the inspection.

Another thing that I wanted to talk about scoping issue, in the past the Committee has had questions about design basis events, and what is the population of events that you are looking at to determine what's in scope.

Because of the functional approach to the scoping, as I mentioned before, the staff is not real clear on exactly how they identified the design-basis events. As it turned out, at the time that they

submitted the application, they had a draft version of what they called the nuclear safety operational analysis, which has since been incorporated into the FSAR.

This analysis was a comprehensive look at the design-basis events. Even though it was in draft form and they didn't take specific credit for it in the application, it was a part of their general review in their scoping process.

Since then, the rule requires an annual update to the application based on any changes to the CLB. So we actually caught the NSOA as part of the annual update. As a result of that, they actually brought in -- the only thing that was brought into scope that wasn't there previously was the rod block monitor. So that was taken care of also.

VICE CHAIRMAN BONACA: But you didn't go through every indication that all the components for the scoping match the one in the design-basis, or did you?

MR. BURTON: Well, okay. If I speak to your question, maybe this will address it. One of the things that is important to understand is exactly how the staff approaches its review.

The application identifies things that the

applicant has identified as being in scope and subject to an AMR. Obviously we look at that. But a large part of our review is to look at the things that the applicant decided was not in scope and was not subject to an AMR to see if there's anything that was in that population that actually met the scoping or the screening criteria and to bring it in.

Was that getting at your question?

VICE CHAIRMAN BONACA: I think so, because I know also that you took three systems.

MR. BURTON: Yes.

VICE CHAIRMAN BONACA: And for those, you went through what I would call a painstaking verification that everything which had to be in it would be. So that audit I guess provides the level of comfort.

MR. BURTON: That is correct.

We have had two inspections at Southern Nuclear so far. The review process allows for three. We have done two. I have spoken already about the AMR inspection, which was the second inspection. The first inspection, which we did back in September, was the scoping inspection. Again, because of some of the navigational issues that the reviewers were having and again, the functional approach to the scoping, when we

went down to the scoping inspection, we actually took several systems and actually walked through step by step from beginning to end how you identified their functions, how you bounced those against the scoping criteria, how you evaluated the evaluation boundaries, and how you did the screening. So we walked through several systems step by step.

What we found was that talking with their engineers, we were comfortable that they were doing things properly, but we found procedurally it wasn't real clear. It didn't take them through step by step exactly what to do. They were doing it, but the procedure didn't really match.

So one of Southern Nuclear's takeaway from our scoping inspection was to update the procedure to make it less goal-oriented, which is how it was originally, and make it more prescriptive. In fact, we went down later to confirm that they had made those changes. In fact, they had.

MR. GRIMES: This is Chris Grimes. I would like to clarify. There are two aspects to the staff's evaluation basis for scoping. There's the inspection that looks at how the scope verifies that the scope of equipment matches our understanding, our safety evaluation basis. But we separately conduct a

methodology audit. I think it was during the audit that we identified the procedural weaknesses.

But the audit looks at the process and verifies that there is a completeness aspect to the process that the applicant uses so that we don't have to rely simply on our sample of results in order to develop a conclusion about the completeness of the scope.

MEMBER WALLIS: I asked you about scope by way of an example, take say spent fuel pumps, look at spent fuel pull section of the Hatch application. You find a lot of stuff about boring things like anchors and bolts and structural steel and so on. What about the function of the pool? The pool shouldn't leak. What is there that assures it shouldn't leak? It has a liner, I believe. It's not in scope. It's not in scope presumably because something else takes care of it. Is that what I conclude from this?

Only the boring things are in scope. The things that really matter don't seem to be there. Why?

MR. GRIMES: This is Chris Grimes. I would first like to start off by observing that Dr. Wallis is obviously not a civil engineer.

(Laughter.)

It wasn't boring to --

MEMBER WALLIS: I'm one of the most civil members of the --

(Laughter.)

I think that is something that when you first look at it, strikes one. That doesn't mean it's not really a question of civil versus mechanical or something. The things that are picked out to be in scope are the things which one would sort of least expect to fail, so something must be happening to take care of all the other things.

What is that something?

MR. GRIMES: Mr. Baker should address the Hatch specific. Then I'd like to address the generic aspect.

MR. BAKER: I think what you are seeing here is what Butch was referring to as one of those navigational things. In reality, the spent fuel pool liners are in scope.

MEMBER WALLIS: They are?

MR. BAKER: Yes, sir.

MEMBER WALLIS: They don't appear in the spent fuel section as being in scope. You have to find them somewhere else?

MR. BAKER: I'll open up the book and show

it to you during a break. But it is in scope, yes. We consider that important as well.

MR. GRIMES: And from a generic point of view, we learned a lesson on Calvert Cliffs and Oconee on articulating what is in scope for spent fuel pools. You may recall that Chris Gratton spent some time trying to explain why the cooling function is not considered a design-basis function for the purpose of license renewal because the staff relies on the capability for the pool to be able to maintain its geometry, even with the loss of cooling. So the cooling function was explored most extensively during the first two applications. Then we have refined the guidance to look for those things that are really important to the boundary integrity of the pool and the ability to maintain the coolable geometry.

So I think that when we learn some more packaging techniques and some more plain language lessons, I think that you will find that all of the really interesting stuff is buried within those civil structural kinds of details.

VICE CHAIRMAN BONACA: And also I would like to add in addition to that's true that your cooling system was not in scope, but your make-up -- you had a make-up capability which was a safety grade

and was in scope that would allow you to make up inventory in case you were losing the cooling capability.

So the basic functions are assured. That was the whole --

MEMBER WALLIS: Maybe it's a problem with the way the thing is organized. The function of cooling is somewhere in the report. I look up fuel pools in the part that was assigned to me to look at, it's all about acapults. But somewhere else, someone else is reviewing the cooling, which makes it difficult to get the perspective on how you handle the fuel pool.

MR. BURTON: Now you see some of the challenges the staff had. This all falls under the category that I spoke about before regarding navigational problems. So yes, if there is anything specific, we can probably get you to the right place.

As I mentioned, there were four items that are currently on the table as subject to appeal. We had the subcommittee meeting on March 28th. We had the appeal meeting the next day on the 29th. So one of the takeaways from the subcommittee meeting was to report back and see exactly where we stood as a result of that meeting.

So what I have done is I have taken the four issues and tried to put them in a simple question format. The first one was should the draw-down test that's required by the technical specifications be credited as an aging management program to confirm maintenance of reactor building in leakage limits.

One of the things that the staff was concerned about during the period of extended operation, how will Southern Nuclear continue to maintain their controlled in-leakage for the reactor building. What was on the table was that all of the inputs to controlled in-leakage are going to be managed through inspections and corrective actions, the penetrations, all of the structural elements.

Our question was well, that is somewhat of an indirect measure of whether it's actually going to do that. I guess one example of that, and I am going to go back to my ABWR days, is that one of the items that they looked at concerning turbine building flooding was they monitored pressures for service water, surf water, things like that, and that a drop in pressure would be indicative of a large leak and subsequently flooding in the turbine building.

One of the questions that came up is suppose you had leakage that wasn't quite enough to

reduce the pressure to the point where you got the low pressure actuation. You get all this flooding in there, but there's nothing instrumentally to tell you that.

So we said okay, well what's the direct measure of flooding, level. Okay. That was one of the things that we came up with.

Similarly here, you can look at all of the inputs to in-leakage for the reactor building, but it is somewhat indirect. The way you can tell most directly is to measure the draw-down, for which we do have a tech spec.

Southern Nuclear was saying that is a very gross test. In order for you to see anything as part of that drawdown test, you would have to have substantial degradation in the penetrations and things like that, which we would catch by our existing aging management programs far before they would degrade to that degree.

So as a result of our discussions, we felt like probably the best thing is to have a combination of the two. To have the inspections and the ongoing corrective actions when you saw a problem, along with the drawdown is a confirmatory sort of test.

So that is where we are with this right

now. Still dialogue going on, but --

VICE CHAIRMAN BONACA: Confirmatory still would put it into the aging management program as part of it?

MR. BURTON: Yes.

VICE CHAIRMAN BONACA: Okay.

MR. BURTON: Number two --

MR. GRIMES: Actually, Butch, in the interest of time, make sure that we get through the whole presentation and try and stay on schedule. I think it would be fair to categorize all four of these things as ongoing dialogue, haven't made any decisions. We need to make sure that we clearly understand what the true value of the drawdown test is. We need to clearly understand the current licensing basis treatment and categorization and bookkeeping associated with category II piping with respect to the seismic II/I issue.

VICE CHAIRMAN BONACA: We would like to hear something about that issue however, because you know, a face value seems as if those components should be in scope. But I understand that there are issues to do that maybe too much of the piping was placed, was evaluated as a II/I and shouldn't be. So there are other things we don't understand.

MR. GRIMES: And that is the point that I want to make. At this point, on all four of these issues, I know I do not have enough information to make a decision. I think the applicant and the staff both went away with an understanding that we need to talk some more because we do not know the whole story. On the seismic II/I, it was clear from the nature of over an hour's dialogue that we still do not have a very clear understanding of how the applicant treated the design capability for postulated breaks in category II piping. We need to understand that before we can move forward on that issue.

VICE CHAIRMAN BONACA: Wouldn't that be a significant expectation of the guidelines you have established if you had to say that now there are seismic II/I components that do not fall into -- I mean there is a --

MR. GRIMES: Yes. I would say there's fundamentally a violation of the current licensing basis if we don't capture the capabilities. We have a semantic problem because the piping is not in scope. The criterion in the license renewal rule says the failure of components whose -- the postulated failures of components whose failure could affect safety-related piping or safety related functions.

If you have included the pipe whipper strength in scope, do you now have to postulate that the piping fails in a different way? Do you have to inspect the piping to make sure that the pipe whipper strength prevents the failure that it's going to impact the safety function?

The pipe wasn't in scope. The restraint was in scope. So this gets back to the problem that we have communicating with this commodities approach because you looked for a system. Your paradigm was built on the way that we normally do system reviews. But their communication package is different. It looks at functions. This gets back to Dr. Apostolakis' point earlier. That is, we have backed into a new way of categorizing that is more in line with the way that PRA analysts look at things.

But in terms of our ability to clearly articulate how aging will be managed so that the current licensing basis will be maintained for the period of extended operation, what I observed on the 29th was two groups of people talking past each other, because they were talking from a different paradigm of how they packaged their scope.

VICE CHAIRMAN BONACA: What about the housing? The housing, will it be covered by your

complex assembly definition, which has been in this position previously.

I mean all I'm trying to say is that I think that maybe there are ways to, for example, for the seismic over one, one could conclude that elements have to be in scope, and then accept a modified or a known existing accident management -- I mean aging management commitment because of special circumstances. Are you exploring the possibility? I mean that would be one way to maintain the commitment to II/I, but the recognizing as you always do that in some cases, you don't need the specific problem.

MR. GRIMES: That's why I jumped in and tried to cut short the debate over the issues because I know that on all four of these things we only have half a story, and that we clearly need to have more dialogue with the applicant in order to achieve a shared understanding about whether or not we disagree about anything.

On the housings, I believe that we made our point more clearly to the applicant in terms of what our expectation is. We discovered that housings to some are not housings to all, and that they now better understand that we are not violating the Commission's tenets of going into piece parts. We

need to develop some guidance beyond what we are going to tell you at the next presentation about improved renewal guidance.

We need to develop some improved guidance on making this distinction between complex assemblies that are on skids and separating out active and passive functions of components, which is a piece parts issue. They sometimes get described using the same terminology.

VICE CHAIRMAN BONACA: I asked for this presentation if you remember last week, because I thought that you expressed an interest in having our position on these four items. Are you still interested in having our position on the fourth or not?

MR. GRIMES: After the meeting that we had on Thursday, I think that I would say not, because I think that we owe you an explanation about what it was that we decided that we wanted to argue about. We may be in a position soon when we come back to the subcommittee with the explanation of the resolutions, we may want you to express a view about whether or not the pipe-break criteria are time-limited or not, because of the explanation that the applicant gave us about how they were used as a screening tool for

design, and that they do not actually -- they are not limited in some way.

But even on that issue, I think that we need some more dialogue in order to understand what the regulation envisioned as a time-limited aging analysis. So at this point, I don't think that you have enough information to give us an informed opinion on these issues, because I know I don't.

VICE CHAIRMAN BONACA: Okay. Thank you.

MR. BURTON: That's all I have.

MEMBER WALLIS: I have a question for you now. I thought you were going to talk about the SER. So I want to ask you a big picture question. This slide with the four appeal items sort of supports what I want to say.

I read the SER. A lot of it is simply repeating what's in the application. Then there's the staff evaluation. The staff evaluation seems to consist of saying something is within scope. The applicant has identified this component subject to an AMR. There's some AMP here and this other thing is a TLAA, which is what your appeal issues are all about.

Okay. There's a procedural thing, it seems to me. You are now saying we are going to consider this, this, this, and this.

The big question is is the AMR good enough? Are the components that are subject to review really going to last another 20 years? All these questions don't seem to be addressed because there's all this stuff about procedure. Is this in scope or out of scope? Is it a TLAA? Is this AMR? You know, that's okay, that's fine. But that seems to me is the preliminary to now evaluating the quality of all these things for the purpose of license renewal.

MR. BURTON: Do you want to --

MR. GRIMES: I'll take it. It's in my job description. The staff did exactly what we asked of them in terms of prepare a safety evaluation that addresses the requirements of the rule, because the Commissions said that the rule is the predicate upon which they develop a basis for granting a renewed license.

I would say that we looked very carefully during the concurrence review to make sure that for scoping, it specifically says there is reasonable assurance that everything that needs to be in scope is in scope and it's based on an explanation about what was looked at.

There are statements in the safety evaluation that precede the we have reasonable

assurance that aging will be adequately managed for the scope that talk about we conclude that the program is effective or that there's experience that demonstrates that it works or things like that.

Actually as I was reflecting on the challenge that you offered before concerning could we put the reasonable assurance finding in more plain English. I was thinking to myself now where in the NRC, where in the agency would I go to get a really good explanation about what the reasonable assurance finding means in plain language that I could use to convince the public. It occurred to me that the best qualified group would probably be some advisory committee to the Commission.

(Laughter.)

As we proceed to try and develop a plain language version of our traditional safety evaluation findings that more clearly explains why the Commission felt that managing aging for the stuff that's in the CLB that is relied on to prevent or mitigate accidents or protect against station blackout or all the rest of the stuff that the Commission determined was important, will continue to look for ways to express that in language that the general public, the folks that attended the workshop yesterday with Mr. Cameron

and the public participation interests, as we find ways to try and articulate these things so that they can better understand what we are really trying to tell them, then we'll evolve those into improvements in the style guide for our safety evaluations.

But at this point, the language construct was based primarily to have everything in the regulation covered. We'll try to look for ways to improve on the clarity of that finding.

MR. BURTON: And I guess I just wanted to add to that, because I'm not exactly sure what parts of the application we're looking at. But certainly in section 2, the scoping and screening, the primary thing was to ensure that all the right things are being captured.

Section 3 is more the assessment of the adequacy of the aging management and things like that. I don't know if you as part of your review included section 3. If it did and if there's some question again --

MEMBER WALLIS: Yes, I did, and section 4 too.

MR. BURTON: In section 4, the TLAAs.

MEMBER WALLIS: So maybe what I'm asking questions, might have some influence on how you finish

up writing the SERs so that it is clearer. That you haven't just gone through sort of putting things in boxes. You have actually done some really digging in, convince yourself that things are in good shape.

MR. BURTON: Sure.

MEMBER LEITCH: I have two quick questions. I guess they are really for Mr. Baker. A number of BWRs are in the pipeline going to be asking for power uprates. Is that in the Hatch plans?

MR. BAKER: Hatch has done the extended power uprate on both units.

MEMBER LEITCH: Is that five percent order of magnitude or was it one of those larger ones?

MR. BAKER: Go ahead, Chuck, if you have the numbers.

MR. PEARCE: Charles Pearce, Southern Nuclear. The first uprate we did was five percent, 105%. The second uprate was greater than five percent. I'm not sure about this number, but I think it was eight percent. So we did 105% uprate and then we did another, about eight percent uprate.

MEMBER LEITCH: So you see, Hatch is being at its ultimate capacity now?

MR. PEARCE: Well, I can't speak to whether there's going to be a further uprate plan or

not. I think we don't have any plans in the immediate future, let's put it that way.

MR. BAKER: The original license was 2436 megawatts. We're currently talking 2736 megawatts. So that is the extent of the uprate.

MEMBER LEITCH: And the other question was do we know what the core damage frequency is for the Hatch units?

MR. BAKER: We have that. Chuck, if you can find it before I can. I have it in my notes.

MR. PEARCE: The core damage frequency, the total is 1.22 e to the minus fifth.

CHAIRMAN APOSTOLAKIS: When you say total, what do you mean?

MR. PEARCE: That includes the frequency from all the events.

CHAIRMAN APOSTOLAKIS: External as well? External events?

MR. PEARCE: The external events, you are talking about the earthquake, fire? That, I do not know. I'm not a PRA expert. I just have the total. I don't believe it includes external events, but I can check into that in the break.

MEMBER LEITCH: And that's the same for both units?

MR. PEARCE: Yes. It's in that ballpark for both units.

MEMBER LEITCH: Thank you.

VICE CHAIRMAN BONACA: Okay. Any other questions?

MEMBER WALLIS: Those where there's no, what will it be in 20 years? Do you make any predictions like that? There must be some effect of aging.

CHAIRMAN APOSTOLAKIS: This is not in the PRA.

MR. GRIMES: This is Chris Grimes. But we have been periodically checking with the Office of Research. I understand that they do have some model, aging models for PRAs that they are continuing to try and develop, but they are not ready to try and roll them out yet. But we have continued -- we will continue to monitor the research programs because we are looking forward to an opportunity at some point in the future where we might be able to see a risk model for age, for a plant age.

VICE CHAIRMAN BONACA: All right. Are there any more questions for Mr. Burton or for any of the presenters? There are none, so Mr. Chairman, I pass it onto you.

CHAIRMAN APOSTOLAKIS: Thank you. We will recess until 10:55, with a narrow factor of three.

(Whereupon, the foregoing matter went off the record at 10:40 a.m. and went back on the record at 10:58 a.m.)

CHAIRMAN APOSTOLAKIS: The next issue is proposed final licensing guidance documents. Dr. Bonaca is still the leader.

VICE CHAIRMAN BONACA: Thank you, Mr. Chairman.

In November of last year, we wrote a report with comments on the license renewal guidance documents. At that time, we had reviewed in draft form. Since that time, also the industry and the public has had an opportunity to provide a lot of comments to the NRC. The staff has now updated those documents, essentially the SRP, the reg guide, and the GALL report, to address those comments.

They have written them now in a final new reg form. I mean they have assigned new reg members and reg guide number to it. They have presented it to the subcommittee last March 27th. We are here to review them and to provide recommendation if possible on whether they should be finalized and other issues.

With that, I will begin to introduce Mr.

Grimes.

MR. GRIMES: Thank you, Dr. Bonaca.

Yes, by way of introduction, we drew from the subcommittee meeting a desire to make clear to the full committee that we believe that the substantial amount of effort has gone into improving the guidance for the conduct of license renewal reviews and understanding of the attributes of effective aging management programs.

The staff is going to describe highlights of those features for you. But I want to emphasize that we continue to rely on the foundation of the renewal rule, which relies on the regulatory process to provide for the unforeseen. We are certainly going to have new experiences in the future, and may reveal new aging effects or may, like the core shroud cracking that you just discussed, a decade from now, something else is going to occur. We have a process to impose new generic requirements when we learn new lessons in the future.

The whole theme of this activity to develop generic aging lessons learned has been a focus on process, on providing the tools to the plant owners so that they will continue to find and learn and correct as they go, because these programs aren't

going to start until more than a decade from now. Then they go 20 years beyond that point. So we are looking way out into the future in terms of the expected behavior changes that result from these regulatory requirements.

You also asked us to present a judgement on the potential erosion of the safety margin. This gets back to the conversation that I struggled with Dr. Wallis' challenge to try and articulate a safety conclusion.

Recognizing that there's constant growth of knowledge, this process approach fundamentally relies on an ability to continue to maintain an adequate margin of safety. That doesn't necessarily mean that the margin is larger or smaller or better known or less well-defined. It really gets to the individual inspection and maintenance activities that learn and grow and adjust according to what is understood about the impacts on margins.

In some cases, we learned things that cause us to take margin away because we think we're smart enough to know how to reduce the margins. In other cases, we recognized that the uncertainties are growing, and so we provide additional conservatism in the way that we manage the plant design. So we

increase the margins of safety where we learn that we do not know enough.

Trying to find a simple way to articulate that in plain language will continue to be a challenge. So there are still issues that we will pursue for future improvements in this guidance. But we believe that, and I mentioned before, more than a decade of nuclear plant aging research that's actually going on the 20th anniversary of the NPAR program, about a decade's worth of experience in trying to do license renewal reviews, we think that the guidance is now sufficiently mature that the Commission should approve it for implementation on all future renewal reviews with the recognition that we will continue to add to it as we learn new lessons in the future.

Our hope and expectation is that after we have made this presentation, that the ACRS will agree that it is more than adequate for this purpose, and should endorse it with the Commission.

VICE CHAIRMAN BONACA: One last note I would like to make. Before the meeting, this presentation is over, I would like also to hear about the commitment that was made in the response to our previous letter that the GALL report to be updated with some frequency I understand? At the time, there

was a commitment made but no procedures or specific processes established yet. Maybe you could comment on that at the end of the meeting?

MR. GRIMES: I'll do that.

VICE CHAIRMAN BONACA: Thank you.

MR. GRIMES: I'm sorry, and I was supposed to say and now I'd like Dr. Sam Lee to introduce the staff's presentation.

MR. LEE: Good morning. My name is Sam Lee. I'm from the License Renewal and Standardization Branch, NRR. This is this morning's agenda. After my introduction, Jerry Dozier is going to talk about some examples of the public comments received. Ed Kleeh is going to talk about certain NEI continued items. Dave Solorio is going to discuss the one-time inspections.

The improved license renewal documents consist of the generic aging lessons learned, GALL report. With that document is an evaluation of aging management programs -- references to GALL report to focus to staff review in areas where the programs are evaluated, and a regulatory guide that endorses NEI document 95-10 that provides guidance to licensing applicant in preparing their application.

This has been a significant agency effort involving staff from the Office of NRR, including the

staff that are doing the license renewal application review. Also, the Office of Research. On my left, Jit Vora is a team leader from Research. Contractors from Argonne National Lab. On my right, Young Liu is the project manager from Argonne. Also from National Lab, on my left Rich Morante. He is the project manager from Brookhaven.

We are preparing a SECY paper to the Commission submitting this document for the approval by the end of the month. During our interaction with NEI to discuss the public comments on the documents, they identified five items for further discussion with the staff after the issuance of these documents. After we discuss these items with you later today, we'll continue a dialogue with NEI on these items. The result of any additional guidance of clarification will be incorporated in a future update of the documents.

In addition, when new technical information and new operating experience becomes available, and also when the staff reviews additional applications, and what we learn, we will incorporate into future updates of these documents.

NEI indicated to us that the applicants that will be submitting the applications next year

will be using these documents.

So to address how these documents ought to be applied, NEI is conducting a demonstration project in which they are preparing sample portions of an application and submitting them for staff review and comment. They are scheduled to submit this by the end of the month. We'll be working with industry through this demonstration project over the details for the implementation for procedures.

That concludes the opening remarks. If there's any questions? Okay. Jerry Dozier will go into the public comments.

MR. DOZIER: Good morning. My name is Jerry Dozier. I'm from the License Renewal and Standardization Branch. With me, I have Mike McNeil from the Division of Research, Barry Elliot from the Division of Engineering, and Omesh Chopra from Argonne National Laboratories.

There were over 1,000 comments that were on the improved regulatory guidance. This slide just represents some of the ways in which we evaluated the comments and tried to incorporate them into the GALL report, primarily chapter 4.

For example, in the first bullet, there was a lot of discussion and a lot of debate and a lot

of comments on where is the threshold for radiation-assisted stress corrosion cracking, void swelling, where is this threshold? Is it 10 to the 17th, 10 to the 21st, somewhere in between?

What we did though is really what the staff wanted, is to have an effective aging management program. What we wanted to do was to find the components that had the most susceptible locations. We wanted to monitor and inspect with an effective inspection technique those locations. That was really the aging management program we wanted.

So by getting rid of the threshold, we got rid of a lot of the comments and a lot of the debate, and uncertainties. We came out with an effective aging management program, which is what we really wanted in the first place.

On the second bullet, any unmade comments that in the GALL report, in earlier versions, if we could credit a program, we would credit. For example, in boric acid corrosion, you could use the regular boric acid corrosion program and you could also credit ISI. Any IS that we provide only a minimal acceptable, the boric acid corrosion program has been effective in the current term, and we expect it to be very effective in the extended term, so we

accommodated that comment by only referencing the minimum program.

VICE CHAIRMAN BONACA: But I thought the GALL was also a means of providing alternatives to minimum programs.

MR. DOZIER: What the GALL report primarily gives you is one acceptable program. It may not in all cases be the minimal program, but it is an acceptable program that primarily we have in the past through Oconee and Calvert Cliffs, if we could say it on a generic basis that this was an acceptable program, that is what you really see in the GALL report.

We don't want to limit the creativity of the licensee. If they have a more effective methodology, of course in the application they can propose that on a plant-specific basis for us to review. The limitation being that they couldn't reference back to the GALL report in that case.

MEMBER WALLIS: What does "fully credited" mean? I don't understand that.

MR. DOZIER: As I was talking about earlier, for example, we would have the component, some carbon steel component here. Then we'd have the aging effect would be boric acid corrosion. Then we

would credit two programs. We would say ISI was effective in finding it, and also would say boric acid corrosion. We would put two. In this case, we only have one.

MEMBER WALLIS: Credited means that the programs take care of your concerns with the issue? Is that what you mean?

MR. DOZIER: Yes.

MEMBER WALLIS: It resolves the issue then?

MR. DOZIER: It resolves the issue, yes. It would be fully acceptable. By fully credited, I guess I should have made to this have said fully acceptable to the staff.

MR. GRIMES: Actually, you can drop the fully and it still means the same thing.

MR. DOZIER: In the next bullet, the earlier versions, for example, the pressurized bottom head, we had those as plant-specific evaluations. In that case, the applicant could propose a program. Well, during our revisions and incorporation of the comments, we started really focusing on trying to give as much information to the applicant as we could. In other words, now for the bottom head we credit the chemistry program and ISI and tell the applicant that

we're only concerned with the Iconel 182 welds. So it gives the applicant more direction on really what the staff's interest is.

In the GALL report, of course you'll have a component. You'll have many aging effects. Sometimes in our public comments from the earlier version, there may be one of the aging effects that there was some controversy on whether or not that was really a significant aging effect or not, or really applicable.

In some cases we would remove based on the comment and further evaluation, we would remove some of the aging effects. Does that mean the component went away? No. That meant just the aging effect.

In the last bullet, of course GALL is a useful tool for the applicant to reference during the license renewal application. We based ours on the Oconee and Calvert Cliffs, and may not have gotten the full range of components that they could possibly be done on a generic basis.

So NEI provided us with some additional components that they would like to have in the GALL report and the programs. We evaluated those and accommodated those types of requests.

Also, in the case of there was comments

from, for example, Union of Concerned Scientists. They had a few components to add. We also accommodated those requests.

So there were many comments, and these are just some of the ways that we evaluated and accommodated the comments. Is there any questions? If not, I'd like to turn it over to David.

MEMBER WALLIS: So there were no serious comments that really changed your mind about anything, were issues that couldn't be handled this way? I get the feeling everything worked out fine with the public comments?

MR. DOZIER: I may have made it sound a little easier than it was because there was -- we had several comments we went through. We even had to go through the escalation process up to the branch chief. So everything wasn't easy. But we tried to address the best we could.

Barry has something to address on that.

MR. ELLIOT: We have open issues. Don't think we don't have open issues. We have open issues. We are still going, you know, trying to resolve those open issues. This is just the issues that we were able to resolve here, but there are still open issues between the NRC and industry.

VICE CHAIRMAN BONACA: I hope the GALL report doesn't become a minimum requirement document. I mean it wasn't intended to be that way.

MR. ELLIOT: We don't look at it as a minimum requirement document either.

VICE CHAIRMAN BONACA: I'm only saying that there were some comments that said encouragement for the staff to put in only the minimum that's accepted for some programs.

MR. ELLIOT: I can clarify, the in-service inspection discussion a little bit. The reason we put the boric acid corrosion in is because we weren't satisfied with the in-service inspection program section 11 for corrosion, so we put in this program. That's why we're taking credit for it, because we told them that this is what we wanted.

VICE CHAIRMAN BONACA: I understand. My comment only is because I view over time these would be probably the main document reference both by the applicants and the staff. So we have seen the first applications involving a significant effort of the applicants to be creating. I mean first BG&E had to do a lot by itself. Here this is becoming more and more important because it is going to be the baseline for the applications.

MR. GRIMES: Dr. Bonaca, I am compelled to say that by virtue of the Commission performance goals on effectiveness efficiency and knowing that necessary burden and so forth, we often describe the regulatory requirements as the minimum requirement. That's just by virtue of the regulator is expected to only require what is necessary and sufficient for plant safety.

So it is appropriate to say these are the minimum requirements. We would hope that applicants would establish inspection and maintenance programs that go well beyond in terms of the scope and the practices. But that is not to say that we don't feel very strongly that we have put a lot of attention into the detail about making sure that we have what we need to make sure that these are effective aging management programs. So to that extent, it is an important baseline.

I think it's also important to point out that we have tried to avoid making this a catalog of options because that reduces the opportunity to standardize and achieve efficiencies by having one way to do it that everyone sort of gravitates to. So we did consciously try to avoid going well into what are all of the different ways that you can manage the aging effects, because that would then work against

the efficiency aspect of the guidance.

We certainly expected that we are going to have some departures from this, but we'll try to discourage that.

VICE CHAIRMAN BONACA: I understand. For example, on the issue of scoping, that you don't have in the presentation here, we discussed that before, NEI pointed out that all you need is to have a methodology and then the results of the whole process, including screening. When you do that, you really have a problem also with navigating through the application.

Now I expressed a concern we had last time. I believe that the ACRS probably will encourage more documentation to make it possible for an interested individual or the public to find out what components are in or out. It's not too much to ask.

Now I recognize in the SRP you had to recognize that that was the requirement of the rule, so you had to admit it. But you can see how that, in my judgement, is a minimum requirement for documentation. By meeting the minimum requirement, you meet the rule but maybe you don't fulfill the needs of the public and of the staff and the ACRS Subcommittee when they try to review these documents.

MR. GRIMES: Point well taken.

VICE CHAIRMAN BONACA: Okay. We can move on.

MR. DOZIER: Okay. I would like to turn it over to David Solorio -- Ed Kleeh, I'm sorry.

MR. KLEEH: Good morning. My name is Edward Kleeh. I am representing the License Renewal Branch. With me from the Office of NRR, the Division of Engineering are Mr. Barry Elliot, Mr. James Davis is coming up, Mr. Frank Grubelich, and from the Office of Research is Mr. Mike McNeil.

I will present the five NEI continued dialogue items by stating both the NEI and NRC position.

Item one is individual plant examination, IPE, or individual plant examination for external events, IPEEE, has a source document to consider for scoping. NEI considers it inappropriate for an applicant to establish a licensing renewal scoping and screening criteria that relies on plant-specific probabilistic analysis like IPE's and IPEEE's since they are not part of the current licensing basis. Not only reflect the estimated core damage frequency for the plant configuration at that time.

NEI contends that IPE's and IPEEE's may

contain recommendations to modify the plant, revise procedures, or develop training to further reduce the estimated core damage frequency, but only implemented after 10 CFR 50.59 or 10 CFR 50.90 reviews.

The standard review plan for license renewal, page 2.1-3, states that although the license renewal rule is deterministic, that probabilistic methods on a plant-specific basis may help access the relative importance of structures and components subject to an aging management review by drawing attention to specific vulnerabilities.

Reviewing an IPE or IPEEE can help a reviewer determine what equipment is risk significant and relied on for mitigation of design-basis events. It provides additional understanding to permit safety determinations.

VICE CHAIRMAN BONACA: Is this the NEI position still?

MR. KLEEH: No.

VICE CHAIRMAN BONACA: At which point did it become yours?

MR. KLEEH: When I got to the part about with the standard review plan, that was the NRC position.

MEMBER WALLIS: So the NEI position is

that some information should be ignored?

MR. KLEEH: Yes.

MR. GRIMES: This is Chris Grimes. Let me explain. This set of issues are issues for which we have two positions that appear to conflict, but we're not sure. So instead of appealing the issues, the NEI working group simply asked of the steering committee that the staff be available to continue the dialogue so that we can understand whether or not we have any disagreement. I think that it is fair to say that on the IPE issue, the industry's concern is more one of proximity, having the IPE described in a staff review that is supposed to be certifying the current licensing basis relative to the scope of equipment in an aging management review.

Their concern is that this device might be used in some way to subvert the current licensing basis.

CHAIRMAN APOSTOLAKIS: But I'm a bit confused though. The current rule is deterministic. It really looks at passive components. The IPEs have declared the passive components as being so reliable that they will not put them in the accident sequences.

So how is it relevant? If I look at the dominant sequences that an IPE gives me, that will

have valves not closing or opening and pumps and so on. How does that help me? I mean the deterministic rule says that I should be looking at the passive components. The others are already under the maintenance rule and so on, so it really doesn't help you very much. So I don't even know why it's a dialogue item.

MR. KLEEH: I have an inspection background. When you use IPEs and IPEEEs, they tend to give you a relative importance of what systems have a safety significance. You can classify and prioritize them. That's mainly what the NRC is trying to do here. They are trying to use all the tools available to be able to classify the safety significance of systems that they are going to consider to be scoped under the license renewal rule.

MR. GRIMES: The guidance instructs the reviewer to use EOPs, the IPE, and other information about the plant capabilities or lack of capabilities in order to have them use devices that help them to poke at the current licensing basis to determine the completeness of the scope.

IPEs are useful primarily because for those that still think in a systems paradigm they know what are the important functions of the system from an

IPE that they then go in and look for that intended function coming out of the scoping and screening.

So to the extent that it could be useful for the staff reviewers but the industry concern about there ought to be more guidance in how not to abuse it.

CHAIRMAN APOSTOLAKIS: So it's the next step we discussed this morning, beyond what Hatch did.

MR. GRIMES: Yes.

CHAIRMAN APOSTOLAKIS: But you still wouldn't look at the active components. Right? You would look at the systems, but then you would look only at what's passive. So there is progress. I'm telling you, in five years, there is going to be a PRA.

MR. GRIMES: I hope Dr. Bonaca doesn't expect that in our commitments for future improvements.

CHAIRMAN APOSTOLAKIS: NEI is concerned that this might subvert the process?

MR. GRIMES: By virtue of these being continued dialogue items, I think we need to offer NEI an opportunity to more clearly articulate what their real concern is. That's why instead of taking these issues to appeal at the conclusion of the last

steering committee meeting, the working group simply said we would like the staff to continue to talk with us. So we need to better understand what it is they want us to do differently.

CHAIRMAN APOSTOLAKIS: Now if the IPE, IPEEEs are used only to add things to scope, then I can see their concern. But if you use a risk-informed approach to define SSCs that are within scope, then it is a different story. They shouldn't really object to that. So I guess they are afraid that the first thing is going to happen, like the first 25 years of PRA, just add to the regulations but never take anything out.

MR. KLEEH: Item two.

MEMBER SHACK: I'm glad you made that point, George. It's one we haven't heard before.

MEMBER WALLIS: The thing that intrigued me was the first 25 years. When did the first 25 years start, George?

CHAIRMAN APOSTOLAKIS: I'm sorry?

MEMBER WALLIS: When did the first 25 years start?

CHAIRMAN APOSTOLAKIS: They are not biblical years.

Please go ahead.

MR. KLEEH: Item two. Operating experience with cracking of small board piping. NEI's position is that inserts inspections ISI and chemistry control are adequate as aging management programs. Operating experience does not justify doing more.

Now we get to the NRC position. GALL recommends a volumetric one-time inspection for evidence of no cracking to verify the effectiveness of chemistry control. The one-time inspection augments the aging management program consisting of primary water chemistry and in-service inspections for class I components.

The ASME Code, Chapter 11, requires service examinations of class I, small bore piping with less than a four-inch nominal diameter every ten years.

Are there any questions on that item?

MEMBER LEITCH: Does this issue only relate to class I small-bore piping?

MR. KLEEH: Yes.

MEMBER LEITCH: Thank you.

MEMBER SIEBER: And it doesn't relate to fatigue-induced cracking?

MR. KLEEH: It relates to all kinds of cracking.

MEMBER SIEBER: Not just chemistry?

MR. KLEEH: The cracking is the issue, not the chemistry.

Item three is management of loss of free-load of reactor vessel internals bolting using the lose parts monitoring system.

NEI believes that ISI visual examinations are adequate for management of loss of pre-load on reactor vessel internals bolting.

The NRC position is that GALL recommends that loss of pre-load in reactor vessels internal bolting be managed by ISI in the loose parts monitoring system. The NRC staff accepted Westinghouse Owners Group topical report WCAP 14-5-77 which recommends that the loose parts monitoring system as one of the surveillance techniques used to detect loss of pre-load and other aging effects on certain reactor vessel internals components as part of several aging management programs.

The ASME code, Section 11, category BN-3 requires visual inspections of core support structures every ten years.

Are there any questions on this item?

MEMBER WALLIS: How do you tell if the bolts are loose?

MR. KLEEH: How do you tell if the bolts are loose?

MEMBER WALLIS: By a visual inspection. Isn't that what you mean about loss of pre-load?

MR. KLEEH: That is what NEI is suggesting.

MEMBER WALLIS: How does visual inspection tell you if you've lost a pre-load?

MR. KLEEH: I don't think I am in a position to support their argument.

MR. GRUBELICH: Frank Grubelich, Mechanical Engineering Branch.

We have seen in the baffle bolt cracking experience where industry has said that they have not seen this cracking of the baffle bolts that was experienced over in Europe. However, we haven't seen it because what they were doing was a visual inspection. The crack occurs between the juncture of the bolt shank and the head.

Subsequently, the log took three lead plants, Westinghouse lead plants, and they did UT examinations. In fact, they found some cracking.

So our position really is to use loose parts monitoring. There has been experience with that, and that is a program that is an ASME standard.

It has been published.

MR. GRIMES: This is Chris Grimes. But I'll point out that there is an opportunity for regulatory coherence here because staff just approved a GE topical that concluded loose parts monitoring was not necessary.

MR. ELLIOT: Along that line, this is a PWR issue. In the boiling water reactors, we credit ISI and water chemistry for the bolting of the internals. This is only a PWR issue.

MR. GRUBELICH: Part of the discussion with the PWR is that the point that they were making is that the flows in the BWRs are relatively low so that they can't carry the loose parts, and that they also have limited or restricted flow passages so that the larger parts will not get into the core.

MEMBER WALLIS: I don't understand the connection. Maybe I should be quiet. If you have a loose bolt, it doesn't necessarily wander around. It has to come out to wander around.

MR. GRUBELICH: You can have both cases. It can be loose. It can stay in place.

MEMBER WALLIS: I'd think you would be concerned about it being loose and staying in place.

MR. GRUBELICH: Right.

MEMBER WALLIS: You won't catch that by seeing whether it was rattling around somewhere else.

MR. GRUBELICH: Correct. But you also worry about the part that gets loose and gets into the core area.

MR. MCNEIL: There's another difference between the Ps and the Bs. That is, that at the damage levels that are common in Bs, the radiation-induced creep is less severe, so you would have less loss of pre-load simply for the creep effect than you would in a P. I'm trying to explain the discrepancy between the position of the GE and the PWR system.

MEMBER SIEBER: But the baffle bolts are on the outside of the core barrel, right, or the baffle? So they either go to the bottom of the reactor vessel or into the steam generator head.

MR. GRUBELICH: There are two different baffle bolts. There's one on the inner surface, which is actually adjacent to the peripheral surface of the fuel -- then on the backside, there is what is called a core barrel former bolt. So you have both cases.

MEMBER SIEBER: Okay.

MR. KLEEH: Item number four is operating experience with cracking bolting. NEI's position is that crack initiation/growth due to stress corrosion

cracking through carbon steel closure bolting is not an aging mechanism.

Section 2 of the ASME code specifies the ASA 193 grade B bolting at minimum yields 105 pounds per square inch, and no maximum yield strength.

MR. MCNEIL: I think that figure of 105 pounds per square inch has to be wrong.

MEMBER WALLIS: 105 ksi. Must be thousands.

MR. KLEEH: That's what I said.

MR. MCNEIL: I'm sorry. I thought you said 105 pounds.

MR. KLEEH: If I did, it's supposed to be 105 thousands, and no maximum yield strength.

The minimum yield strength should be sufficient for normal design loads. The maximum yield strength preferred by the staff of 150 thousand pounds per square inch or less ensures the bolt is not too hard, meaning brittle, so as to be susceptible to stress corrosion cracking, which is more likely with moisture in the air and if the brittleness of the bolt increases.

GALL recommends that cracking issues/growth be managed by the EPRI bolting integrity program.

Are there any questions on this item?

MEMBER POWERS: I guess you were just a little too quick for me. The staff has come back and said that they don't want a high strength steel is because of the stress corrosion cracking limitations? And NEI is saying they are perfectly willing to let things stress corrosion cracks?

MR. KLEEH: I think what they are saying is they don't believe that stress corrosion cracking is going to occur. James Davis can elaborate on that.

MR. DAVIS: They just want to drop that out of GALL. They wanted to drop that issue out of GALL. We have a lot of evidence from the past operating experience that if your yield strength gets over 150 ksi, they will crack in air. As I said to the subcommittee, I'm not yielding on this point.

MEMBER POWERS: I guess I wouldn't either.

MEMBER SHACK: No pun intended.

MEMBER POWERS: You're not the only one that has the experience of cracking in the air on high-strength bolts.

VICE CHAIRMAN BONACA: Good. Fire protection.

MR. KLECH: The final item is inspection of fire protection systems. BI's position is that the

National Fire Protection Association, NFPA, codes are adequate for managing aging effects in fire water systems. The NFPA codes do not provide guidance for assessing internal corrosion of fire water systems which are not routinely subject to flow.

The NRC's position is that GALL recommends the single system monitoring, internal inspection and flow testing of fire water systems to ensure the corrosion including microbiologically effluence corrosion mix.

Are there any questions on this one? That concludes the presentation.

Mr. Dave Solorio will now take over.

MR. GRIMES: While Dave is moving up to the podium, I want to clarify. These were the -- this was the subset of industry comments on the improved renewal guidance that ended up being quote unresolved. They were originally characterized as potential appeal items, but when it came time for the industry to appeal the issues to higher management, they concluded that they did not want to hold up GALL to try and resolve these issues, rather they simply wanted the staff to continue a dialogue because perhaps we misunderstand their point or they misunderstand our point.

Barry pointed out this distinction about loose parts monitoring for PWRs and BWRs. On its face, has to be explained in a clearer way and perhaps they simply don't understand the staff's position.

But we will continue to have a dialogue and we'll report on what we learn in the future. And with that, David is going to address one-time inspections.

MR. SOLORIO: Good morning. My name is Dave Solorio. I work in the Office of Nuclear Reactor Regulation in the License Renewal and Standardization Branch.

I'm here today to speak on the subject of one-time inspections for Calvert, Oconee, Arkansas, Hatch and GALL.

With me here today is Omesh Chopra from Argon National Laboratories. Omesh is a Senior Member from the ONO team that assistant with the development of GALL and was the lead reviewer for many of the more difficult chapters in GALL.

I also have to my left here Robert Prato and to my right, Butch Burton, also from the License Renewal and Standardization Branch. Bob is the ANO Project Manager and Butch is the Hatch Project Manager.

I asked Bob and Butch to sit up here with me today because they worked so hard in getting me information to get ready for this. I thought that they should share in the glory also.

(Laughter.)

Last week, I made a presentation to the ACRS Subcommittee on license renewal regarding the one-time inspections for Calvert and Oconee and GALL. The subcommittee liked it and requested that we come back for this full committee to expand it to also cover Hatch and ANO.

I also have another slide after this, Slide No. 9 that summarizes the one-time inspections for Hatch and ANO. And also, I want to mention in case you're wondering what all the acronyms -- I haven't had a chance to turn to page 10. There's a definition. They have all the acronyms. I will note that I left off sodium hydroxide. I apologize for that.

I guess I want to provide some orientation here. First off, for those who might not have seen this before, the left column here are the categories of the systems as they'd be represented in GALL and the Standard Review Plan. I felt that a fairly efficient way to try to group things so that we could

try to draw some comparisons.

I also want to provide a disclaimer for anyone attending this briefing for the first time who are unfamiliar with the concept of one-time inspections. We're not saying these systems are only inspected one-time. In fact, in the majority of cases there's an existing Aging Management Program already looking at a lot of these systems.

I also wanted to mention that GALL has consistently applied the lessons learned of Calvert and Oconee regarding one-time inspections. In fact, as you've heard earlier, many of these one-time inspections from Calvert and Oconee were incorporated into GALL, when appropriate, as a starting point. In developing GALL, we had the experience of Argonne and Brookhaven National Laboratories helping us get this information into the GALL report and we also had staff members associated with the first license renewal reviews and the on-going reviews looking at the one-time inspections that were incorporated.

GALL also had the benefit of two public rounds of comments and an outcome of the public's participation as GALL now specifies a plant-specific Aging Management Program be proposed for Calvert and Oconee, might have proposed the one-time inspection.

A plant specific Aging Management Program could be a one-time inspection or it could be an on-going program, an existing program.

At a glance, you can see there's a few differences in the number of one-time inspections between Gall and the four plants --

VICE CHAIRMAN BONACA: Before you chance that, on the issue of the -- it would be valuable for us to understand why you have one-time inspection of pressurizer and one steam generator for Oconee, but there is no inspection for Calvert. Now I know Calvert has also steam generator inspections.

MR. SOLORIO: I will talk to that.

VICE CHAIRMAN BONACA: Also, why does the GALL report -- if you could give us some indication. I understand pretty much the same programs.

MR. SOLORIO: I will do that in a minute. All I was going to do was put this up briefly to kind of give everyone an orientation. There's some differences there. I'm going to go back to this and then I'm going to talk about what you wanted in a few more minutes here.

Actually, what I intended to do was go across for reactor vessel internals, all four plants, and kind of give you an idea of what they're doing and

I will cover that.

VICE CHAIRMAN BONACA: Okay.

MR. SOLORIO: So there's some differences. There's numerous reasons that explain those differences. I'm going to go over a few of those reasons and then I'm going to talk about -- get to your question, sir.

One reason there are differences is that GALL provides one method for managing the aging, that the staff has determined is acceptable. Applicants can and have proposed different Aging Management Programs different than GALL such as the case of ANO's risk-informed ISI inspection for small-bore piping or aging management for every piping. The staff has concluded that these are acceptable alternatives.

Another reason for differences is that there are plant-specific differences or system nomenclature differences. For example, Oconee has several features which are a little too unique, that we thought were a little too unique to be included in GALL. That would be some of these systems down here. They have a Cowamee Dam and it's our emergency power supply. I know a lot of you have seen it. I have heard some of you have been there. It was a little too generic to be included in GALL, so you won't see

a similar one-time inspection in GALL.

Also, Oconee doesn't have Oconee with one set of steam generators. Isn't going to have a steam generator blow down system, therefore, you're not going to see it. At Oconee, another example would be is that their fire protection system isn't labeled fire protection. It's actually two other systems. Low-pressure service water and high-pressure service water are used to provide fire protection function there. And so you look at that and you say where's fire protection for Oconee. Well, it's there. I could have labeled it as fire protection, but then I thought that perhaps someone would have asked me what about those systems? So I left it as it was.

Another reason was that in many cases Calvert and to a lesser degree Oconee proposed one-time inspections without being asked because of either plant-specific operating experience or because they wanted to ensure themselves of the effectiveness of their existing programs, or because they didn't suspect aging was occurring, but given the remote potential, they determined it was conservative to look up anyhow.

Another reason was that there were many

public comments, as you've heard earlier, received by the staff on GALL and the staff might have concluded that a one-time inspection was not necessary if an on-going Aging Management Program was considered to be adequately managed on aging.

I think last week we talked about changes to the ECCS, one-time inspection for PWRs because it was determined that if a licensee had a chemistry program that matched a GALL chemistry program, the conditions and the contaminant control and filtering should be sufficient to preclude the need for a one-time inspection.

Then I'm just going to get to two more examples and then I'll get to the question that was asked. In the case of Hatch, there's a really unique reason. There could be some differences here. It's because Hatch took a somewhat unique approach to how they scoped by function, not by system. And as a result several systems were grouped together in unusual ways, for example, one of the in-scope functions for the feedwater and main steam systems was reactor coolant pressure boundary. This function is identified under the nuclear boiler system such as here. I'll just leave that up.

The nuclear boiler system is lifted on the

first row here. Therefore, main feedwater and main steam are actually identified as part of the RCS function instead of the steam and power conversion function, so you won't see something down here for main steam and feed water at Hatch.

In the case of ANO, another reason you can -- you obviously see a number of differences there, but some of the reasons for why there are differences is that ANO is frequently doing periodic inspections, rather than one time inspections. Also, ANO proposed different types of Aging Management Programs such as the risk-informed ISI inspections for small-bore piping as I mentioned earlier.

VICE CHAIRMAN BONACA: So you are saying that those activities are captured under programs which already exist and are broader, so therefore you don't have to have a one-time inspection for that specific result. That really accounts for the big difference in numbers of one-time inspections you show there?

MR. SOLORIO: Yes sir.

VICE CHAIRMAN BONACA: "SH" stands for what?

MR. SOLORIO: Pardon me?

VICE CHAIRMAN BONACA: "SH" under

Arkansas.

MR. SOLORIO: Sodium hydroxide.

VICE CHAIRMAN BONACA: Okay.

MR. SOLORIO: It's our containment. It's also my understanding that that subject of one-time inspections for ANO was previously brought up during the subcommittee meeting, so you may already have appreciation for some of the differences of ANO.

Now I'd like to go over a few examples to explain the transparencies in a little more detail.

MEMBER POWERS: Let me ask one question. If a licensee has a super water chemistry program, I mean it's a humdinger, it really cleans the water up well, does that preclude the need to do a one-time inspection?

MR. SOLORIO: Well, if the reviewer was going to use GALL, GALL would tell the reviewer that if the chemistry program is equivalent to the GALL chemistry program, there may not be a need unless there's some specific plant operating experience which might suggest otherwise.

MEMBER POWERS: The reason I worry about that is I guess there's some evidence that maybe as we clean water up we unleash new corrosion mechanisms because the impurities that are causing are not being

tied by complexing or being captured by some of the impurities in the water and so clean-up, good chemistry does not necessarily mean you don't have corrosion.

MR. SOLORIO: Yes, although in a situation as that, perhaps there might be operating experience at that plant that would suggest that their chemistry program, even though it sounds like a whammo-bammo one isn't perfect and there might be a good reason -- and you would expect an applicant to describe that in the application.

MEMBER POWERS: Yes.

VICE CHAIRMAN BONACA: I'd like to ask a question about Arkansas. I mean the one-time inspections are confirmatory in nature, typically. I mean you are doing it once to verify that, in fact, an aging effect is not taking place, okay, that's confirmatory. A program is to address the possible aging effect that you believe is going to happen, so you have a programmatic inspection that you do.

So if I look at Arkansas, for example, they believe, evidently that some aging may occur of the components that other applications say they're not going to happen and so they only have one-time inspection and Arkansas has programs to inspect many

times. Have you thought about that?

Let's take an example of small-bore piping. The other applicants are saying there's no aging effect coming from it, therefore, we're going to look at it once and then forget about it. Arkansas says no, we're going to have it under a program. We're inspecting under ISI. So they must believe that that's necessary.

Can you comment on that? I mean --

MR. ELLIOT: Arkansas took a little bit of a unique approach where when they first initiated their Aging Management Review they identified the components and the environments and then they identified all of the maintenance activities that they do on all the programs that are in place. A specific program addresses specific aging effect as to whether or not it's not likely to happen. They still took credit for that program, where I think some of the other applicants may not have done that. They may have said that this is not a practical aging effect, there's no need for us to commit to doing anything, therefore, we'll do a one-time inspection to verify that it is not happening.

VICE CHAIRMAN BONACA: So that you don't want to place their commitment on the ISI for --

MR. ELLIOT: Yes. It shouldn't be taken as a recognition that they need to do it. It's just the fact that they feel that they had a program in place. There's no harm for them to take credit for it and instead of going through an exercise with the staff on arguing whether or not it's likely to happen, they decided that they would leave it in and commit to it.

MR. GRIMES: Dr. Bonaca, I think it's also important to recognize with risk-informed in-service inspection there were benefits that were provided by risk-informing the scope, concluded that there were some things they had been inspecting and do not now need to inspect. And so when you say that Arkansas felt that they needed to do this, Arkansas felt that they needed to have a risk-informed in-service inspection program and so it does have the advantage of picking up small-bore piping, but at the same time it was compensated for it by reducing inspections in other areas.

MR. SOLORIO: Going to page 8, first row for reactor vessel internals, reactor coolant system. For small-bore piping, Calvert and Oconee plan to conduct a one-time inspection. GALL calls for a one-time inspection. On page 9, you'll see that ANO isn't

there, but that's because they're doing a periodic inspection, so they are still looking at small-bore piping.

For Hatch, small-bore piping inspections are the subject of an open item. There is still continued dialogue on that one so I guess you can ask Butch in a few more months how that ended up.

Moving on to reactor vessel internals. Calvert has a one-time inspection for CEA shroud bolts. Oconee does not have a one-time inspection for similar functioning type of bolts at Oconee because of a different material. There's not the same concern. GALL calls out for a plant-specific evaluation for reactor vessel internal bolts of this nature.

ANO has committed to a one-time inspection of reactor vessel internals that includes bolts, baffle bolts. Hatch covers aging management of reactor vessel internals in accordance with BWRVIP program. I understand that that's been reviewed and if you want to ask more questions, that's part of the reason I've put you up here, to help with that. So generally, you can see how the subject of bolting isi being covered there.

Moving on to steam generators, Calvert has a comprehensive program that includes inspections of

steam generator tube supports at the U-bend area. Oconee has a different design, but still has a one-time inspection for some supports due to gamma radiation concerns that they have. GALL recalls a plant-specific evaluation. ANO supports -- ANO has existing programs that cover and support inspections and of course, Hatch doesn't have steam generators, so it's not applicable.

Moving on to the pressurizer. Calvert and Oconee have committed to conduct a one-time inspection of susceptible cladding locations. GALL requires a plant-specific evaluation. ANO has committed to conduct periodic pressurizer examinations, polymetric examinations. It's my understanding also that ANO and Oconee are planning to perform one-time inspection of their pressurizer heaters in conjunction with a BNW Owners Group program or initiative. Of course, again, Hatch doesn't have a pressurizer.

Those are the examples I was going to go over just because of time, we're running late. Of course, you can ask questions.

MEMBER WALLIS: There doesn't seem to be much correlation between the entries from the various plants on the GALL Report.

MR. SOLORIO: Well, I mean I really would

have to take --

MEMBER WALLIS: I don't think we could possibly go into them all. There just doesn't seem to be that much correlation. I wondered if there was some general conclusion you can draw from those.

MR. SOLORIO: I was going to -- look at aux systems. CC is component cooling. That's actually covered by the CCCS in GALL.

Service water and salt water, Calvert. Service water at Oconee. That is an open cycle.

MEMBER WALLIS: It's just given another name in GALL?

MR. SOLORIO: Yes.

MEMBER WALLIS: Okay.

MR. SOLORIO: I'm sorry. Fire protection here is equal to LPSW and HPSW there. It's equal to fire protection here.

MEMBER WALLIS: So it's just a translation problem.

MR. SOLORIO: That was a big problem trying to correlate things between the units, especially with Oconee for me, anyway.

MEMBER WALLIS: It looks like a real conspiracy against the laity.

(Laughter.)

MR. SOLORIO: I would just like to conclude my remarks by saying that GALL has consistently applied the lessons learned of Calvert and Oconee and also to a large degree at ANO because the GALL reviewers were also working with ANO too to cover the one-time inspection subject. While there are some differences, I hope I was successful in explaining that they're due to plant-specific nature, nomenclature, design, periodic versus one time. So that's how I would conclude this part of the presentation.

I have one more slide to discuss.

(Slide change.)

Transparency, page 11, here, provides a conclusion for our presentation. We hope that we've impressed upon you a lot of work has been done and while there could be more work done to address the five continued dialogue issues, we believe that these documents should be provided as final so that future applicants and the staff can benefit from the stability and efficiency they'll provide. Therefore, we request your endorsement for issuing the final documents to begin their implementation.

MEMBER LEITCH: Would the -- on the five issues that we talked about earlier, would the final

documents be issued with being silent on those areas or with the NRC position on those areas? Is there yet hope of resolving those issues prior to the issuance of the final document?

MR. GRIMES: We would expect to issue the final documents with the NRC position on those issues. We've agreed that we can continue to discuss them, but we've taken a position that we're prepared to defend in terms of what's necessary and sufficient and even though the industry would like to continue the dialogue, we're only going to defend the position that we're putting forth in the guidance right ow.

MEMBER LEITCH: And then I suppose from reading the preamble of the GALL that if industry, if on a plant-specific basis they want to take exception to that, they can always do that and argue that on a case by case basis.

MR. GRIMES: That's correct. And that's consistent with any regulatory guidance. Applicants can always propose to depart from the guidance or depart from standards and justify it on a plant-specific basis.

MEMBER SIEBER: It sort of seems to me that there's a lot of flexibility in the Standard Review Plan and GALL and so forth and when I review

from my location, the plant application and compare them with all the regulatory guidance that's out there, particularly in scoping where some is done by function, other plants do it by system, it's very difficult and it just seems to me that it's difficult to navigate through all this and fully understand what is going on without access to the FSAR and plant drawings and in some cases system descriptions, so my impression is that this is not all that transparent from the standpoint of public analysis and public consumption.

Do you agree with that, Dr. Bonaca?

VICE CHAIRMAN BONACA: Yes.

MEMBER SIEBER: In other words, I had difficulty going through all this and understanding what fit into what boxes and what plant called what system or what function by what initials and it's just hard to do, it really is.

MR. GRIMES: And I would like to emphasize we've recognized that and as a matter of fact, I think the illustration of the language barriers that we continue to face, that Dave described in the one-time inspection area clearly indicates that there are things that we could do to improve the transparency of the process.

But we've been working on this explanation since before the draft Standard Review Plan was issued for trial use in 1997 and so while there are a lot of things that we could do to improve the clarity and understanding and communication between the interested parties, the working affected in interested parties or WAIPs as I like to refer to them, we think that the substantial -- excuse me, I think that the substance that we've accomplished in cataloging what's really important to a decision about the effectiveness of Aging Management Programs and guidance to the reviewers on how to wind their way through the various current licensing bases and different plant nomenclatures, we think that we've captured a lot of that and even though there is still navigational difficulties, that gets me to the response to Dr. Bonaca's original request and that is I fully expect to incorporate another round of lessons learned some time after the demonstration project.

I'm still not clear in my mind what that time frame is, probably less than a year after the original issuance. So we don't have time line or frequency clearly established. I think that the summer will give us some idea about how soon we might see the first update to this guidance.

I also don't know at this point whether or not we're talking about achieving so much transparency with the original demonstration that we totally reissue the guidance in plain language, or whether or not we're going to continue to nibble away at it and simply issue supplements to the GALL, SRP and regulatory guide until such time as we really make substantial improvements and the NRC's ability to speak in plain language.

The major lesson at this point that I think that we've learned since the original attempts to figure out how to draw a license renewal conclusion, almost exactly a decade ago, with the 1991 rule and I'd say at this point that yes, there's still a lot more that we can do, but there's so much that we've accomplished that we would like the ACRS to endorse the promulgation of this guidance in final form so that we can start now working on tweaking it to make it better.

MEMBER LEITCH: By this guidance, we mean not only the GALL report, the Standard Review Plan, but also the Reg. Guide?

MR. GRIMES: And its endorsement of NEI Guide 95-10, Revision 3.

MEMBER LEITCH: Are the differences

between the Reg. Guide and 95-10, Rev. 3 resolved or is there still some --

MR. GRIMES: There were no differences. The Reg. Guide proposes to endorse 95-10, Revision 3 without exception.

MEMBER LEITCH: Okay.

MR. GRIMES: There isi guidance in the Regulatory Guide that gets to some administrative details about electronic filing and packaging and so forth, but the Regulatory Guide does not take exception to the NEI Guide and we have verified that Revision 3 incorporates the substantive changes associated with the Standard Review Plan so that those two guides are not going to obviously conflict with each other.

MEMBER LEITCH: Okay. One other thing I'd like to comment on is we haven't talked to anything about the format of the GALL, but I think this format is far superior to what we saw four months ago. I don't know who's responsible for revising it, but it's much more user friendly than -- to me at least, than the two-page spread out thing. It's a lot easier to review.

VICE CHAIRMAN BONACA: With that, are there any more comments or questions for the

presenters? For Mr. Grimes? If none, I'll give it back to you, Mr. Chairman.

CHAIRMAN APOSTOLAKIS: Thank you, Dr. Bonaca. Thank you, gentlemen.

We have the first session of the afternoon, Safety Issues Associated with the Use of Mixed Oxide and High Burnup Fuels. There will not be a presentation by the staff. The subcommittee chairman will brief us for about 20 to 30 minutes. So what I propose we should do is start our discussions after the briefing of the Commission meeting in May, okay? We will not need a transcription. Would you please come back at 2:50 because we still have a session that needs to be transcribed.

And with that, we'll reconvene at 1:10.

(Whereupon, at 12:10 p.m., the meeting was recessed, to reconvene at 2:50 p.m., Thursday, April 5, 2001.)

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

(2:50 p.m.)

VICE CHAIRMAN BONACA: We lost our chairman, therefore we --

MEMBER SHACK: That's why we have a vice chairman.

VICE CHAIRMAN BONACA: That's correct. So I am starting the meeting again and next presentation that we have right now is the Thermal Hydraulic Issue Associated With the AP1000 Passive Plant Design and I believe that Dr. Wallis is leading this discussion.

Dr. Wallis?

MEMBER WALLIS: Thank you very much.

MEMBER POWERS: Will it touch on the momentum equation?

MEMBER WALLIS: I guess we can ask questions about anything we choose to ask about.

The subcommittee met with Westinghouse and spent about three times as long as we're going to spend today, but the purpose was really a preliminary presentation by Westinghouse to let us know what AP1000 is, how they approached its design and how they're approaching their application for licensing. They view this as an informational meeting and they do not expect us to write a letter at this time.

I would point out that the staff has yet to begin their review of AP1000. So it's a big premature for us to reach some conclusions without some input from the staff.

Without more delay, I'd like to invite Westinghouse to proceed.

MR. WILSON: Good afternoon. I'm Jerry Wilson. I'll begin the meeting. I'm with the NRC's Future Licensing Organization and I thought I'd start out with a little bit of overview on the AP1000 review.

Last year, Westinghouse approached us and said they were thinking about seeking design certification for their AP1000 design, but before doing that they wanted to determine what the scope and cost of that effort would be and more specifically, to get agreement on --

MEMBER WALLIS: Someone has changed the -- I'm sorry, Jerry. Someone has changed -- I introduced you falsely. Someone changed the agenda on me. I'm sorry.

MR. WILSON: That's all right, Dr. Wallis.

MEMBER WALLIS: Maybe you should correct the record.

MR. WILSON: No one would accuse me of

being a representative of Westinghouse.

MEMBER WALLIS: Maybe you should tell the record who you really are.

MR. WILSON: As I said, I'm Jerry Wilson and I'm with the NRC staff in the Future Licensing Organization.

Westinghouse had specific issues that they wanted agreement on to determine -- that would affect the scope and duration of a review for design certification and so we set up a three-phased approach to do this. The first phase was to determine the issues we should look at for the pre-application review and estimate the effort to do that. We completed Phase 1 last July. Met with the ACRS in August. Got a letter from the ACRS. And also in August of last year, Westinghouse decided to proceed with Phase 2.

Now in Phase 2, Westinghouse requested that we evaluate these four issues. Is the test program that was performed for AP600 sufficient to support the AP1000 application? They've submitted two reports as you see here on the overhead. We're in the process of getting ready to start that review. NRR is going to be the lead in this review and we're seeking assistance from Office of Research.

The next issue is applicability of the AP600 analysis codes to the AP1000 design review. Westinghouse has yet to submit the code applicability report to us. We see this as a key part of our review and that's the part that will make our assessment when we officially start the review and so we're waiting to get that information.

They also are seeking additional use of design acceptance criteria beyond what was done in AP600. They made a submittal on that area and the staff has begun its review in that regard.

Finally, we have to look at the exemptions that were granted on AP600 to see if they would still be granted on an AP1000 review.

Now we've estimated that it's going to take approximately 9 months to do this review. Although we haven't officially started the review, I would for planning purposes tell the committee that I anticipate in approximately 6 months we'll be back with our recommendations on the Phase 2 results. We'd like a letter from the committee at that time. We'll also be preparing a letter, a SECY paper to the Commission, advising them of our recommendations on Phase 2 and once we hear from the Commission on that, then we plan to send a letter to Westinghouse, giving

them NRC positions.

And Mr. Chairman, that's all I had for this overview. If there's any questions I can take them now.

If not, then I'll turn the meeting over to Mr. Corletti of Westinghouse.

MEMBER WALLIS: Thank you very much.

MR. CORLETTI: Thank you. Good afternoon. My name is Mike Corletti. I'm with Westinghouse Electric Company. Thank you for having us today.

(Slide change.)

MR. CORLETTI: Our agenda, we're going to be speaking, you see here, I'm going to be talking about really our purpose for this pre-certification review and give you an integral NSSS overview, overview of the NSSS. Then Terry Schulz will be talking about our passive safety systems design and analysis. He'll be focusing on the plant description and analysis report that we submitted in December, that included a description of the AP1000 and preliminary safety analyses that were performed, using the codes that were developed and approved for AP600.

Bill Brown will then be discussing our PIRT and Scaling Report that we submitted last month.

We really see that as the first key deliverable for the codes and testing issue because before we can get to the detailed review of the code, we really have to come to agreement that the tests that were used to validate the codes for AP600 are also applicable to the AP1000. And that report provides scaling to -- our scaling approach is outlined in that report. I believe you've all received that.

Finally, Mr. Gresham will get up and speak with regards to our planned approach for codes. Our plan is to the use the codes that were approved for AP600 and we owe a code applicability report that is due out mid-month and Mr. Gresham will speak to that.

Finally, the other issue is that of design acceptance criteria and Richard Orr will speak about our approach for design acceptance criteria and also talk a little bit about some seismic analysis that had been completed already for AP1000.

(Slide change.)

MR. CORLETTI: As Dr. Wallis said, this meeting is basically an informational meeting. It was not our intent to ask for a letter at this time and really to introduce ACRS to AP1000 design, how we've gone about designing the plant based on AP600. The objectives of the pre-cert review, I believe Jerry's

covered those already and then our proposed approach resolving these issues.

(Slide change.)

MR. CORLETTI: We came to the staff last year about around this time talking about the AP1000. We had worked on it for some time since we had completed AP600. When we completed AP600 in the commercialization of that, the market has changed significantly from the time that AP600 was initiated and this is what is driving towards developing the AP1000. Basically with the approach of using the AP600 as a basis, we can use the design, the detail design that we developed on AP600 and really, we're developing the AP1000 within what we're calling the space constraints of the AP600.

(Slide change.)

MR. CORLETTI: You'll see here -- no you won't. When we say the space constraints of the AP600, you see here's the AP600 and AP1000 side by side. So if you look at a plan view, the plants are essentially the same, the same structurals generally. The steam generators are somewhat larger to account for the higher core power. But really, from this view it looks, it basically is the same view.

(Slide change.)

MR. CORLETTI: When you look at the section view, the containment has grown to accommodate both steam generator removal and the larger mass energy releases associated with the larger core power.

(Slide change.)

MR. CORLETTI: On the AP600 or AP1000, basically we're also trying to use the same components as much as possible, use proven components that have been used at Westinghouse plants and others. By using this approach, we retain the basis for the cost estimate, the number of components are the same, the same configuration essentially. Some of the capacities are increased, but the number of components and the way they're all put together are essentially the same.

With our approach we're also -- the key to this is for AP1000, is to meet the regulatory requirements that we encounter for the passive plant, so really, we're adopting all the passive plant issues and also part of that is preserving the large safety margins that the passive plant had with AP600 and in our reports that we've sent in today, or up to this date, have tried to demonstrate that with a preliminary safety analysis that we've shown to illustrate the large safety margins that we're

preserving with AP1000.

MEMBER WALLIS: So 1000 was just chosen as a nice round number, rather than some optimum and why isn't it 1200 or 1500?

(Slide change.)

MR. CORLETTI: Well, basically, the next slide here, next two slides, we wanted to stick with a proven core design and so we went to -- for AP1000 we went to a 14-foot core, longer fuel assemblies. We have 14-foot cores in our South Texas designs and also in Doel and Tihange, two plants that are in Belgium. And those plants, actually have 157 fuel assemblies which are the same as AP1000 so the core design is essentially the same. Now those plants, the Belgium plants are at 3000 megawatts thermal. AP1000 has been, the core power has been increased to the same level from a power density as our operating three loop plants.

So that was what basically sized -- we didn't want to make the vessel bigger in diameter. We made the vessel longer to accommodate the longer fuel assemblies, but we didn't want to make it, to grow in diameter, because that would have affected the structures.

MEMBER WALLIS: Not longer than South

Texas?

MR. CORLETTI: Not longer than South Texas. We wanted to keep within an experienced basis that we had with South Texas.

(Slide change.)

MR. CORLETTI: You see some of the key comparisons of the 600 and 1000. As I said, the reactor power is increased from 933 megawatts up to 3400 megawatts thermal. The hot leg temperature has been increased from 600 to 615, but that again is within our operating experience.

The number of fuel assemblies is increased. Also the number of control rods is increased from 45 to 53. The reactor vessel ID is the same. It's the same ID, again, it's grown in length.

The steam generator, the steam generator surface area has been increased to 125,000 square feet. It just so happens that as we begin the AP1000, our steam generator design group had just completed design and actually has set the steam generators to the Arkansas units which were a generator of about 1500 megawatts per generator, about this size. We based the design largely on that design. Since then, we've merged with Combustion Engineering which has more experience with designing steam generators at

this power level. The team has been working together to finalize the design of the AP1000 steam generator.

Essentially, we'll have the same performance requirements with the low moisture carryover of the delta 75 that we had on the AP600, Iconel 690 thermally-treated tubes.

MEMBER LEITCH: Are there any AP600s actually under construction now?

MR. CORLETTI: No sir.

MEMBER LEITCH: So your plans for the AP1000 don't depend upon building any AP600s, necessarily?

MR. CORLETTI: That's right. We're still basing it on proven components. We're not relying on this to be a follow-on to AP600. It would be available, essentially if a customer wanted to purchase a plant, we believe we can the schedule that we could do almost either one within the same time frame.

MEMBER LEITCH: Okay, thanks.

MEMBER POWERS: Why the 690 alloy for the steam generator?

MR. CORLETTI: That is what we've been using on their most recent steam generators.

MEMBER POWERS: That does not speak highly

for it. I mean it's not immune to stress corrosion cracking.

Why not go with the 800 alloy?

MR. CORLETTI: I believe that the operating experience with the 600 has been very good, 690. And they basically have not seen the need to change. They've had very low incidents of any tube plugging with this material. It has excellent operating experience.

MEMBER SIEBER: Do you have any Iconel 600 anywhere in the reactor coolant system pressure boundary?

For example, it's extensively used in current PWRs on the head, some weld filler materials, etcetera, pressurizer.

MR. CORLETTI: No. I cant speak to -- I can't speak to that. We've been using the approved materials that we used on the AP600 which more the Iconel 690 and I know the materials that they selected were basically in accordance with the latest EPRI guidelines on materials selection.

MEMBER SIEBER: On the other hand, your Tihange temperatures went up by 15 degrees which puts it into the sensitivity zone, so the operating conditions are different than the AP600. I'm just

wondering if you made a change to materials in any way to account for that?

MR. CORLETTI: No. It will be the same as AP600.

MEMBER SIEBER: Okay. You also state that the reactor vessel diameter is the same?

MR. CORLETTI: Yes sir.

MEMBER SIEBER: But there is 12 extra fuel assemblies in there? How do you accomplish that?

MR. CORLETTI: I don't have that, but basically on the outer periphery, at the north, southeast and west of the core, there was room for three additional assemblies. It's essentially the same as our three loop plants now that have 157 assemblies. They were eliminated on AP600.

MEMBER SIEBER: Okay. So that should improve the neutronics efficiency a little bit as opposed to making a 14-foot core reduces your neutronics efficiency? Does that come out as a sort of a fuel cost balance or do you know?

MR. CORLETTI: I don't know.

MEMBER SIEBER: Thanks.

MEMBER WALLIS: Well, the power rating per area of fuel is higher?

MR. CORLETTI: Yes, it is. AP600 had a

very lower power density core. You see it's 4.1 kilowatts per foot. We've increased it up to the level that we have in our operating three loop plants.

MEMBER WALLIS: That's the main way in which you get the extra power?

MR. CORLETTI: Yes sir. And increasing the length. One of the consequences to go to the higher power, we had to increase the capacity of the reactor coolant pump. The reactor coolant pump is increased from 51,000 gpm to 75,000 gpm flow rate and the head is increased from 240 feet to 350 feet of head.

In order to minimize the impact to the motor, we've gone to a variable speed controller. That's only used during shutdown. When you start the pumps up in cold water, that is the largest draw on the motor and that's typically what the reactor coolant pumps, Westinghouse's reactor coolant pumps are sized for. With the variable speed controller it allows you to start the pumps at low speed in the cold conditions. When the fluid is heated up to operating conditions, then that is disengaged.

MEMBER SIEBER: Is that an electronic controller?

MR. CORLETTI: Yes.

MEMBER LEITCH: Mike, you said used during shut down. Do you mean start up?

MR. CORLETTI: Right. That's right. Shut down operations is anything called low temperature.

And then again, the pressurizer has been increased with respect to the AP600.

MEMBER SIEBER: Do you expect that the higher flow rates you have at the additional steam generator tube vibration or fuel vibration?

MR. CORLETTI: The fuel vibration you have to look at the upper guide supports.

MEMBER SIEBER: Right.

MR. CORLETTI: Because the one that's right in front of the hot leg is the most and we have looked at that and we've looked at where we were on AP600 and we do have sufficient margin, but that is the most susceptible.

On the steam generator tubes, we've increased the number of tubes, so that the velocities through the tubes is not appreciably larger.

MEMBER SIEBER: Thank you.

MEMBER LEITCH: Mike, to go back to the question of hot leg temperature. I noticed that South Texas has a hot leg operating temperature of 624 with Iconel 690. That's apparently a fairly new steam

generator, is that --

MR. CORLETTI: Yes. We just replaced that steam generator.

MEMBER LEITCH: I was wondering, is that design temperature or --

MR. CORLETTI: That's the operating temperature. And the units at Doel and Tihange are at very high hot leg temperatures also. There's many units, I think you see in the table there that have operating temperatures.

DR. ROSEN: The South Texas Unit 1 steam generators have been replaced. The Unit 2s have not yet been replaced. They'll be replaced in 2002.

MEMBER WALLIS: Any other questions for Mr Corletti?

MR. CORLETTI: Thank you. The next presentation is on the passive safety systems and Terry Schulz is going to present that and basically our design approach to designing the AP1000.

Thank you.

MR. SCHULZ: Good afternoon. My name is Terry Schulz and I will be talking about the passive safety systems and our design approach to those systems and try to give you some insights into how we have come to the sizes and capacities that we've

selected.

(Slide change.)

MR. SCHULZ: First of all, the approach is to use the same configuration, as Mike pointed out, as AP600, same arrangement. However, in the passive systems we know we have to increase the capacities in some areas and we've selectively looked at where we think we need to do that to maintain adequate safety margins.

We've considered both deterministic and PRA conditions and we've also given consideration for applying margin, as we did in AP600 to where there was test or computer code uncertainties.

The process we used is an iterative process and we've actually done this a couple of times already, where we looked at basically a hand calculation type, sizing, estimating of the performance using first principle type hand calculations which are largely independent of test and analysis.

These calculations are typically not a transient, but a point in time that we select based on our experience and understanding of the plant. Then we kind of check that and verify it using the computer codes, again, at this point in time AP600 computer

codes, the same ones we used in the SSAR analysis. These are not intended or portrayed to be Chapter 15 final analysis. They're kind of check calculations. They're obviously able to look at the transients, the integrated effects of the plant response. We've not done all the events we would eventually do in a SSAR, but we've looked at what we consider limiting events.

And another factor that does affect our, in some cases what we chose to do, was constraints in the plant. As Mike pointed out, physical constraints in the plant can affect the design, the design approach that we have.

MEMBER WALLIS: Did your thermal draw code analysis lead to significant changes in the design or did the eventual thing look just like what you had in your hand calculations?

MR. SCHULZ: Well, for example, in the passive RHR, our initial idea was to increase the pipe size and not to change the heat exchanger because that was minimizing the change to the plant and we thought we had -- and that would give us maybe a 25 percent increase in capacity, heat removal capacity which is not nearly as much as the power increase, but we thought we could compensate for that by having much more mass in the steam generator. And for some

events, in fact, that was adequate.

However, for other events like a steam generator tube rupture, it didn't work as well as we wanted it to, so we introduced another change, was to increase the capacity of the heat exchanger. So in fact, there are cases where -- when we went through the computer analysis, we learned things that we didn't have in hand calculations and in some cases it was just other events that we hadn't considered when we did the hand calculations. In other cases, the hand calculations are, of course, very simple, relative to the computer and not as accurate.

MEMBER WALLIS: Well, yes, okay.

(Slide change.)

MR. SCHULZ: The first feature I would like to talk about is the passive RHR and the configuration of this heat exchanger and system is exactly the same as AP600 in terms of valves, the arrangement of the pipe of the heat exchanger, the elevations, in fact, are the same. We did increase the pipe size from 10 inch to 14 inch and we increased the surface area by adding longer horizontal tubes and a few more tubes. I think the heat exchanger surface area increased about 22 percent.

(Slide change.)

MR. SCHULZ: We did some hand calculations on both the AP600 and AP1000 which -- and this hand calculation is actually fairly sophisticated in this case and using the same correlations we use in our computer codes. It's to calculate the heat transfer in the AP1000. It is almost as much as the power increase with the changes of both the pipe size and the surface area. Not quite, and you see the time to match decay heat is a little bit longer. If you also consider what's going on in the secondary side of the plant, Mike Corletti pointed out we have these larger steam generators.

We've also applied more water mass on the secondary side per megawatt than AP600. So at the beginning of a transient, we've got like 36 percent more water per megawatt. At the end of the transient when we've boiled off some of that water, we have almost twice as much water. So even though our heat exchanger is a little bit smaller, the net effect of having more mass in the steam generator means that we've got even more margin relative to heat removal capabilities.

So from this point of view in terms of say a hand calculation, we expect the plant to have increased margins.

(Slide change.)

MR. SCHULZ: In addition, we have done a number of transient analyses. I'll show you the feed line rupture. We also looked at loss of feedwater in steam generator tube rupture. It's a little hard to tell which plant is which here, but you can see this is plotting the saturation pressure versus the -- on the high side there and the hot leg and cold leg temperatures down below. And the general trends are similar. The AP1000 temperatures are a little bit higher, so the subcooling margin is slightly less, but it is still very significant, 140 degrees at least in AP1000.

Current operating plants, this temperature tends to go back up and come within a few degrees of saturation, not that that is an unacceptable situation, but it's a measure of safety that we use in this type of a transient. So our conclusion here is that AP1000 behaves very much like AP600 in terms of a transient response.

(Slide change.)

MR. SCHULZ: The next thing I'd like to move on to is to talk about the passive safety injection features. And this includes the accumulators, the core makeup tanks, the ACS system

and the IRWST and recirculation.

Again, the configuration, if you look at this same sketch for AP600, they look exactly the same. A number of valves, the way the valves are connected is exactly the same. The elevations are almost the same except for the pressurizer is a little taller, so some of those valves are up a little higher.

The core make up tank has been increased in size about 25 percent and the flow capability has been adjusted by adjusting a flow tuning orifice so that the flow is also 25 percent more. So we're getting a bit more core makeup tank flow. Accumulator capability has not been changed and I'll speak to that in just a minute. Fueling water storage tank, the injection lines, the containment recirculation lines and the ADS stage 4 pipes have all been made bigger to make, to increase the capability of IRWST injection and recirculation. I'll talk about each of these in turn.

(Slide change.)

MR. SCHULZ: At the time I have this up I want to also have this slide up here so I can -- so I have on the left slide here, a margins assessment, again a hand calculation type thing, for each of the

key features, the accumulator, for example, core make up tank and so on, where we've tried to get a measure of how AP600 and AP1000 compare.

For the accumulator, we did a kind of ratio on power density and time to refill the core and ratio to peak clad temperature. So this is not a sophisticated, large LOCA analysis. It's a simple ratio of the fact that AP1000 has the higher power density. We expect the core to heat up faster in the reflood stage. And so we think that the peak clad temperature might be something around 1940 degrees as opposed to 1640 for -- and these are basically -- the AP600 number is the best estimate LOCA with uncertainty as quantified in the SSAR for AP600.

And as I mentioned the flow capability of the accumulator was not changed. And the tank itself is constrained by concrete walls on the sides and the floor. It's already a spherical shape so it would have been pretty challenging to make that tank bigger.

The other factor is that there are a number of operating plants that have large LOCA peak clad temperatures that are as high and higher than the 1900 and of course, the licensing limit is 2200. So we feel comfortable with that result.

The core makeup tank, I mentioned we

increased it by 25 percent both in flow and volume. What you see here is a comparison of the flow capability of the core makeup tank as opposed to a calculated requirement at the point in time when the accumulator would empty in a direct vessel injection line break.

This is, in our experience, the most limiting condition for core makeup tank because in a direct vessel injection line break, one of the tanks spills, the other one injects and so it has to perform the whole duty. And you see here the margin of the design versus this requirement is a little bit less on AP1000, but it still looks comfortable in this situation.

ADS stages 1, 2 and 3 we have not changed for the AP1000. It's exactly the same, pipe sizes and valve sizes. And we think that that is adequate for AP1000 because at the higher pressures that this system is important at in terms of the initial depressurization, we can get adequate flow. So even though the AP1000 has more power and a bigger reactor coolant system volume, that this system will perform adequately and in our computer analysis shows that.

On the other hand at ADS stage 4, we've significantly increased the capacity. I mentioned the

pipe sizes go up from 10 inches to 14 inch for each of the ADS stage 4 lines and there's four of those. And if you look at with the same delta P across the system, the flow would go up about 89 percent versus AP600. That's, of course, not saying it's enough, but it's giving you a feeling for how much flow capability we've added to the system.

Now the ADS stage 4 works very closely with IRWST injection and later on, containment recirculation. Both of those, we've also increased substantially by making the pipe sizes bigger and in the case of containment recirculation, we've done one other thing which is to change the alignment of the normal RHR system.

The normal RHR system is not a safety system. It doesn't have to work, but it is suggested in our emergency procedures that the operator should turn it on because it adds a level of defense. It also, in the case of a direct vessel injection line break, would tend to increase the rate at which the IRWST drains down because it's going to spill more flow if it's running than if it's not running.

This is all accounted for in AP600, but in AP1000 we changed the normal water supply from the IRWST which is inside containment, to another supply

outside containment. So if the pump works, it will actually make things better instead of making things a little worse. And that gave us a somewhat less severe condition for AP1000. So it's another change we made to improve the situation for that design.

(Slide change.)

MR. SCHULZ: If you look at -- and again, we've done the analysis of several small LOCAs for AP1000. This is a direct vessel injection line break. And it's showing you the upper plenum mixture levels. It's kind of a little hard to show this. This spike early on is actually AP600. AP1000 doesn't behave quite the same way and it doesn't mainly because AP1000 is a little bigger plant and it's the same break size, so you don't get quite as much rapid blow down early on.

Later on, the response is actually fairly similar, not exactly the same. AP600 has a little dip in here when fourth stage is trying to get the pressure down for IRWST injection. AP1000 actually has IRWST injection starting a little bit earlier, but it's not continuous. That's why you're getting some of these spikes.

MEMBER WALLIS: Those periodic spikes, what are they for? What are they due to?

MR. SCHULZ: You're getting intermittent IRWST injection and when you get the --

MEMBER WALLIS: Then it gets starved and then you --

MR. SCHULZ: So when you get injection, the level goes up, but --

MEMBER WALLIS: But it seems to go down --

MR. SCHULZ: You can't quite keep the pressure down, so the injection slows down and the water level comes back down again. We saw things like that at OSU and it's something that the plant, AP600 is doing some of it also, not as pronounced.

MEMBER WALLIS: You see spikes like that, though you wonder about the peer program because the turn around, it's like the stock market. It's headed for disaster there and then somehow it turns around, but the accuracy with your computer program has something to do with the depth of the spike there.

MR. SCHULZ: Yes, yes.

MEMBER WALLIS: That makes one a little bit concerned. Things happen so quickly in the spike.

MR. SCHULZ: We've got several feet here and this time scale, of course, is a very long time scale.

But that's something that certainly,

should be looked at in more detail when we get into real safety analysis.

DR. ROSEN: What does ADS stand for?

MR. SCHULZ: Automatic depressurization system. I moved my slide. But there are valves connected to the pressurizer which are stages 1, 2 and 3. These are all sequenced to give you a staged depressurization. Stage 4 is actually connected on the hot legs and goes directly to containment. Stage 1, 2 and 3 go from the pressurizer into a sparger in the IRWST. And those valves are all staged so that the transient on the reactor coolant system is less severe.

MEMBER WALLIS: Going back to the spikes, this is sort of the place where you'd like to do some sensitivity studies to see if you have a sort of somewhat different disengagement model for the vapor, whatever the model is. I was sensitive of these things to those features in the code and you want to know there are some assumptions you make which would make those more exaggerated.

(Slide change.)

MR. SCHULZ: Yes. In summary, in terms of safety margins, I haven't talked about the loss of flow, but that's when the reactor coolant pump inertia

is important. And you can see AP1000 may be a little bit less margin than AP600, but both will be comfortably more than the typical operating plant.

Same with the feedline break subcooling margin which I talked about. Steam generator tube rupture analysis, AP600 displayed a significantly enhanced behavior relative to operating plants which did not require any operator action to mitigate a steam generator tube rupture. We've done some preliminary analysis on AP1000 and had the same result. We don't need operator reactions to mitigate a steam generator tube rupture.

Small LOCA, we've done several. Not the full spectrum, but several breaks for AP1000 and we're getting no core uncovery for these smaller breaks like AP600. I've already talked about large break LOCA. That's the same result you saw before.

MEMBER LEITCH: Isn't that 300 degree increase and decladding temperature surprising? I mean when I look at the data I was surprised by that much of an increase.

MR. SCHULZ: Realize where this is coming from. This is basically taking AP600 very carefully detailed calculated re-flood temperature rise and rationing that temperature rise based on the higher

power density of AP1000 and that's where that number is coming from.

MEMBER WALLIS: It's not a thermal hydraulic code calculation?

MR. SCHULZ: It's not a thermal hydraulic code calculation, but we would expect it to go up. Now whether that's where we end up, we won't know until we actually do the detailed large break LOCA analysis. But this kind of a manipulation is we've done it before on new plant designs and it's something you can get a reasonable handle.

MEMBER LEITCH: Yes, I see. Thank you.

MEMBER WALLIS: If it wasn't the criteria, do you think you might tweak your design to get the desired PCT rather than finding what PCT you just happened to get?

MR. SCHULZ: Well, we actually considered running the accumulators faster. We can do that. However, they also empty quicker and there's other transients, especially in PRA space where the accumulator is say the only means of defense at high pressure because we've had common mode failure of the core makeup tanks which is not a design basis consideration, but it is something we consider in the PRA.

And running the accumulator faster there is not good in terms of the balance of safety here between large break LOCA and small break LOCA. So after considering that the PRA sequences, we felt that it was better to run the accumulator the same speed and take a little less margin in large break LOCA and again, it says good or better than a lot of operating plants. So we don't feel uncomfortable with the large break LOCA.

MEMBER WALLIS: But generally speaking, you are asking for somewhat less margin in all of these areas than you have with AP600?

MR. SCHULZ: No. I don't think that's true.

MEMBER WALLIS: Aren't all the numbers --

MR. SCHULZ: Well, small break LOCA, we're basically saying they're the same. If you look at the capability at stage 4 at IRWST injection and recirculation, we think we've actually added more margin into the design and so we'd expect that performance to be probably a little better.

Some of the other cases, yes. Feedline break is a little bit less, but again, it's much better than operating plants.

I need to wrap up pretty quickly here.

(Slide change.)

MR. SCHULZ: The containment comparison, as Mike showed, we've made the containment higher. It's about 22 percent bigger in free volume. We've also increase the design pressure from 45 psig to 59 psig. It's a steel shell containment so we're getting that pressure increased by increasing the thickness a little bit, changing the material and we've also increased the amount of water that's on top of the containment so that we can account for the increase in decay heat.

MEMBER POWERS: Did you change your configuration around there, the hatchway?

MR. SCHULZ: You're talking about the containment hatch?

MEMBER POWERS: Right.

MR. SCHULZ: We actually ended up making the hatch smaller.

MEMBER POWERS: It looks like it.

MR. SCHULZ: Yes. This hatch is sized to remove a steam generator. Because our steam generators got so big that we've decided that's not practical to remove the steam generators out the side and we would have to cut a hole in the top of the containment and remove it through the containment

shell.

MEMBER POWERS: So your vulnerable location around the hatchway is not so bad now?

MR. SCHULZ: That's right.

MEMBER SIEBER: The containment itself has no sizeable concrete structure on the outside, I take it?

MR. SCHULZ: It's a steel pressure vessel that's 1-3/4th inch thick. There is a separate shield building, a concrete shield building that's offset from that and that actually in our case provides the air inlet which comes down outside of a baffle that's in between, turns and goes up closer, with closer spacing relative to the containment and that's part of our passive containment heat removal.

MEMBER SIEBER: How thick is the concrete in the wall there?

MR. SCHULZ: It's about 3 feet.

MEMBER SIEBER: So it has the equivalent shielding capability for severe accident capability?

MR. SCHULZ: Oh yes, for severe accident, missile shields, radiation shielding, yes.

MEMBER SIEBER: Thank you.

DR. ROSEN: Have you actually done a steam generator removal study for the AP1000?

MR. SCHULZ: I think so, yes. Yes, we have. Yes.

(Slide change.)

MR. SCHULZ: And the final slide I have here speaks to the containment performance. We looked at both large LOCA and large steam line break. The large LOCA has a very similar response to AP600 where the first peak is significantly below the design pressure. The second peak is also well below design pressure, assuming more realistic steam generator energy input. This was an issue discussed a lot on AP600. Our SSAR results show a much higher second peak, but it has a very overly conservative sort of unmechanistic transfer of heat from the steam generator into the reactor coolant system.

The steamline break is limiting in this plant. However, it's a much simpler analysis in that it happens early and the passive containment cooling is not really much of a factor in this peak. So how well the passive system performs is it's just more simple volume and some passive heat sinks involved.

Are there any questions?

MEMBER SIEBER: Do you use sprays to control the containment pressure?

MR. SCHULZ: No. There are no sprays in

the plant from a design basis point of view. So all the heat removal is through the passive containment cooling system and the passive heat sinks in the plant. There is a connection to the fire system, but it's a sort of PRA-type severe accident capability that takes manual alignment and it's a long-term type operation. It would not be effective in a short-term peak pressure situation.

MEMBER WALLIS: Okay, shall we move on?

MR. SCHULZ: Yes.

MEMBER WALLIS: Thank you very much.

MR. SCHULZ: You're welcome.

(Slide change.)

MR. BROWN: Okay, we'll move on to --

MEMBER WALLIS: This is an open session, is it?

MR. BROWN: Yes, there is nothing proprietary here.

I am Bill Brown from Westinghouse and I'll be going over the AP1000 PIRT and scaling assessment that was done.

(Slide change.)

MR. BROWN: We had already submitted our report and last month here we met with the Thermal Hydraulic Subcommittee and I made a rather lengthy

presentation on that of which I will try to go through quickly.

The main goals here was to try to determine the extent to which AP600 could be used for AP1000 and our main goal was to be able to use this database for code validation in accordance with 10 CFR Part 52.

The basic steps we used was first, take the PIRTs which identify all the phenomena, have them reviewed again by several experts for application to AP1000 and then take the results of these and look at the high ranked, important phenomena and then assess that relative to AP1000.

(Slide change.)

MR. BROWN: This gives you a quick idea of some of the experts that we talked to, Dr. Bajorek, Dr. Bankoff, Dr. Hochreiter from Penn State, Dr. Peterson from UC and Dr. Larson and Mr. Wilson from INEEL. The main result of this was that we really found that there was very, very few changes whatsoever. Large break LOCA indicated that core entrainment was a little bit higher and in the small break LOCA we found that entrainment again in the ADS-4 two-phase pressure drop was increased and we had no changes whatsoever for the containment and/or for the

non-LOCA transients. So essentially, we're looking at really virtually no change for the AP1000.

(Slide change.)

MR. BROWN: We addressed quite a significant amount of phenomena here and this gives you kind of a flavor for the types of things that we looked at: reactor vessel inventory, core exit quality, ADS floor, injection through the sump and the CMT, containment pressure, the heat and mass transfer to sinks on containment. We looked at these more from what I would call a system level top down and then sort of bottom up we looked at some more detail or local phenomenon such as entrainment, surge line pressure drop, phase separation and so on.

(Slide change.)

MR. BROWN: The basic approach in the scaling that we used for assessment was we focused in on the high-ranked phenomena especially for the areas in AP600 where certainly major interest would seem to be the small break LOCAs since we were interested in the core cooling and the vessel inventory, and then of course, containment pressure and steam line break.

Areas in which we already have data that are found in convention PRW data bases such as large break LOCA phenomena, blowdown and steam generator

recirculation, things like these, we didn't really look at these. We looked at the things which were unique to the passive plants and which we were interested in making sure that we could use the data from AP600. And we did not go in and assess things that were of low importance. We focused on the high level.

(Slide change.)

MR. BROWN: So we started from using our AP600 scaling analysis as our basis. We tried, of course, to learn from what we had discovered from AP600 and tried to look at the major features which were different such as the things you've heard before earlier discussed about core power, volume, the automatic depressurization system area and how these things would compare.

And what we essentially found for the separate effects type test we really look at the operating conditions and the geometric similarities with those. When we got into things such as the integral effects tests, we really had to do some supplemental scaling analysis.

(Slide change.)

MR. BROWN: To give you an idea, a flavor of the type of -- again, the number of tests that we

looked at in AP600 which was something in the neighborhood of a $40 million program, quite extensive, we had a couple of integral effects tests, SPES, OSU, ROSA-AP600 which was NRC funded.

We had a large scale test facility for containment and we had a whole host of separate effects tests for the automatic pressurization system, the core makeup tanks, the passive RHR heat exchanger and numerous containment tests for the heat and mass transfer for the plates that we had and their vertical surfaces in containment, the water distribution and so on. And for all of these, we provided an assessment and for several of these we actually did a new scaling analysis for.

MEMBER KRESS: I don't recall the University of Wisconsin Condensation Test.

MR. BROWN: Yes, that was the condensation tests that were done at -- with the Coradini people up there.

MEMBER KRESS: The effects of non --

DR. ROSEN: That was the flat-plate tests.

MR. BROWN: Yes, that was the flat-plate tests, yes, right.

MEMBER WALLIS: I was thinking about the scaling analysis. You showed us a lot of comparisons

with just sort of this effect versus that effect and their imbalance about the same in the experiment is in the real thing and there was a number that should be 1 and it's 1.1 or something you showed us. But those were sort of pair by pair and something like OSU, OSU actually tries to model the whole thing and you've got many things that interact during the whole transient. I think your scaling analysis was more pair by pair, so you wouldn't be able to -- OSU was design to model AP600 everywhere.

MR. BROWN: It's an integral effects test.

MEMBER WALLIS: OA models AP1000 every -- it may have -- this pair of effects may be in balance, but when you put the whole thing together, it's not going to be quite a model of AP1000, is it?

MR. BROWN: There will be as any of the integral effects test facility, there are things of lower importance of which are not in exact balance and part of the premise of this was that we had established by going through AP600 very painfully that there was a number of things in there which don't become important and some of them simply because they're not active.

For example, once the automatic depressurization system goes off, the passive RHR, the

core makeup tanks, for example, can essentially be drained and it was found both numerically doing the analysis as well as though the tests that the energy removal of these components is very small. You can go ahead and scale them, but they're not very significant.

MEMBER WALLIS: That was not very clear. You looked to scaling as CNTs and injection from the IRWST, all of these. If you scaled each one of those phenomena, but in the whole transient, they're all interdependent. At the starting point for one phase is where you've finished at the previous phase, the effects go through the transient. Really, you have to run the code or something to get the whole system effect.

MR. BROWN: We do break the scaling up into phases, yes. We do not have, if you're looking for an analysis which would start from time zero and look at the whole snapshot, yes, we do, we do break them up.

MEMBER WALLIS: OSU is sort of trying to scale everything after a certain time.

MR. BROWN: We find OSU is particularly good once the system is low pressure. It's a low pressure facility and not surprisingly you find that

it's very well scaled once the system is depressurized to low pressure.

MEMBER WALLIS: The thing I'm getting at is that the interactions between the systems, other than in pairs really has to be modeled by something like a thermal hydraulic code for scaling analysis balances.

MR. BROWN: Yes, you get to the point with scaling where you very quickly and I think Dr. Zuber found this out in AP600, although he had the vision of this, you pretty quickly get to the point that in order to be able to work with the set of equations that very quickly you put the complexity in where you now need a code to solve them and you no longer have a scaling analysis.

But one of the things that I think we've gone to be able to help that out is one knowing, for example, that no all, even though we have all of these passive components, potentially available, not all of them are operating at each phase during a small or LOCA transient. Not all of them are always significant. And you can also determine that by scaling and the testing to bear that out. I mean, for example, we have a small break LOCA, that's a one inch or a two inch break.

It's very important during the blow down phase and during natural circulation, once you open up this huge hole, we call on automatic depressurization system there. Suddenly, the mass and energy out of this break becomes nothing, so I could continue to scale this for you, but we find it's not significant and that's why I didn't bother focusing that in this report. We focused on the things that were important when they were important.

And we have reams and reams of notebooks in AP600 that were submitted and we went through that process significantly. I attempted to do that and put all the components in each particular phase that were all active. In many cases, I painfully found out that many of them were just simply not important.

There was questions like, for example, momentum distribution effects once the ADS system went off and we pretty much found that maybe other than the surge line which leads up to the ADS 1, 2, 3, it's pretty much their pressure distribution around the system. It's not very significant while the system is in critical flow.

Okay?

MEMBER LEITCH: There's a statement in the executive summary of the blue book here that puzzles

me a little bit. Basically it says that starting with the AP600 and then demonstrating through scaling that the -- I'm sorry, starting with the AP1000 and then demonstrating through scaling that the AP600 program applies to the AP1000 and therefore that the AP600 analysis codes are applicable to the AP1000.

It seems to me that you're saying through scaling the test programs are comparable or can be scaled?

MR. BROWN: Yes.

MEMBER LEITCH: And then you say and therefore the analysis codes can be scaled. That's not intuitive obvious to me.

MR. BROWN: I guess we need to restate to what was probably intended is that if we have a set of scaled facilities and through scaling we determine that they cover the most important phenomena that we expect to see in the full-scale test and we have demonstrated though scaling that these test facilities are applicable to the full-scale plant and therefore we say now if the codes which in AP600 they were, the codes were then validated to that database, and if the scaling still exists between the test facilities to AP1000 therefore, we should be able to use those same

validated codes because now we're validating to the same data base and we're saying as long as it's still applicable and that's the key, if through scaling it's still applicable, therefore the codes are also now validated for an AP1000.

So you're basically saying if my codes can predict the test facility and the test facility is sufficiently scaled to the plant, I can use them to predict the plant performance. That's the philosophy. That's what was done in AP600 and we're taking the same philosophy here.

MEMBER LEITCH: Okay.

(Slide change.)

MR. BROWN: So the major results that came up here, similar to AP600, we were able to find at least one integral effects test facility for each phase of a small break LOCA transient which was able to address the important phenomena to AP600 to that it was suitable for code validation and we found specifically that, for example, the SPES facility was acceptable through the high pressure phase of a transient, but it became distorted after the ADS 4 which is our biggest flow path would open up and goes to subsonic.

But on the other hand, we were able to

cover that because we've got OSU which is good at the low pressure phases.

MEMBER KRESS: When you say distorted, the time rate of change of things are different.

MR. BROWN: Yes, like for example, you do get a -- because of the vent area relative to the volume, for example, you can get a distortion with that.

MEMBER KRESS: But you go through the same set of phenomena.

MR. BROWN: Yes, you do.

MEMBER KRESS: So you don't distort the phenomena.

MR. BROWN: Yes.

MEMBER KRESS: You just distort the --

MR. BROWN: The timing.

MEMBER KRESS: The way timing goes.

MR. BROWN: Yes. And I think that's sometimes a bit of an issue with the consultants at times with the scaling and I would say that really if you want to go back and take out time in here, we're very well scaled. I mean even better. But when you actually factor in the timing in here which I've done as well, you can find that maybe some of the facilities are better scaled with actually preserving

the time in which you would --

MEMBER WALLIS: This would really muddle the phenomenon, the timing wouldn't be important.

MEMBER KRESS: That's right. That's what you're saying. You know the timing is going to be different anyway for the scaled test.

MR. BROWN: It's hard to preserve.

MEMBER KRESS: You can't preserve the whole thing.

MR. BROWN: Right. It certainly helps if you can get the timing as well. That's certainly a bonus if you can do that, yes.

That's really the only difference. I think that's the best way to think about this plant really. You're really boiling down to things like volume and area and power and you're talking about timing. I mean really we're not talking about any different phenomenon. That's why our position on the codes are, we have the same phenomena. Our experts tell us we have the same phenomena. We have it covered in the tests and we're really talking about the rate at which it happens. That's it.

And if we can't model volumes and areas and powers, I think we probably better quick. It should be --

MEMBER KRESS: You have to get to the momentum equation.

(Laughter.)

(Slide change.)

MR. BROWN: We found also over our Separate Effects Test also again covered our ranges and we've got the same phenomena, so we think that those are applicable.

With regard to some pass of the containment cooling system, with regard to this pressure transient issue which you just mentioned, Dr. Kress, we still found we have our large scale test facility for containment is very good for evaluating heat and mass transfer correlations, but because of the power to volume distortion, if you will, the timing of the pressure transient is not perfectly preserved to an AP600, so it's not a good representation of a pressure transient, but it certainly has the appropriate phenomenon to use for heat and mass transfer correlations.

MEMBER KRESS: When you get a condensation on the walls of something like that, actually the rate of condensation gets to be important in terms of the effect of noncondensibles. I was -- my question on that is were your separate effects test able to cover

the same rate of condensation that you expect to get here, rate per unit area isi what I am interested in.

MR. BROWN: Yes. We have the -- if you want to look at heat flux, we looked at things like the Reynolds number of the film, that type of thing. Yes, we're still -- in the AP600, we did a very good job, I think, of being able to cover the range because were trying to anticipate a very wide variation in these things. So there is a very significant range that's covered in those tests. Very large range. And it's in some of the tables in that report if you look back in the containment section you'll see the large range that was in there. I didn't think we had enough time to go through that here.

We also had done some CFD analysis which was very simple. It was a 2-D slab. We weren't trying to claim that this was -- you're shaking your head already.

MEMBER WALLIS: Unacceptable.

MR. BROWN: What we were trying to address here was the height to diameter effect. I mean because one of the questions I think that we asked ourselves right away was well, mixing and stratification was of interest in AP600. This is a very big plant. And we were increasing it by 25 more

feet and we wanted to ask ourselves well, given whatever AP600 is, how do we compare to this? So we used this as a tool.

When we presented this to the Thermal Hydraulic Subcommittee, Dr. Wallis asked us if we could just simply rotate this in 3-D and see whether or not we could look at the three dimensional effects as well. I see he's still shaking his head.

MEMBER WALLIS: It's a different problem. I mean drawing of a plank is different from drawing a log. Cylindrical geometry is not a plane. It's different.

MR. BROWN: I agree. The attempt was to try to look at what the --

MEMBER WALLIS: I think the attempt was good. Now you have to -- right.

MR. BROWN: That's a start.

MEMBER KRESS: If you're just validating that your containment is well mixed, I think the ability to well mix 2-D is harder than to well mix the 3-D and if you can do it with the 2-D, you ought to be able to do it with the 3-D.

What do you think, Graham?

MEMBER WALLIS: I don't know. Maybe you're more easily convinced than I am.

MEMBER KRESS: I say that because --

MEMBER SHACK: It's only a 2-D problem. It's just an axis symmetric 2-D problem not a plane 2-D problem.

MEMBER WALLIS: So just use polycoordinates and solve the equations. It's simple.

MR. BROWN: All right. We can scale it.

MEMBER WALLIS: I don't know, what fluent does is simply says are you using polycoordinates or Cartesian. You say one or the other and it solves it. You just have to make that decision, that's all.

MR. BROWN: There's a lot of mesh generation, a lot of babysitting.

MEMBER WALLIS: Well, most CFD codes just generate the mesh for you. You should do it.

MEMBER KRESS: You should do it just to satisfy the naysayers. It's good for your soul.

MR. BROWN: Okay. Comment received.

MEMBER WALLIS: Hit me with the bottom line. Is it well mixed or just stratified?

(Laughter.)

MR. BROWN: Well, what we found, what we saw in the 2-D was we really saw virtually no difference. It was very well mixed. In fact, it was probably better mixed. It was almost -- when you got

to the near last several inches of the boundary there, you couldn't see any gradient whatsoever. It was very well mixed.

MEMBER KRESS: As I casually mentioned in the subcommittee meeting, you're better off if it's not --

MR. BROWN: Say it a little louder. Right, that was good.

(Laughter.)

We're really trying to say is if we allow the steam to even allow it to stratify, it's even better because we have this nice Raley-Bernard convection problem with this very cold surface on top of a hot surface, which you would expect would mix pretty well.

(Slide change.)

MR. BROWN: In conclusion then, we found that -- we think that the phenomena looks similar to AP1000. We think we have the test, both separate effects and we can find at least one integral effects test to cover each phase of the AP1000 small break LOCA transient and therefore our analysis codes can be validated here and therefore are applicable to AP1000 and so therefore we should have a sufficient database for code validation in accordance with the

requirements of 10 CFR Part 52.

MEMBER WALLIS: Now that may be a reasonable conclusion. It doesn't mean to say that you'll reach the same conclusions about AP1000 that you did about AP600 when you actually run the codes because it may turn out that these small changes in geometry and the mass, be more mass here than there and so on, actually have fairly significant effect on something that matters when you go from 600 to 1000.

MR. BROWN: I agree with you. And all we're saying is we can use the same tool to predict that, that's all we're trying to get across here. We agree that the answers could look a bit different and I would be a little worried if they didn't probably if they looked exactly -- we really expect that we're saying is we have the same similar phenomenon so therefore we can use the same tool.

MEMBER WALLIS: When we look at those answers and we look at sensitivities, it may be that you have to get something righter than 1000, let's say like entrainment from the vessel or something. You have to model something better with 1000 or maybe less, less well.

MR. BROWN: We need the approved Dr. Graham Wallis correlation first to do that because

what else is out there isn't --

MEMBER WALLIS: I haven't had correlations for some time.

MR. BROWN: We need another one.

(Laughter.)

MR. BROWN: What's out there right now.

Any other questions?

DR. ROSEN: The stage 4 operation of the ADS, how does one test that during normal operation of the plant?

MR. BROWN: Terry could probably address that, Terry Schulz.

MR. SCHULZ: This is Terry Schulz from Westinghouse. The stage 4 valves are squib valves. So they're not cycled in the plant. The ASME code addresses squib valves in terms of in-service testing and what they allow you to do is to remove periodically and this is on like a 5 to 8 year basis the propellant that would actually operate the valve and that's the main question about the operability of the valve because everything else is pretty passive and simple in terms of the operation.

And you remove that after it's been in service and you go into a test fixture and actually fire it in a test fixture and determine if it would

have operated. And by doing this you can then and also in terms of the quality and QHX on the propellants that you trace through the life from when you first made the propellants until you've checked it, that's what you would do.

You would also do some inspections to make sure the pipes are not plugged up or something like that, but the geometry is very simple in the stage four. It's not very complicated at all, very short pipes, big pipes. The main thing is whether the valve would operate or not and that's addressed in ASME code.

DR. ROSEN: What size valves are those?

MR. SCHULZ: In AP600, they're 10-inch. On the AP1000, they're 14-inch.

DR. UHRIG: Terry, on the squib valves, do you do continuity testing on the circuitry from time to time?

MR. SCHULZ: I know we discussed that on AP600 and I'm trying to remember what we concluded. I think we concluded that we would at least periodically do that, like when we change the propellant. We would not do it continuously. I don't know if there's anything else we committed to do.

DR. UHRIG: I'm just wondering because you

say 5 to 8 years. I'm wondering just like every year or something, you might test the conduit of the circuit to make sure that's --

MR. SCHULZ: I'm not 100 percent sure of what we committed to there.

DR. UHRIG: Thank you.

MR. BROWN: Any other questions? Okay. Thank you.

(Slide change.)

MR. GRESHAM: Good afternoon. My name is Jim Gresham. I'm with Westinghouse and I have just a few slides here to give you an overview of the approach on codes and analysis for AP1000.

(Slide change.)

MR. GRESHAM: As has been mentioned at least twice already today, probably more, we're starting with the computer codes that were used for AP600 and approved for that application and just assessing the differences in the plant and design test and so forth. So from that starting point we're confirming the adequacy of these codes for the AP1000 design and I have another slide that talks about the steps in that.

Any potential concerns that there are in that review we'll have to address and as well as that

in the AP600 review and in the AP600 FSER, there were some concerns with the codes mentioned. We are addressing all of those.

MEMBER WALLIS: I wonder how you can do this ahead of time. It seems to me that you have to actually exercise the code for AP1000 and see what kind of things you're getting from it and if you find something which concerns you, which didn't concern you with AP600 then you're going to have to say it's not quite the same. I don't think you have a carte blanche that says because it worked for 600, it must work for every aspect of 1000.

MR. GRESHAM: I would agree with that. Some of the items that were mentioned on AP600 I think we have to deal with up front. But you're right in that as you look at the analysis results you'll see things and you need to understand why.

MEMBER WALLIS: So I don't know that we can -- you can reach consensus on this as a starting point. I don't think we can reach consensus early on about acceptability until we see how it works.

MR. GRESHAM: Yes, I agree with that statement.

MEMBER WALLIS: Thank you.

(Slide change.)

MR. GRESHAM: The steps that we used or are using to confirm the adequacy of the codes is first to look at the important phenomenon that exists in the plant and this has been done through the PIRT in the scaling report which Bill already discussed with you.

We need to identify the correlations and the models that are used in each of the codes to analyze the important phenomena in the design and since we're starting with the AP600 approved codes and have confirmed the phenomena are the same, that's already been done in the AP600 design certification process. We're relying a lot on that information.

Then demonstrate that the test data are adequate and for validation of the codes and that has been demonstrated in the scaling in the PIRT work and then as I mentioned we have to demonstrate that the limitations that have already been identified are being adequately addressed.

MEMBER WALLIS: And to reiterate, there may be some other limitations that emerge when you start working on AP1000. We don't know if there will be, but there might be.

MR. GRESHAM: Yes, there might be and --

MEMBER WALLIS: Just the fact that you

have addressed the AP600 ones doesn't mean that you've found all the ones that might apply to 1000.

MR. GRESHAM: Yes. We have some confidence as we proceed through here because nothing is identified in the PIRT or the scaling work, but certainly all the way through here, we need to be on the look out for that.

(Slide change.)

MR. GRESHAM: There are several ways that we may choose to address these limitations. And these include, there may be one or more of any of these, but it's possible to change the design. Terry talked about some of the changes in the design that has led to actually more margin in some cases.

We may find the phenomena that we feel like we need to do some additional validation to test to understand the effects better and then complete the story relative to the codes.

Just by evaluating that there's a lot of margin in some area may be, may go toward addressing limitation in the code.

We will do in some cases additional analyses such as the CFD calculations that we already discussed to address a limitation for a code or in some portion of the code, either a portion of the

transient where different phenomena are occurring or a particular model that the code has to be able to show that we have some concerns about. And use this analysis not as the safety analysis in the SSAR, but as additional information to show the effects that will occur in the plant that are predicted to occur in the plant. And there may be some cases, we have not found any yet, but there may be some cases where we believe that we need to make changes to the codes.

MEMBER WALLIS: Well, there's carryover into the AS fall line, carryover -- do you have a bigger radius for it, do you have higher velocities, maybe? I don't know what you have.

MR. GRESHAM: It isi larger. The ADS is 10 to 14 inch.

MEMBER WALLIS: How well do you model that actual entrainment to the Aegis fall out?

MR. GRESHAM: Yes. I'm not sure about the velocities.

MEMBER KRESS: I was about to say it's still sonic velocity.

MEMBER WALLIS: No, no, it's actually at the hot leg.

MEMBER KRESS: It's about the same temperature.

MEMBER WALLIS: It's about the same?

MR. SCHULZ: This is Terry Schulz from Westinghouse. The connection to the hot leg is actually an increase from like 12 inches to 18 inches, so it's gone up more than the power has gone up.

MEMBER WALLIS: So you've got more than the hot leg.

MEMBER KRESS: You get more flow.

MR. SCHULZ: No, the hot leg is 31 inches in diameter.

MEMBER WALLIS: It's a different diameter ratio of hot leg to ADS fall line?

MR. SCHULZ: Yes.

MEMBER WALLIS: So you might have to do something about modeling that. It is different geometry than the fall.

MR. SCHULZ: Yes.

(Slide change.)

MR. GRESHAM: We are working on a report to give to the staff, the Code Applicability Report where we will discuss the important phenomena, referencing back to the work that was done on the PIRT in the scaling, to provide a description of the codes that we're using to analyze the different accidents for AP1000 and look at the code applicability of the

AP600 codes for application to AP1000 and much of the information is in the FSER and some of the documents that we provided in support of that and the limitations that were identified are also discussed in the FSER and we will go through each of these and describe how we believe that we're addressing those.

MEMBER WALLIS: Now you said you'd supply a code description. The staff has been actually asking for the code itself from other applicants and has been getting it and that's something that this committee is much in favor of, actually having the code itself examined and run by the staff. That gives assurance that it's user independent. You get the same answer and you can investigate things. Everything is in the open. It would be very desirable if that could happen here.

MR. GRESHAM: Well, we're asking the staff to look at the code applicability report when they get it and discuss --

MEMBER WALLIS: It's all based on submissions by Westinghouse.

MR. GRESHAM: Sure.

MEMBER SIEBER: When you're all through with the phenomenon logical modeling that you're doing here, you have the capability to determine the

uncertainty in these phenomenon logical codes?

MR. GRESHAM: Not entirely, no. In the -- we're using the best estimate, large break LOCA methodology using the COBRA track code for the large break and the quantification in the convolution of uncertainties is certainly involved in that.

In most of the other safety analyses, we're using a bounding approach where we're demonstrating that we have a conservative calculation of the consequences of the different accidents and so we're covering the uncertainties in that regard, but in terms of quantifying the uncertainties, we won't have that.

MEMBER SIEBER: So you really won't know how much margin you have either.

MR. GRESHAM: Just lots.

MEMBER SIEBER: I'm not sure that makes -- lots and great are about the same kind of term.

(Laughter.)

MR. GRESHAM: Yes.

MEMBER SIEBER: So the answer is probably won't have very much way to quantify margin and uncertainty when you're --

MR. GRESHAM: That's right. We won't have a quantification.

MEMBER WALLIS: So on the issue of supplying the code to the staff, is that something which is still under negotiation?

MR. GRESHAM: Yes, it is.

MEMBER WALLIS: Have you folks seen the light yet?

MR. GRESHAM: It's still under negotiation.

Any other questions?

DR. ROSEN: The ADS, as I understood it, the stage 4 is different in AP1000?

MR. GRESHAM: Yes, it is.

DR. ROSEN: It's not in AP600?

MR. GRESHAM: No, it is in AP600, but it's larger in the -- I'm sorry, larger in the AP1000. Stages 1, 2 and 3 are the same size, but stage 4 is larger in AP1000.

DR. ROSEN: Does the AP1000 have a different estimated core damage frequency than the AP600?

MR. GRESHAM: I don't believe we've calculated that yet. We have not done the PRA.

MR. SCHULZ: This is Terry Schulz from Westinghouse. Jim is right. We have not calculated that number, but the design approach that we are

taking relative to PRA is to size the components and arrange the systems in terms of the same arrangements, same number of valves, same type of valves, so that the reliability of the system would be expected to be the same.

We're trying to from a preliminary design point of view, have the same success criterion in terms of the number of ADS valves, number of components required, so we've actually done some preliminary T & H analysis with multiple failures to try to check our success criteria. And that's not been done formally and that's not going to be part of this Phase 2 staff review of AP1000, but our design approach is to try to end up with the same core melt frequency by using the same configuration, same type of components and same success criteria.

DR. ROSEN: Of course, the ADS valves are larger for AP1000 than they are for AP600 so their reliability might be different.

MR. SCHULZ: That's usually not a strong factor in the quantified reliabilities of components within some limitations, of course.

MEMBER WALLIS: Can we move on?

MR. GRESHAM: Okay.

MEMBER WALLIS: We're a little bit behind,

Mr. Chairman, but I think we have a little elasticity in the schedule that's coming up.

VICE CHAIRMAN BONACA: Yes, we do.

(Slide change.)

MR. ORR: My name is Richard Orr and at Westinghouse I'm responsible for the design of the structures and the seismic analyses and I'll cover very briefly some of the evaluation of the structural changes and then get into the discussion of the approach to design certification.

(Slide change.)

MR. ORR: As Mike and Terry have described, we have attempted to keep the configuration as close as possible for AP1000 to AP600. The configuration was described in a report submitted to NRC at the end of last year. From a structural point of view, the main differences are the height of containment and associated with that, the height of the shield building, so going from AP600 to AP1000, everything above this elevation moves up 25 feet.

In plan view, everything looks the same so the major change, as I say, is just this increase in elevation.

We have evaluated these differences and concluded that we can accommodate them in the

structural design.

MEMBER POWERS: Not everything is the same, down below there, though, is it? Aren't the steam generators --

MR. ORR: As far as structure is concerned, it is identical. The steam generators are bigger.

MEMBER POWERS: But that's not identical.

MR. ORR: Let me get directly to my next slide.

(Slide change.)

MR. ORR: In our evaluation of the changes, we have conducted a seismic analysis of the nuclear island and used methodology identical to AP600, adjusted the models for the changes for AP1000 and this includes raising the shield building 25 feet, increasing the shield building roof, the PCS tank from 540,000 to 800,000 gallons. We include in the analysis the containment vessel which is a little bit taller and an increased thickness. We include the structures inside containment.

The only changes in the structures there are the shield walls around the steam generator and pressurizer have been extended upwards a little bit for shielding. And we include in the analysis the

reactor coolant loop which has been modified to include the bigger steam generators and the bigger pumps.

All of these items are included in this single model and I'm showing here some typical results. There's a lot more results. All I want to do is highlight three of them here that I've marked.

MEMBER WALLIS: Excuse me. North, southeast, west has something to do with steam generators.

MR. ORR: No. North, southeast, west is strictly an orientation we've established for the plan view of the AP600. North is towards the turbine building.

MEMBER WALLIS: So the difference is that the steam generators are on one side or something? What's different about it?

MR. ORR: About?

MEMBER WALLIS: The two axes, what's -- it looks sort of -- it's a symmetrical building, isn't it?

MR. ORR: No, the footprint, the shield building and the containment sit on a base mat and are integral with the auxiliary building.

MEMBER WALLIS: Okay, that's what makes

the difference.

MR. ORR: The long access is the north-south axis. The short access is the east-west axis.

If we look first of all at the seismic response at the highest elevation at the top of the shield building, the acceleration and this is for a three-tenths g input on a hard rock site, the acceleration response increases from 1.47g to 1.54, an increase of about 5 percent. And this is really the one that controls the design of the shield building roof and the 800,000 gallons of water. We have, indeed, done preliminary design of the shield building roof and demonstrated that yeah, we can add some sufficient reinforcement. There's no problem.

Next one I want to show is what we term base shear. This is sort of the shear force at grade elevation that is very significant in the design of the shear walls, the shield building and the walls in the auxiliary building. Here, the shear in the north-south direction which is the one that increases the most, increases from 37.5 to 46.8 which I think is 20 percent if I recall, 25 percent, sorry.

And the other one I want to point out is the overturning moment, again, at grade elevation and

for about the north-south axis which is the shorter of the axes, it increases from 4100 to 5500 which is a 33 percent increase.

We have looked at the effect of this on design of the structure. We find no problems in sort of the design of AP1000.

I should just point out one of these numbers is higher. About the east-west axis, I haven't identified that as a problem. This is the long axis of the building and it's much easier to accommodate in the design.

MEMBER SIEBER: None of this includes the effect of soil liquification?

MR. ORR: These are all for hard rock.

MEMBER SIEBER: Hard rock.

MR. ORR: We have a site interface established that says there shall be no soil liquefaction. That is something the combined license has to demonstrate for his site.

MEMBER SIEBER: So that means if you build a plant like this, you put it on franky piles or something like that to get the hard rock support?

MR. ORR: Not necessarily.

MEMBER SIEBER: That would be a way.

MR. ORR: A hard rock site is acceptable.

Something like 50 percent of the existing nuclear plants are on rock.

MEMBER SIEBER: Yeah.

MR. ORR: A good soil site, there would be no problem. There are one or two soil sites that would sort of require fairly extensive foundation work, but then they did for the existing units that are there already.

MEMBER SIEBER: I was thinking that a lot of the sites may be half or built on river banks which is usually silt.

MR. ORR: Yes.

MEMBER SIEBER: Which is pretty liquid.

MR. ORR: The interface we established on AP600 and would be applicable here as well, is a shear way velocity for the soil greater than the thousand feet per second.

That excludes one or two of those real soft sites. It basically means you've got to dig it all out and replace it by competent material. Certain existing sites have had to do that.

MEMBER SIEBER: Right. Is there a difference between East Coast and West Coast where a plant like this might be precluded --

MR. ORR: We have established the seismic

input design level at three-tenths g which does exclude California for the standard design.

MEMBER SIEBER: Okay, thank you.

MEMBER KRESS: What moment can the containment stand before it buckles? Have you determined that?

MR. ORR: The critical condition for the containment is not internal pressure. It's the combination of external pressure and safe shutdown earthquake. External pressure is a situation where you basically trip the reactor on an extremely cold day and pull the temperature of containment down fairly rapidly and for AP600 that is something like negative pressure of 2.5 psi.

We designed for an external pressure of 3 psi and then we combined that with the safe shutdown earthquake and we were able to demonstrate for AP600 adequate margin. The critical location is at the base of containment. I think, if anything, we'll have a slightly greater margin because we've increased the shell thickness two inch and three quarter versus inch and five-eighths. So it's an evaluation that still needs to be done and it will be included in the Phase 3 part of NRC's review, but I don't expect it to be an issue.

DR. ROSEN: What is the diameter of this containment at the operating floor elevation?

MR. ORR: It's 130 feet. I did check the configuration. It's very, very similar to the dimensions of Comanche Peak. Comanche Peak is 135 foot ID. This is 130 and then the shield building is further out and the total height is almost identical.

MEMBER SIEBER: What's the space between the containment liner and the inner surface of the concrete?

MR. ORR: From the inside surface of the containment vessel to the inside surface of the shield building is a nominal 4 feet 6 inches. So it's got to 4 feet 4 and a quarter.

MEMBER SIEBER: All right, thank you. Which is enough for a stairwell, right?

MR. ORR: Oh yes, you can get in there. In fact, we have designed the air baffle to be removal for inspection and maintenance purposes.

For AP600, we did extensive seismic analysis and structural design. Clearly, sort of for AP1000 we do have some limited resources and there's some, much higher priority safety analysis being performed. So we have suggested, proposed to NRC that we would use design acceptance criteria for the

detailed structural design and seismic analyses at soil sites. This approach has been used on other certified designs, not quite to the same extent.

We would be using the same criteria and methodology and these will be documented in the AP1000 design certification document and we will be identifying certain other key information, constructural configuration which we've described here. We will present results of the seismic analysis for hard rock and present a design of the containment vessel in the design certification document.

This approach was described in a report we submitted to NRC earlier this year. We have had one meeting with them to discuss it. The detailed design analysis would be performed by the combined license applicant, would be presented to the staff at the time of the combined license application, so it would be reviewed and accepted by NRC prior to start of construction.

Once the combined license is issued, then there would still be on-going construction and there would still be the same inspection and acceptance criteria as we have used for AP600.

Thank you. Any questions?

MEMBER WALLIS: Any questions? Any final

words from anyone?

MR. CORLETTI: We have no more words, so if you have any more questions.

MEMBER WALLIS: I thought you were going to give us some final words.

MR. CORLETTI: No, not really.

MEMBER WALLIS: A finale. Well, thank you, Westinghouse very much.

If the committee has no more questions, I'll hand this back to the chairman.

CHAIRMAN APOSTOLAKIS: Thank you, Graham. Thank you, gentlemen.

Now we're scheduled to break and work on preparing draft reports. I'm willing to break, but I'm not sure we need to prepare any reports. Is anybody working on a report? I would rather come back here and read the first draft of what we have and give some advice to the authors and then move on and revisit maybe the Commission meeting or do other things. So why don't we break until 4:50 and then we'll come back and read this.

(Whereupon, the proceeding went off the record at 4:35 p.m.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS Full Committee Meeting

Docket Number: (Not Applicable)

Location: Rockville, Maryland

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Rebecca Davis

Rebecca Davis
Official Reporter
Neal R. Gross & Co., Inc.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D.C. 20555-0001

March 12, 2001

SCHEDULE AND OUTLINE FOR DISCUSSION
481ST ACRS MEETING
APRIL 5-7, 2001

THURSDAY, APRIL 5, 2001, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

1) 8:30 - 8:35 A.M. Opening Remarks by the ACRS Chairman (Open)
- 1.1) Opening statement (GEA/JTL/SD)
- 1.2) Items of current interest (GEA/SD)
- 1.3) Priorities for preparation of ACRS reports (GEA/JTL/SD)

2) 8:35 - 10:30 A.M. Interim Review of the License Renewal Application for Edwin I. Hatch Nuclear Plant Units 1 and 2 (Open) (MVB/GML/SD/RBE)
- 2.1) Remarks by the Subcommittee Chairman
- 2.2) Briefing by and discussions with representatives of the NRC staff and Southern Nuclear Operating Company regarding the license renewal application for Hatch Units 1 and 2, associated staff's Safety Evaluation Report (SER), selected Boiling Water Reactor Vessel and Internals Project (BWRVIP) reports and the related staff's safety evaluations.

10:30 - 10:50 A.M. ***BREAK***

3) 10:50 - 12:00 Noon. Proposed Final License Renewal Guidance Documents (Open) (MVB/GML/SD/RBE)
- 3.1) Remarks by the Subcommittee Chairman
- 3.2) Briefing by and discussions with representatives of the NRC staff regarding the proposed final Regulatory Guide DG-1104 and Standard Review Plan associated with license renewal, Generic Aging Lessons Learned (GALL) report, and Nuclear Energy Institute (NEI) 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule."

Representatives of the nuclear industry will provide their views, as appropriate.

12:00 - 1:00 P.M. ***LUNCH***

4) 1:00 - 2:30 P.M. Safety Issues Associated with the Use of Mixed Oxide (MOX) and High Burnup Fuels (Open) (DAP/MME)
- 4.1) Remarks by the Subcommittee Chairman ✓

2:50

4.2) Briefing by and discussions with representatives of the NRC staff regarding safety issues associated with the use of MOX and high burnup fuels in commercial light water reactors.

Representatives of the nuclear industry will provide their views, as appropriate.

2:30 - 2:50 P.M. *****BREAK*****

5) 2:50 - 4:15 P.M. Thermal-Hydraulic Issues Associated with the AP1000 Passive Plant Design (Open/Closed) (GBW/PAB)
5.1) Remarks by the Subcommittee Chairman
5.2) Briefing by and discussions with representatives of the NRC staff and the Westinghouse Electric Corporation regarding the thermal-hydraulic issues associated with the AP1000 design.

[Note: A portion of this session may be closed to discuss Westinghouse proprietary information applicable to this matter.]

6) 4:15 - 5:15 P.M. Break and Preparation of Draft ACRS Reports
Cognizant ACRS members will prepare draft reports, as needed, for consideration by the full Committee.

7) 5:15 - 7:00 P.M. Proposed ACRS Reports (Open)
Discussion of proposed ACRS reports on:
7.1) Interim Report on the License Renewal Application for Hatch Units 1 and 2 (MVB/GML/SD/RBE)
7.2) Proposed Final License Renewal Guidance Documents (MVB/GML/SD/RBE)
7.3) Safety Issues associated with use of MOX and High Burnup Fuels (DAP/MME)
7.4) Thermal-Hydraulic Issues Associated with the AP1000 Design (GBW/PAB)

FRIDAY, APRIL 6, 2001, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

8) 8:30 - 8:35 A.M. Opening Remarks by the ACRS Chairman (Open) (GEA/JTL/SD)

9) 8:35 - 10:30 A.M. Draft Final Safety Evaluation Report for the South Texas Project Nuclear Operating Company (STPNOC) Exemption Request (Open) (JDS/GEA/MWW)
9.1) Remarks by the Subcommittee Chairman
9.2) Briefing by and discussions with representatives of the NRC staff and STPNOC regarding the staff's draft Final Safety Evaluation Report for the STPNOC exemption request to exclude certain components from the scope of special treatment requirements required by NRC regulations.

10:30 - 10:50 A.M. *****BREAK*****

10) 10:50 - 11:45 A.M. Closure of Generic Safety Issue (GSI)-170, "Reactivity Transients and Fuel Damage Criteria for High Burnup Fuel" (Open) (DAP/MME)
- 10.1) Remarks by the Subcommittee Chairman
- 10.2) Discussion with representatives of the NRC staff, as needed, regarding the closure of GSI-170.

11:45 - 1:00 P.M. ***LUNCH***

11) 1:00 - 1:15 P.M. Subcommittee Report (Open) (WJS/MTM)
Report by the Chairman of the Materials and Metallurgy Subcommittee regarding risk-informing 10 CFR 50.46, which was discussed during a joint meeting of the ACRS Subcommittees on Materials and Metallurgy, Thermal-Hydraulic Phenomena, and Reliability and Probabilistic Risk Assessment on March 16, 2001.

12) 1:15 - 1:45 P.M. Future ACRS Activities/Report of the Planning and Procedures Subcommittee (Open) (GEA/JTL/JEL)
- 12.1) Discussion of the recommendations of the Planning and Procedures Subcommittee regarding items proposed for consideration by the full Committee during future ACRS meetings.
- 12.2) Report of the Planning and Procedures Subcommittee on matters related to the conduct of ACRS business, and organizational and personnel matters relating to the ACRS.

13) 1:45 - 2:00 P.M. Reconciliation of ACRS Comments and Recommendations (Open) (GEA, et al./SD, et al.)
Discussion of the responses from the NRC Executive Director for Operations to comments and recommendations included in recent ACRS reports and letters.

14) 2:00 - 3:00 P.M. Break and Preparation of Draft ACRS Reports
Cognizant ACRS members will prepare draft reports, as needed, for consideration by the full Committee.

15) 3:00 - 7:00 P.M. Proposed ACRS Reports (Open)
Discussion of proposed ACRS reports on:
- 15.1) South Texas Project Exemption Request (JDS/GEA/MWW)
- 15.2) Closure of GSI-170 (DAP/MME)
- 15.3) Interim Report on the License Renewal Application for Hatch Units 1 and 2 (MVB/GML/SD/RBE)
- 15.4) Proposed Final License Renewal Guidance Documents (MVB/GML/SD/RBE)
- 15.5) Safety Issues associated with use of MOX and High Burnup Fuels (DAP/MME)
- 15.6) Thermal-Hydraulic Issues Associated with the AP1000 Design (GBW/PAB)

SATURDAY, APRIL 7, 2001, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

16) 8:30 - 12:30 P.M. Proposed ACRS Reports (Open)
(10:30-10:50 A.M. BREAK) Continue discussion of proposed ACRS reports listed under Item 15.

17) 12:30 - 1:00 P.M. Miscellaneous (Open) (GEA/JTL/JEL)
Discussion of matters related to the conduct of Committee activities and matters and specific issues that were not completed during previous meetings, as time and availability of information permit.

NOTE:

- **Presentation time should not exceed 50 percent of the total time allocated for a specific item. The remaining 50 percent of the time is reserved for discussion.**
- **Number of copies of the presentation materials to be provided to the ACRS - 35.**

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
481st ACRS Meeting
INTERIM REVIEW OF THE LICENSE RENEWAL APPLICATION (LRA) FOR
EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2
APRIL 5, 2001
ROCKVILLE, MARYLAND

- AGENDA -

	TOPIC	PRESENTER	TIME
I.	Opening Remarks	M. Bonaca, ACRS	8:35-8:40 a.m.
II.	Staff Opening Remarks	C. Grimes, NRR	8:40-8:45 a.m.
III.	Boiling Water Reactor Vessel Internals Project (BWRVIP) Topical Reports	G. Carpenter, NRR	8:45-9:15 a.m.
IV.	Southern Nuclear Operating Company (SNC) Presentation on the Hatch LRA	R. Baker, SNC	9:15-9:45 a.m.
V.	NRC Staff Presentation on the Interim Safety Evaluation Report (SER) on the Hatch LRA	W. Burton	9:45-10:30 a.m.

NOTE: Presentation time should not exceed 50 percent of the total time allotted for specific item. The remaining 50 percent of the time is reserved for discussion.

Number of copies of the presentation materials to be provided to the ACRS - 35.

ACRS LICENSE RENEWAL SUBCOMMITTEE

PLANT HATCH LICENSE RENEWAL APPLICATION

APRIL 5, 2001

WILLIAM BURTON
PROJECT MANAGER
NRR

OVERVIEW

BACKGROUND

APPLICATION SUBMITTED BY LETTER DATED FEBRUARY 29, 2000

BOILING WATER REACTOR. 2 UNITS

PLANT LOCATED ON ALTAMAHA RIVER IN APPLING COUNTY, GEORGIA. APPROXIMATELY 11 MILES NORTH OF BAXLEY, GEORGIA

UNIT 1: CURRENT LICENSE EXPIRES AUGUST 6, 2014. REQUESTS RENEWAL THROUGH AUGUST 6, 2034

UNIT 2: CURRENT LICENSE EXPIRES JUNE 13, 2018. REQUESTS RENEWAL THROUGH JUNE 13, 2038

CURRENT REVIEW STATUS

OVERVIEW

COMPARISON TO PREVIOUS LICENSE RENEWAL APPLICANTS

FIRST BWR

FIRST TO USE BOILING WATER REACTOR VESSEL AND INTERNALS PROJECT (BWRVIP) REPORTS

FIRST TO USE FUNCTIONAL APPROACH VS SYSTEM APPROACH IN SCOPING PROCESS

FIRST TO APPLY AGING MANAGEMENT PROGRAM ATTRIBUTES TO DEMONSTRATE ADEQUACY OF AGING MANAGEMENT VS APPLYING ATTRIBUTES TO AGING MANAGEMENT PROGRAMS

OPEN ITEMS

18 OPEN ITEMS IDENTIFIED IN SER

OPEN - 13

UNDER APPEAL - 4

CONFIRMATORY - 5

STATUS OF APPEAL ISSUES

APPEAL MEETING HELD BETWEEN STAFF AND APPLICANT ON MARCH 29, 2001

ISSUE #1 - SHOULD THE DRAWDOWN TEST REQUIRED BY TECHNICAL SPECIFICATIONS BE CREDITED AS AN AMP TO CONFIRM MAINTENANCE OF REACTOR BUILDING IN-LEAKAGE LIMITS?

ISSUE #2 - SHOULD PIPING THAT IS CATEGORIZED AS SEISMIC II/I AT PLANT HATCH BE INCLUDED WITHIN THE SCOPE OF LICENSE RENEWAL?

ISSUE #3 - SHOULD HIGH-ENERGY LINE BREAK POSTULATIONS THAT ARE BASED ON FATIGUE USAGE FACTOR BE CONSIDERED AS A TLAA?

ISSUE #4 - SHOULD THE HOUSINGS FOR FANS, DAMPERS, AND HEATING AND COOLING COILS THAT ARE WITHIN THE SCOPE OF LICENSE RENEWAL BE CONSIDERED PASSIVE COMPONENTS AUBJECT TO AN AGING MANAGEMENT REVIEW?

REGULATORY PERSPECTIVE
OF BWR VESSEL & INTERNALS PROGRAM
GENERIC AGING MANAGEMENT PROGRAM

April 5, 2001

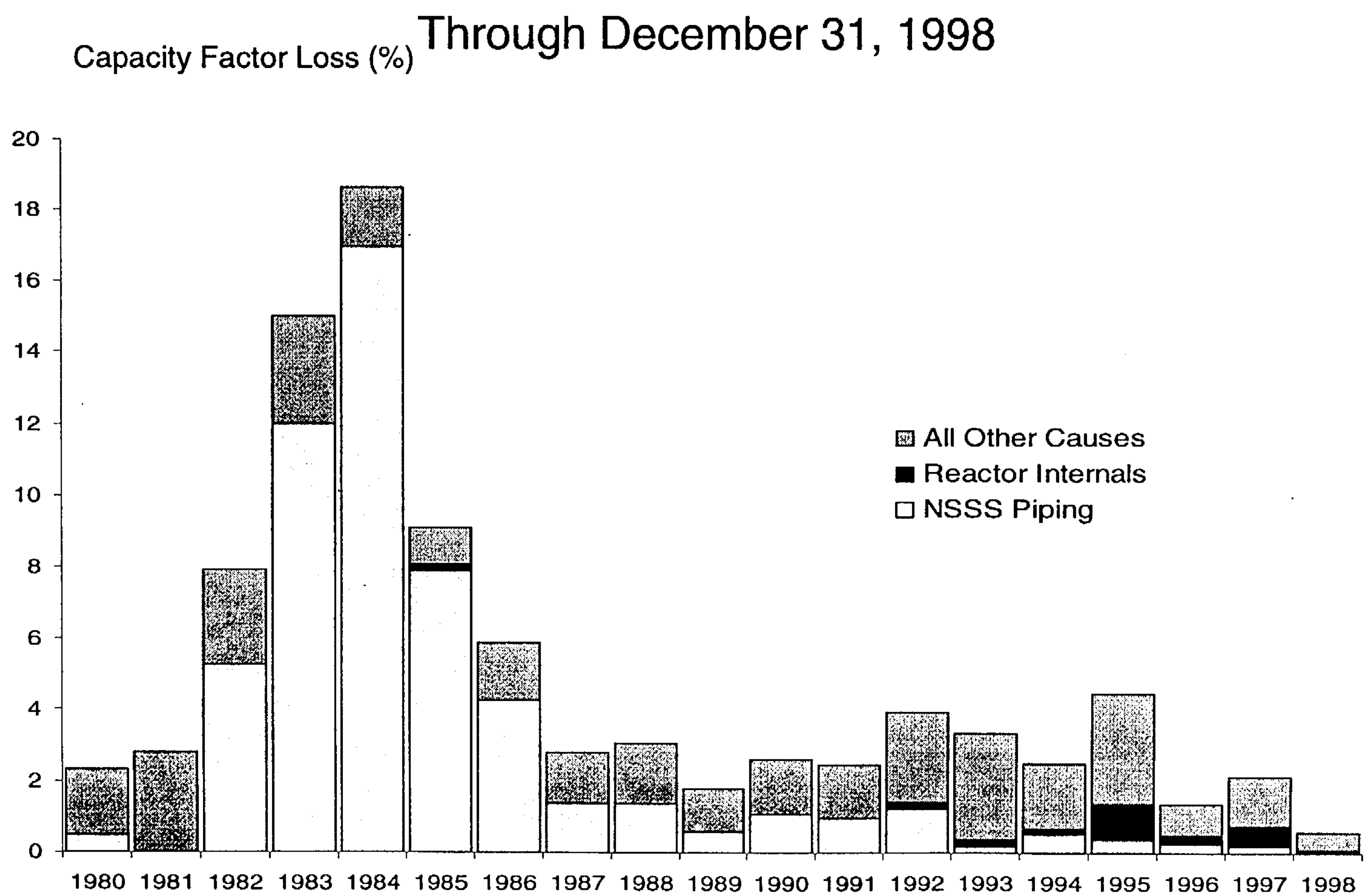
C. E. Carpenter, Jr.
Materials & Chemical Engineering Branch
Office of Nuclear Reactor Regulation

OVERVIEW OF BWRVIP PROGRAM

- BWRVIP is a Voluntary Industry Initiative
  - Began in 1994 to Address Core Shroud Cracking Issues
  - Now Addresses All BWR Internal Components, Reactor Vessel, and Class I Piping Material Condition Issues
  - Guidance Covers Current Operating Term and Extended Operating Period

- BWRVIP Proactively Addressing Aging Degradation Issues That are Beyond Regulatory Requirements
  - BWRVIP Identifying or Developing Generic Cost Effective Strategies Appropriate for Plant Specific Needs
  - Industry's Regulatory Interface for BWR Material Issues
  - Industry's Material Issues Information Clearinghouse

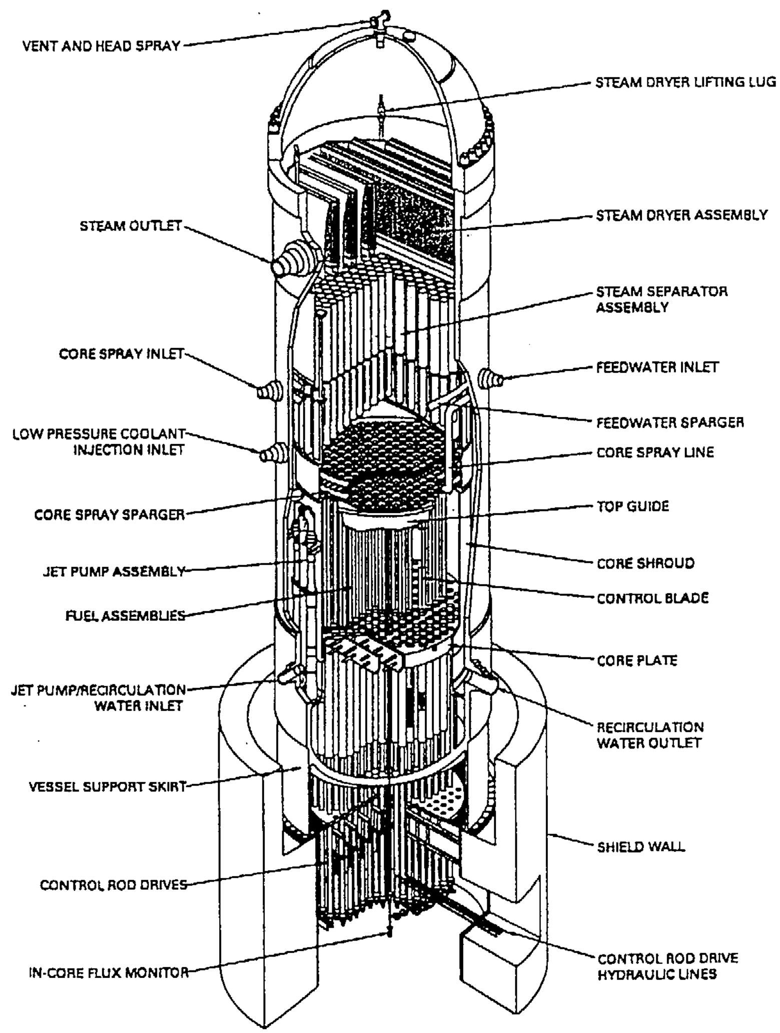
Capacity Factor Losses in BWRs



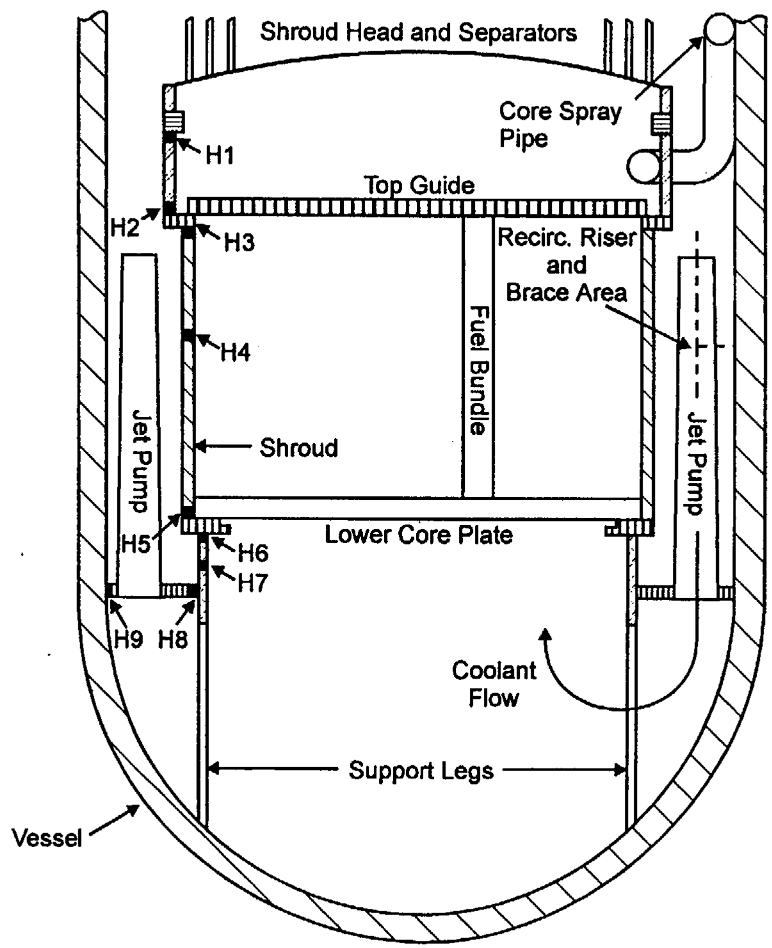
EPRI

BWRVIP

Typical Non-BWR/2 Reactor Assembly



Configuration



BWRVIP U.S. MEMBER UTILITIES

- Browns Ferry
- Brunswick
- Columbia (WNP-2)
- Clinton
- Cooper
- Dresden
- Duane Arnold
- Fermi
- FitzPatrick
- Grand Gulf
- Hatch
- Hope Creek
- LaSalle
- Limerick
- Monticello
- Nine Mile Point
- Oyster Creek
- Peach Bottom
- Perry
- Pilgrim
- Quad Cities
- River Bend
- Susquehanna
- Vermont Yankee

BWRVIP FOREIGN MEMBER UTILITIES

- Chubu Electric Power Company
- Chugoku Electric Power Company
- Comision Federal de Electricidad
- Forsmark Kraftgrupp AB
- Iderdrola Generation
- Japan Atomic Power Company
- OKG Aktiebolag
- Tohoku Electric Power Company
- Tokyo Electric Power Company
- Taiwan Power Company

BWRVIP REPORTS

- BWRVIP Scope Includes BWR Vessel, All Safety-Related Internal Components and Class I Piping
  - Core Shroud
  - Shroud Supports
  - Core Spray Internals
  - Jet Pump Assembly
  - Top Guide
  - Core Plate
  - Lower Plenum Components
  - Vessel ID Brackets
  - Standby Liquid Control
  - LPCI Couplings
  - Instrument Penetrations
  - RPV

- Guidelines Include
  - Inspection & Flaw Evaluation Methodology
  - Repair Design Criteria
  - Mitigation Guidance

BWRVIP REPORTS

- Inspection and Flaw Evaluation (I&E) Guidelines
  - BWRVIP-18, Core Spray Internals
  - BWRVIP-25, Core Plate
  - BWRVIP-26, Top Guide
  - BWRVIP-27, Standby Liquid Control System / Core Plate ΔP
  - BWRVIP-38, Shroud Support
  - BWRVIP-41, BWR Jet Pump Assembly
  - BWRVIP-42, BWR LPCI Coupling
  - BWRVIP-47, BWR Lower Plenum
  - BWRVIP-48, Vessel ID Attachment Weld
  - BWRVIP-49, Instrument Penetration
  - BWRVIP-74, BWR Reactor Pressure Vessel
  - BWRVIP-76, BWR Core Shroud

    → Combines BWRVIP-01, -07 and -63

BWRVIP REPORTS

- Repair / Replacement Design Criteria
  - BWRVIP-16, Internal Core Spray Piping & Sparger Replacement
  - BWRVIP-19, Internal Core Spray Piping and Sparger Repair
  - BWRVIP-34, Technical Basis for Circumferential Weld Overlay Repair of Vessel Internal Core Spray Piping
  - BWRVIP-44, Underwater Weld Repair of Nickel Alloy RPV Internals
  - BWRVIP-50, Top Guide / Core Plate
  - BWRVIP-51, Jet Pump
  - BWRVIP-52, Shroud Support and Vessel Bracket
  - BWRVIP-53, Standby Liquid Control Line
  - BWRVIP-55, Lower Plenum
  - BWRVIP-56, LPCI Coupling
  - BWRVIP-57, Instrument Penetrations
  - BWRVIP-58, CRD Internal Access Weld

BWRVIP REPORTS

- Crack Growth & Mitigation Reports
  - BWRVIP-14, Evaluation of Crack Growth in BWR Stainless Steel RPV Internals
  - BWRVIP-59, Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals
  - BWRVIP-60, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals
  - BWRVIP-62, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection
  - BWRVIP-80, Evaluation of Crack Growth in BWR Shroud Vertical Welds

BWRVIP REPORTS

- Other Reports
  - BWRVIP-03, RPV Internals Examination Guidelines
  - BWRVIP-06, Safety Assessment of BWR Reactor Internals
    → Supported by Deterministic Assessment of Consequences

- Safety Assessment Identified Components Necessary for Safe Operation Shutdown
  - Maintain Coolable Geometry
  - Maintain Rod Insertion Times
  - Maintain Reactivity Control
  - Assure Core Cooling
  - Assure Instrument Availability

BWRVIP PROGRAM

- General Format of I&E Guidelines
  - Description of Component, Inspection History and Susceptibilities
  - Failure Consequences
  - Inspection Requirements (Scope and Frequencies)
  - Flaw Evaluation Methodologies
  - Reporting Requirements

- Program Assures
  - Inspections Performed Correctly and On Time by Qualified Personnel
  - Inspection Results and Flaws Properly Evaluated and Dispositioned
  - Repairs Meet Approved BWRVIP Criteria or Applicable Codes

BWRVIP CONCLUSIONS

- BWRVIP Program is Broad in Scope
- BWRVIP Program Includes Appropriate Inspections, Evaluation Methodologies, Repair Criteria and Mitigation Methods to Assure BWR Internals Integrity
- Use of BWRVIP Program During License Renewal Period Provides Adequate Aging Management Program

STAFF'S REVIEW OF BWRVIP REPORTS

- Staff Has Completed Review of Almost All BWRVIP Reports
  - Staff Has Concluded that Implementation of BWRVIP Guidelines, as Modified to Address Staff Comments, Will Provide an Acceptable Level of Quality for Inspection and Flaw Evaluation of Subject Safety-Related Components
  - Independent RES Review (NUREG/CR-6677) Found That Comprehensive Inspection Programs Like BWRVIP Significantly Reduces Core Damage Frequency

STAFF'S REVIEW OF BWRVIP REPORTS

- Staff Completing Review of BWRVIP LR Appendices and Has Found That:
  - Referencing BWRVIP AMPs and Completing Action Items Will Provide Reasonable Assurance that Applicant Will Adequately Manage Aging Effects During Extended Operation Period
  - Generic AMPs Usage Will Significantly Reduce Staff Review of LR Applications

AP1000 Pre-Application Review
Advisory Committee on Reactor Safeguards

Jerry N. Wilson, PE
Future Licensing Organization
Office of Nuclear Reactor Regulation
April 5, 2001

Purpose of Pre-application Review

- Determine the scope and cost of a design certification review
- Obtain agreement on how AP600 can be used as a basis for the AP1000 design certification application

- Phase 1 complete - NRC letter of July 27, 2000 identified 6 issues that could have a significant impact on the cost and schedule of a design certification review and estimated effort for Phase 2
- Phase 1 results discussed with ACRS on August 29, 2000
- Phase 2 begun - Westinghouse requested the NRC to proceed with a portion of the Phase 2 review by letter dated August 28, 2000
- Phase 3 - Westinghouse submits application in 2002?

Phase 2 Review Issues

- Applicability of AP600 Test Program to the AP1000 design

Plant Description and Analysis Report - December 2000
PIRT and Scaling Assessment Report - March 2001

- Applicability of AP600 Analysis Codes to AP1000 design

AP1000 Code Applicability Report - April 2001

- Acceptability of using Design Acceptance Criteria in selected areas

Seismic and Structural Design Activities - January 2001

- Applicability of the exemptions granted to the AP600 design

Phase 2 Review Schedule

- Phase 2 review duration estimated at ~ 9 months
- Waiting for the analysis codes to "officially" start Phase 2
- Staff will prepare a NUREG report on the Phase 2 results
- Staff will request an ACRS letter on Phase 2 in ~ 6 months
- Staff will prepare a SECY paper on Phase 2
- Letter to Westinghouse that provides results of Phase 2 review

ACRS Meeting

Plant Hatch Units 1 & 2
License Renewal Application

Ray Baker - Hatch License Renewal Project Manager
April 5, 2001

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PLANT HATCH LICENSE RENEWAL APPLICATION DISCUSSION TOPICS

- **Plant Hatch Operating Experience**
- **Plant Hatch License Renewal Programs**
  - Existing Programs
  - Enhanced Programs
  - New Programs

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PLANT HATCH LICENSE RENEWAL PROGRAMS

EXISTING PROGRAMS

- ◆Reactor Water Chemistry Control
- ◆CCW Chemistry Control
- ◆Diesel Fuel Oil Testing
- ◆*PSW & RHRSW Chemistry Control*
- ◆Spent Fuel Pool Chemistry Control
- ◆Demineralized Water and CST Chemistry Control
- ◆Suppression Pool Chemistry Control
- ◆Inservice Inspection Program
- ◆Overhead Crane & Refueling Platform Inspections
- ◆Torque Activities
- ◆Component Cyclic or Transient Limit Program
- ◆*PSW & RHRSW Inspection Program*
- ◆Primary Containment Leakage Rate Testing Program
- ◆BWRVIP
- ◆RPV Monitoring Program
- ◆Wetted Cable Activities

BLACK = Administrative Changes
BLUE = Minor Technical Changes

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PLANT HATCH LICENSE RENEWAL PROGRAMS

ENHANCED PROGRAMS

- ◆Fire Protection Activities
- ◆FAC Program
- ◆*Protective Coatings Program*
- ◆*Equipment and Piping Insulation Monitoring Program*
- ◆Structural Monitoring Program

BLACK = ENHANCED SCOPE
BLUE = TECHNICAL ADDITIONS

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PLANT HATCH LICENSE RENEWAL PROGRAMS

NEW PROGRAMS

- ◆Galvanic Susceptibility Inspection
- ◆Treated Water Systems Piping Inspection
- ◆Gas Systems Component Inspection
- ◆CST Inspection
- ◆*Passive Component Inspection Activities*
- ◆*RHR Heat Exchanger Augmented Inspection and Testing Program*
- ◆*Torus Submerged Components Inspection Program*
- ◆Non-EQ Cable Management Program

BLACK = NEW

BLUE = SUBSTANTIALLY REVISED AND REPACKAGED

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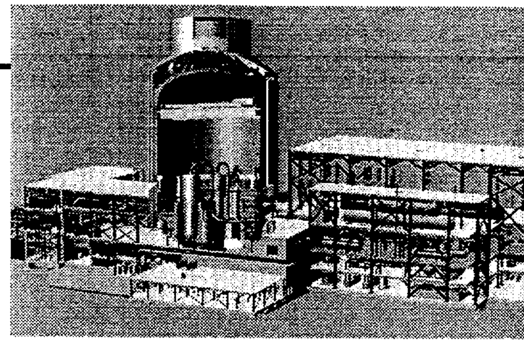


AP1000 Pre-Certification Review

Presentation to the

Advisory Committee on Reactor Safeguards

April 5, 2001

Agenda

- 2:50 Introduction — G. Wallis
- 2:55 AP1000 Pre-Cert Review Overview — J. Wilson
- 3:05 Introductory Remarks / NSSS Overview — M. Corletti
- 3:15 AP1000 Passive Safety Systems Design and Analysis — T. Schulz
- 3:35 Review of AP1000 PIRT and Scaling Approach — W. Brown
- 3:55 Approach to the Application of Analysis Codes — J. Gresham
- 4:00 Design Acceptance Criteria — R. Orr
- 4:10 Discussion

AP1000 Introduction / NSSS Overview

Mike Corletti
AP600 Engineering

Purpose of Today's Meeting

- Informational Meeting
  - Introduce ACRS to AP1000
  - Explain the objectives of the AP1000 Pre-Certification Review
  - Review our proposed approach to resolution of key issues:
- Feedback on our approach
- Expectations for future meetings

AP600 Major Uprate - Objectives

- Increase Plant Power Rating to Reduce Cost
  - Obtain a capital cost that can compete in U.S. market $900-1000/KWe for nth twin plant

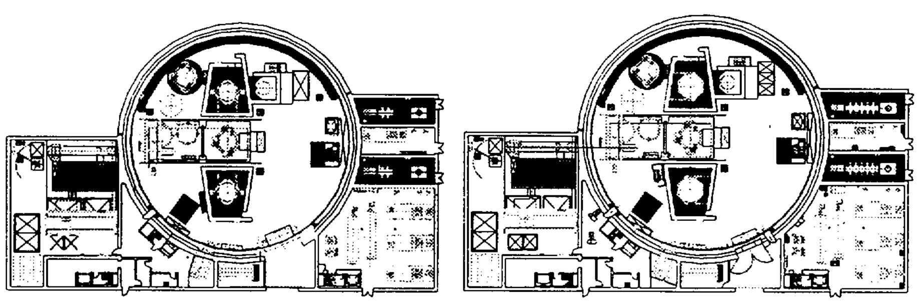
- Retain AP600 Objectives and Design Detail
  - Increase the capability/capacity within "space constraints" of AP600
  - Retain credibility of "proven components"
  - Retain the basis for the cost estimate, construction schedule and modularization scheme

- Retain AP600 Licensing Basis
  - Meet regulatory requirements for Advanced Passive Plants
  - Accept AP600 policy issues

AP1000 General Arrangement

Plan at Elevation 135'

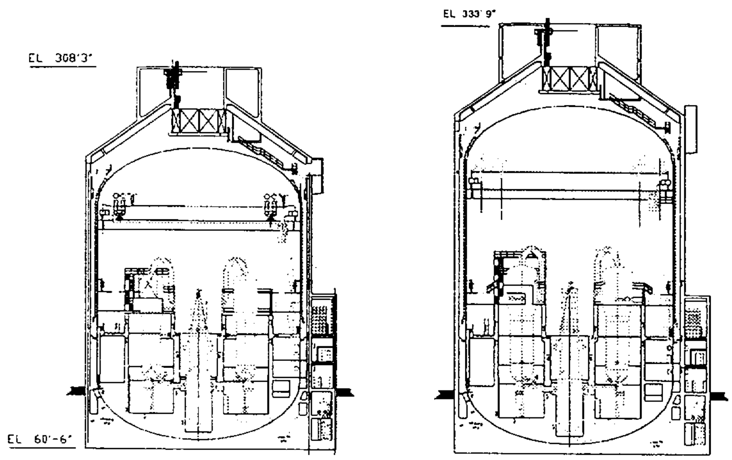
AP600 AP1000



AP1000 General Arrangement

Containment Section View

AP600 AP1000



AP1000 Pre-Certification Objectives

- Obtain agreement on how AP600 Certification can be used as a basis for AP1000 Design Certification
  - Improve efficiency of licensing process
  - Identify path for leveraging AP600 Certification to AP1000

- How do we plan on meeting this objective?
  - 3-Phase Approach Suggested by NRC
    - Phase 1 - Identified 6 issues to evaluate in Pre-certification review
      - Issues that potentially have a large impact on design certification licensing cost and schedule
        - ACRS provided insights and guidance
    - Phase 2 - Pre-certification review of the issues identified
      - Two items deferred until Design Certification due to W budget contraints
        - Portions of AP600 SSAR retained for AP1000 - 80%
        - Application of AP600 PRA to AP1000
    - Phase 3 - Design Certification

Phase 2 Review - Status of Issues

1. Sufficiency of AP600 Test Program to meet 10 CFR Part 52 requirements for AP1000
   - Plant Description and Analysis Report — December 2000
   - PIRT and Scaling Assessment Report — March 2001

2. Applicability of NRC-approved AP600 analysis codes for AP1000 Design Certification
   - Code Applicability Report — April 2001

3. Acceptability of using Design Acceptance Criteria in selected areas
   - Seismic and Structural Design Activities — January 2001

4. Applicability of Exemptions granted to AP600

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Comparison of Selected Parameters

PARAMETER	AP600	AP1000
Net Electric Output, MWe	610	1090
Reactor Power, MWt	1933	3400
Hot Leg Temperature, °F	600	615
Number of Fuel Assemblies	145	157
Type of Fuel Assembly	17x17	17x17
Active Fuel Length, ft	12	14
Linear Heat Rating, kw/ft	4.10	5.71
Control Rods / Gray Rods	45 / 16	53 / 16
R/V I.D., inches	157	157
Steam Generator Surface Area, ft^2	75,000	125,000
Reactor Coolant Pump Flow, gpm	51,000	75,000
Pressurizer Volume, ft^3	1600	2100

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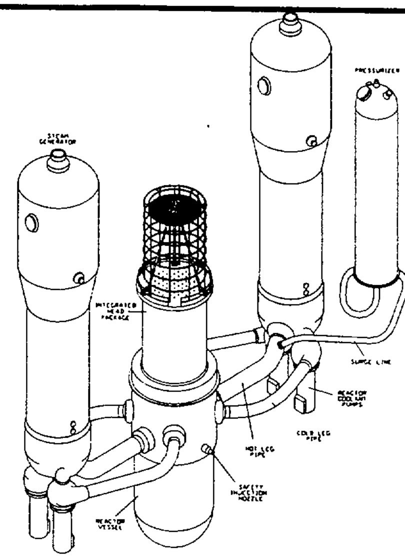
AP1000 Reactor Coolant System

- Proven Reactor Design
  - Based on W 14-ft Core Designs
    - Doel 4; Tihange 3; South Texas
- Δ125 Steam Generators
  - Based on W/CE designs
    - ANO Replacement SG
- Reactor Coolant Pump
  - Based on AP600
    - Increased capacity
      - Variable speed controller
      - Increased inertia
- Simplified Main Loop
  - Same as AP600
- Pressurizer
  - 50% larger than operating units



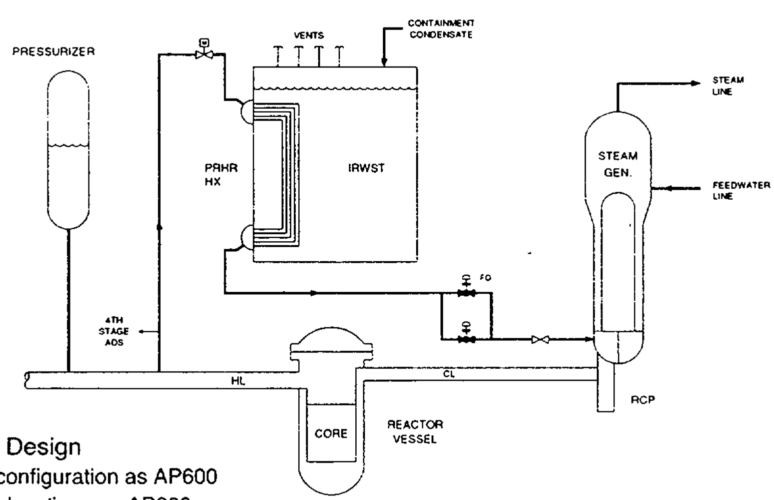
AP1000 Passive Safety Systems

Terry Schulz
Advisory Engineer

AP1000 Passive Safety Systems Design

- **Use AP600 System Configuration / Arrangement**
- **Increase Capacities to Maintain Adequate Safety Margins**
    - Consider both deterministic and probabilistic criteria
    - Provide margin for uncertainty in AP600 tests / computer codes
- **Iterative Design / Sizing Process**
    - Hand calculation used to estimate needed capacity increases
        - First principle hand calculations, independent of test/analysis
        - Separate effects, window in time, based on AP600 experience
    - Plant computer code T&H analysis used to confirm / adjust capacities
        - AP600 SSAR computer codes with same assumptions
            - Not final Chapter 15 safety analysis
        - Integrated effects, transient, limiting events
    - Consider plant impacts, especially building layout impacts

Passive Decay Heat Removal



- PRHR HX Design
    - Same configuration as AP600
    - Same elevations as AP600
    - Larger pipe sizes (14 vs 10")
    - Increased HX surface (more / longer horizontal tubes)

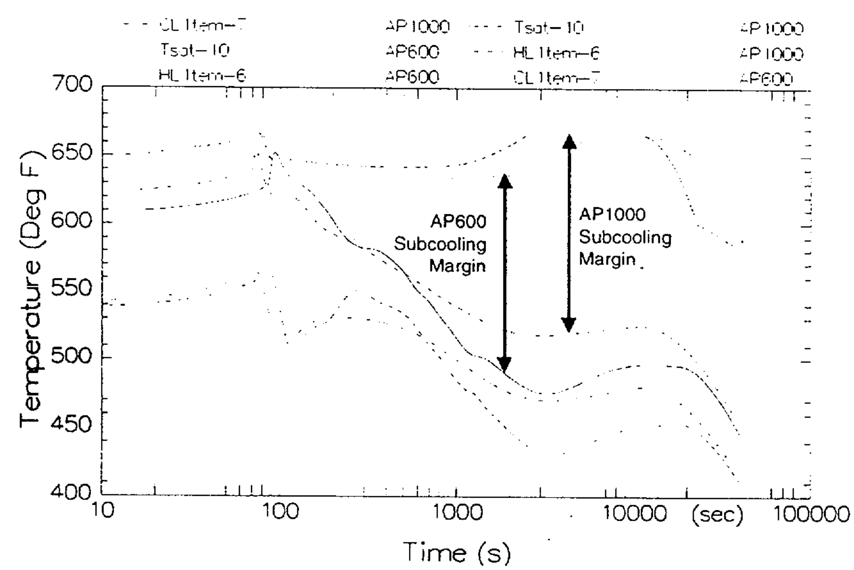
PRHR Margin Assessment

	AP600 (1)	AP1000 (1)
PRHR HX Surface Area	100%	122%
PRHR Flow Path Resistance	100%	33%
Calculated PRHR Heat Transfer (Nat Circ)		
, Heat transfer	>>> 100% <<<	>>> 172% <<<
, Time to match decay heat (min.)	38	44
SG Secondary Side Water		
, Initial water mass per MW	100%	136%
, Final water mass per MW	>>> 100% <<<	>>> 212% <<<

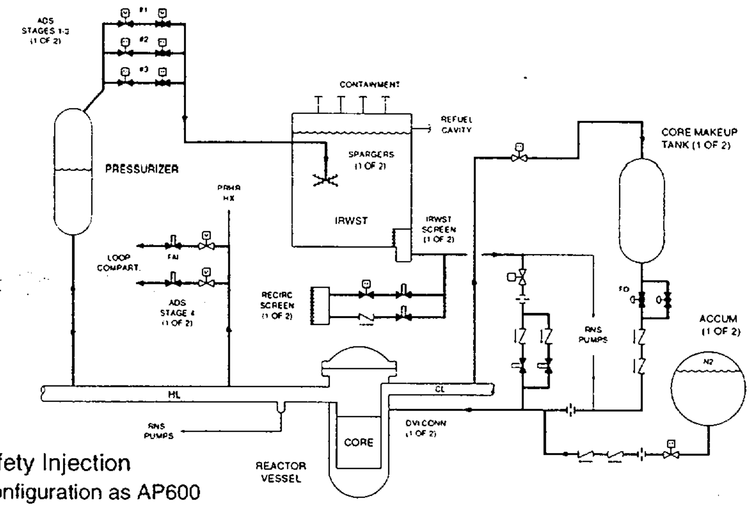
(1) Based on hand calculations.

- **AP1000 PRHR HX Expected to Provide Increased Margin**
  - PRHR HX heat transfer capacity increased almost by core power ratio (176%)
  - SG secondary mass increased greater than core power ratio

Feedline Rupture - Comparison



AP1000 Passive Safety Injection



- Passive Safety Injection
  - Same configuration as AP600
  - Same elevations as AP600
  - Larger CMT and CMT flow tuning orifice
  - Larger IRWST, Recirc, ADS 4 pipe sizes

Passive Safety Injection Margins

	AP600	AP1000
Accumulator – Large LOCA Reflood PCT (F)	1644	~1940
CMT flow capacity vs required flow (Flow required to remove decay and sensible heat at time of accumulator empty in DVI LOCA)	138%	129%
ADS stage 1,2,3 flow capacity vs AP600	100%	100%
ADS stage 4 flow capacity (2) vs AP600	100%	189%
IRWST injection flow capacity (2) vs AP600	100%	184%
Containment recirc flow capacity (2) vs AP600	100%	213%

(1) These margin assessments were performed using hand calculations.
(2) These flow capabilities were evaluated at limiting post accident plant conditions.

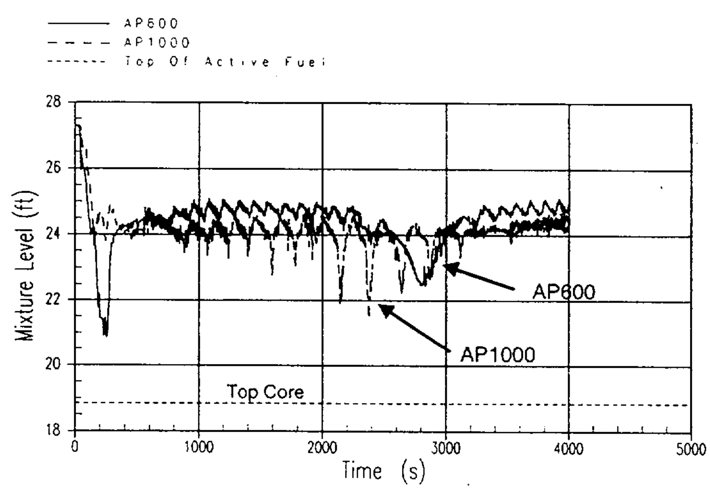
- **AP1000 Passive Safety Injection Expected to Provide Adequate Margin**

Passive Safety Injection Margins

- Accumulator
  - Same flow capability, tank constrained by concrete walls/floors
  - Large LOCA should have similar / larger margin vs operating plants
- CMT
  - Tank volume & flow capacity increased 25% (same pipe size)
  - Maintains injection duration, helps IRWST / ADS 4 sizing
- ADS
  - Stages 1,2,3 - adequate for higher pressure operation
    - Not important for IRWST cut-in or long term recirc
  - Stage 4 - Significant increase in flow capability, larger pipe sizes
    - Important for IRWST cut-in and long term recirculation
- IRWST Injection
  - Significant increase in flow capability, larger pipe sizes
- Containment Recirculation
  - Significant increase in flow capability, larger pipe sizes
  - RNS changed to take initial suction from water supply outside cont.

DVI LOCA Comparsion

Core/Upper Plenum Mixture Level

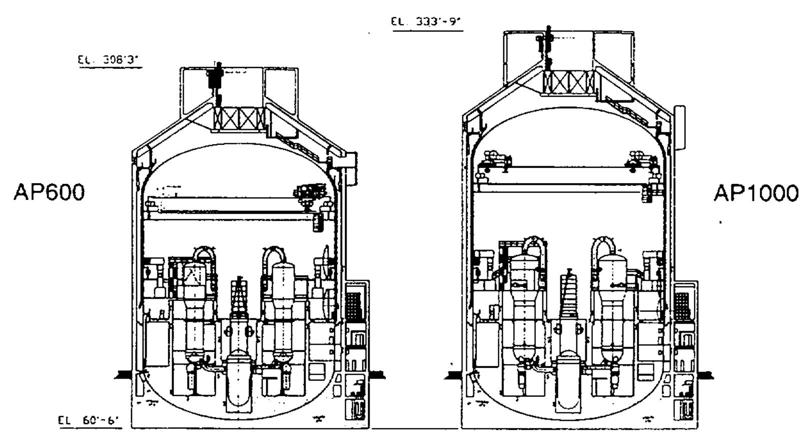


Expected AP1000 Safety Margins

	Typical Plant	AP600	AP1000
Loss Flow Margin to DNBR Limit	~ 1 – 5%	15.8%	13.6% (1)
Feedline Break Subcooling Margin	>0°F	~170°F	~140°F (1)
SG Tube Rupture	Operator actions required in 10 min	Operator actions ***NOT*** required	Same as AP600 (1)
Small LOCA	3" LOCA core uncovers PCT ~1500 °F	≤ 8" LOCA ***NO*** core uncovery	Same as AP600 (1)
Large LOCA PCT (with uncertainty)	2000 – 2200°F	1644°F	~1940°F

(1) Based on preliminary AP1000 T&H analysis using AP600 SSAR computer codes.

AP1000 Containment Comparison

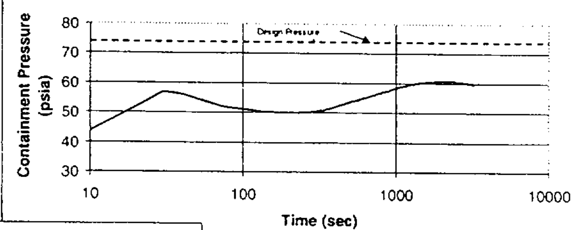


	AP600	AP1000
Total Free Volume	100%	122%
Design Pressure, psig	45	59
Shell Thickness	1 5/8"	1 3/4"
Material	A537 Class 2	SA738 Grade B
PCS Water Drain Vol (72 hr)	100%	162%

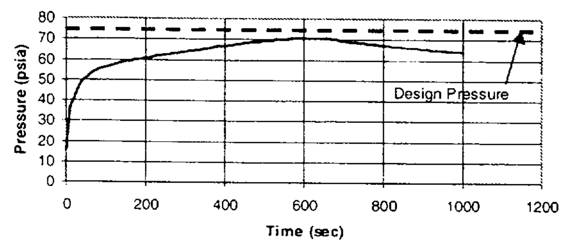
Containment Analysis Results

- **AP1000 Containment Expected to Provide Increased Margins**
  - Similar response to AP600
  - Large LOCA has large margins
    - With more realistic SG energy input

AP1000 DECL LOCA Containment Pressure Response



Main Steam Line Break Pressure Response



- **Main steam line break is limiting**
  - Not sensitive to passive containment cooling performance

AP1000 PIRT and Scaling Assessment

William Brown
LOCA Integrated Services

Main Goal and Steps of PIRT/Scaling Assessment

- Main goal of PIRT/Scaling assessment:
- Determine extent to which AP600 experimental test database is applicable to AP1000 to support safety analysis code validation in accordance with 10 CFR part 52.

- Main steps in PIRT/Scaling assessment:
- First, AP600 PIRTs reviewed by several experts for application to AP1000.
- Then, scaling of most important phenomena (high-ranked) obtained from PIRT review assessed relative to AP1000.

PIRT Reviewers/Summary of Important Changes for AP1000

- PIRT reviewers included following experts:
  - Dr. S. M. Bajorek, Kansas State University
  - Dr. S. G. Bankoff, Northwestern University
  - Dr. L. E. Hochreiter, Penn State University
  - Dr. T. K. Larson, INEEL
  - Dr. P. F. Peterson, University of California
  - Mr. G. E. Wilson, INEEL

- Summary of important PIRT changes for AP1000:
- LBLOCA
  - Core entrainment/de-entrainment increased from Medium to High
- SBLOCA including long term cooling
  - Entrainment increased to High for IRWST/sump injection.
  - ADS-4 two-phase pressure drop increased to High for IRWST/sump injection.
- Containment SLB/DE CL LOCA and Non-LOCA
  - No important changes.

Summary of Important Phenomena Addressed in Scaling Analysis

- Top-Down Scaling
  - Reactor vessel inventory
  - Core exit quality
  - RCS pressure
  - Core decay heat
  - ADS flow
  - ADS-4 two-phase pressure drop
  - CMT/IRWST injection
  - Sump injection
  - Natural circulation-PRHR
  - Pressurizer level
  - Containment pressure
  - Break mass/energy into containment
  - Containment volume/gas compliance
  - Heat/mass transfer to internal heat sinks
- Bottom-Up Scaling
  - Entrainment in HL/ADS paths
  - Hot leg/cold leg flow pattern
  - Surge line pressure drop
  - Phase separation at CL-CMT balance line tee
  - Core exit void fraction
  - Condensation on inside containment surfaces
  - Evaporation on outside surface containment shell
  - Water film stability/coverage on outside shell surface
  - Circulation/stratification inside containment

Scope of Scaling Assessment

- Scaling assessment focuses on high-ranked phenomena for passive plants:
  - Small Break LOCA - core cooling/vessel inventory.
  - Steam Line Break - containment pressure.
- Phenomena found in conventional PWR plants for which test databases already exist need not be scaled for AP1000 such as:
  - LBLOCA phenomena.
  - Blowdown & S.G. circulation phenomena of SBLOCA.
  - Non-LOCA (except for CMT/PRHR phenomena).
- Scaling assessment of low-ranked/medium-ranked phenomena in AP600 scaling effort sufficient for AP1000.

Basis and Approach for AP1000 Scaling Assessment

- AP600 scaling analyses serve as basis for AP1000.
- AP1000 scaling assessment leverages results, insights, lessons learned from AP600.
  - Processes not important or minor are not scaled.
  - Simplified models/equations used to highlight important features.
- Emphasize features different or scaled up from AP600 (core power, volume, ADS4 vent area etc).
- Scaling assessment accomplished via examination and comparison of range of operating conditions and geometric similarity between AP1000 and test facility. AP600 scaling analysis usually sufficient.
  - This is typically sufficient for separate effects tests.
- Where comparison between AP1000 and test facility not easily accomplished from examination described above, then assessment supplemented with scaling analysis.
  - This is typically needed for integral effects tests.

AP600 Test Data Sources Included in Scaling Assessment

	Assessment	Scaling analysis
• Integral Effects Tests (IET)		
• SPES-2	√	√
• OSU	√	√
• ROSA-AP600	√	
• LST	√	√
• Separate Effects Tests (SET)		
• ADS (1-3)	√	
• CMT	√	
• PRHR	√	
• DNB	√	
• U.of Wisconsin Condensation	√	√
• Heated flat plate	√	√
• Water distribution	√	√
• Wind tunnel/bench experiment	√	
• Air-flow path Δp	√	
• Water film formation	√	√

Major Results of Passive Core Cooling System Scaling Analysis

- Overall results similar to AP600.
- At least one IET facility can be identified for each phase of SBLOCA transient where important phenomena is acceptably scaled to AP1000 to provide database suitable for code validation:
  - SPES acceptable for high pressure phases of SBLOCA transient; distorted after ADS-4 flow transitions to subsonic.
  - OSU acceptable for low pressure phases of SBLOCA transient;distorted until ADS-4 is actuated.
- AP600 SETs acceptable for AP1000.
  - ADS test acceptable as ADS 1-3 valves/sparger same as AP600. Tested range of conditions covers AP1000.
  - CMT test covers range of conditions in AP1000.
  - PRHR test covers tested range of conditions in AP1000. Heat transfer correlation developed from test provides acceptable agreement with ROSA-AP600 results.

Major Results of Passive Containment Cooling Scaling Analysis

- As with AP600, LST is distorted for code validation of AP1000 pressure transient
  - AP600 used bounding analysis for pressure transient
  - AP1000 uses same approach
- LST acceptable as separate effect test data base for validation of steady state heat/mass transfer correlations for AP1000
- Key dimensionless scaling groups for heat/mass transfer and liquid film stability/coverage are acceptably scaled in SETs.
- CFD analysis demonstrates AP1000 and AP600 similarly mixed inside containment.

Overall Conclusion of AP1000 PIRT and Scaling Assessment

- AP1000 phenomena are similar to AP600
- AP600 tests are scaled adequately to the AP1000
  - Separate effects tests cover AP1000 ranges
  - At least one integral effects test facility can be used to cover each phase of AP1000 SBLOCA transient
    - Similar to AP600
- Analysis codes that are validated against AP600 test data are applicable to AP1000

AP600 test database is sufficient for code validation in accordance with requirements of 10 CFR Part 52

Computer Codes to be Used for AP1000 Design Certification

J. A. Gresham, Manager
LOCA Integrated Services

AP1000 Safety Analysis Approach

- Start With Computer Codes Approved for Passive Plant Analysis in AP600 Design Certification
- Confirm Adequacy for Analysis of AP1000 Design
- Address Potential Concerns Identified in AP600 Review
- Reach Consensus on Acceptability

Confirm Adequacy of Codes for AP1000 Design

- Identify important phenomena (via PIRTs) that must be addressed by code (Complete - AP1000 PIRT & Scaling Report)
- Identify correlations and models used in code to address important phenomena (Complete - AP600 Design Certification)
- Demonstrate that adequate test data base exists to support validation of correlations/models via scaling analyses (Complete - AP1000 PIRT & Scaling Report)
- Demonstrate that limitations identified in AP600 FSER are addressed for AP1000

Approach to Address Limitations Identified in AP600 Review

- Design Modification
- Additional Validation against Tests
- Evaluation of Margin
- Supplementary Analyses
- Code Enhancements

Contents of Code Applicability Report

- Important AP1000 phenomena and comparison to AP600 (PIRT)
- Code description
- Code acceptability for AP600 (FSER)
- Code limitations (FSER) and how each is addressed
- Applicability of Code to AP1000

AP1000 Approach to Design Acceptance Criteria

Richard Orr
Advisory Engineer

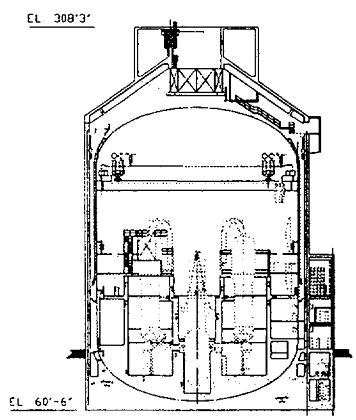
AP1000 Structural Configuration

- AP1000 structural configuration is similar to AP600
  - The AP1000 configuration and its differences from AP600 are described in AP1000 Plant Description and Analysis Report (WCAP-15612)
- Principal differences
  - Increase in height of containment vessel and shield building
  - Increase in PCS tank inventory
- Differences have been evaluated and can be accommodated in the structural design

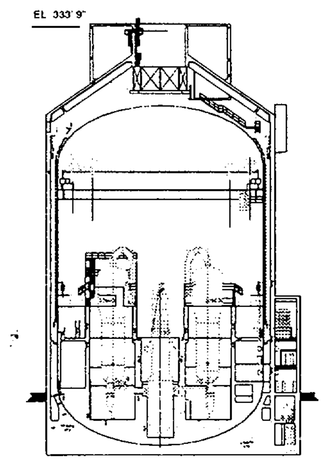
AP1000 General Arrangement

Containment Section View

AP600



AP1000



Summary of Seismic Responses

Maximum Absolute Nodal Acceleration, ZPA (g)						
	AP600			AP1000		
Elevation	N-S	E-W	VERT	N-S	E-W	VERT
Top of shield building	1.44	1.47	0.90	1.44	1.54	0.89
Top of containment vessel	0.94	1.21	1.49	0.96	1.03	1.42

Maximum Forces (x10^3 Kips)						
	AP600			AP1000		
Elevation	Axial	N-S Shear	E-W Shear	Axial	N-S Shear	E-W Shear
Aux. building - El. 100'	34.96	37.54	37.59	41.61	46.80	38.69
Containment vessel El. 100'	4.60	3.93	4.49	5.26	5.11	4.79

Maximum Moment (x10^3 K-ft)						
	AP600			AP1000		
Elevation	Torque	about N-S Axis	about E-W Axis	Torque	about N-S Axis	about E-W Axis
Aux. building - El. 100'	1396	4188	4045	1640	5564	6048
Containment vessel El. 100'	11	489	429	38	629	652

From WCAP-15614, Table B-1

AP1000 Seismic and Structural

- WCAP-15614 describes proposed approach for AP1000 Design Certification using Design Acceptance Criteria
- Design Acceptance Criteria are used on other certified designs for structural and piping design
- Design criteria and methodology in AP1000 DCD will be similar to AP600 DCD
- Structural configuration, seismic analysis for hard rock and containment vessel design will be provided in AP1000 DCD

AP1000 Detail Design

- Detail design and analysis will be completed by the Combined License applicant and audited by NRC staff during Combined License review prior to start of construction
- Final design and reconciliation is covered by ITAAC as used for AP600

Full

ACRS LICENSE RENEWAL ~~SUB~~COMMITTEE

PLANT HATCH LICENSE RENEWAL APPLICATION

APRIL 5, 2001

WILLIAM BURTON
PROJECT MANAGER
NRR

OVERVIEW

BACKGROUND

APPLICATION SUBMITTED BY LETTER DATED FEBRUARY 29, 2000

BOILING WATER REACTOR. 2 UNITS

PLANT LOCATED ON ALTAMAHA RIVER IN APPLING COUNTY, GEORGIA. APPROXIMATELY 11 MILES NORTH OF BAXLEY, GEORGIA

UNIT 1: CURRENT LICENSE EXPIRES AUGUST 6, 2014. REQUESTS RENEWAL THROUGH AUGUST 6, 2034

UNIT 2: CURRENT LICENSE EXPIRES JUNE 13, 2018. REQUESTS RENEWAL THROUGH JUNE 13, 2038

CURRENT REVIEW STATUS

OVERVIEW

COMPARISON TO PREVIOUS LICENSE RENEWAL APPLICANTS

FIRST BWR

FIRST TO USE BOILING WATER REACTOR VESSEL AND INTERNALS PROJECT (BWRVIP) REPORTS

FIRST TO USE FUNCTIONAL APPROACH VS SYSTEM APPROACH IN SCOPING PROCESS

FIRST TO APPLY AGING MANAGEMENT PROGRAM ATTRIBUTES TO DEMONSTRATE ADEQUACY OF AGING MANAGEMENT VS APPLYING ATTRIBUTES TO AGING MANAGEMENT PROGRAMS

OPEN ITEMS

18 OPEN ITEMS IDENTIFIED IN SER

OPEN - 13

UNDER APPEAL - 4

CONFIRMATORY - 5

STATUS OF APPEAL ISSUES

APPEAL MEETING HELD BETWEEN STAFF AND APPLICANT ON MARCH 29, 2001

ISSUE #1 - SHOULD THE DRAWDOWN TEST REQUIRED BY TECHNICAL SPECIFICATIONS BE CREDITED AS AN AMP TO CONFIRM MAINTENANCE OF REACTOR BUILDING IN-LEAKAGE LIMITS?

ISSUE #2 - SHOULD PIPING THAT IS CATEGORIZED AS SEISMIC II/I AT PLANT HATCH BE INCLUDED WITHIN THE SCOPE OF LICENSE RENEWAL?

ISSUE #3 - SHOULD HIGH-ENERGY LINE BREAK POSTULATIONS THAT ARE BASED ON FATIGUE USAGE FACTOR BE CONSIDERED AS A TLAA?

ISSUE #4 - SHOULD THE HOUSINGS FOR FANS, DAMPERS, AND HEATING AND COOLING COILS THAT ARE WITHIN THE SCOPE OF LICENSE RENEWAL BE CONSIDERED PASSIVE COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW?

UNITED STATES NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

April 5, 2001

IMPROVED LICENSE RENEWAL GUIDANCE DOCUMENTS

AGENDA

Topic	Presenter
Introduction	Sam Lee, NRR
Examples of Public Comments	Jerry Dozier, NRR
NEI Continued Dialog Items	Ed Kleeh, NRR
One-Time Inspections	Dave Solorio, NRR

IMPROVED LICENSE RENEWAL GUIDANCE DOCUMENTS

- Generic Aging Lessons Learned (GALL) report (NUREG-1801)
- Standard Review Plan for License Renewal (NUREG-1800)
- Regulatory Guide for License Renewal (RG 1.188)
- Nuclear Energy Institute (NEI) industry guidance 95-10, Rev. 3

TEAM EFFORT

- Office of Nuclear Reactor Regulation
- Office of Nuclear Regulatory Research
- Argonne National Laboratory
- Brookhaven National Laboratory

FUTURE ACTIVITIES

- Submit documents to Commission for approval (April 30, 2001)
- Continue dialog with NEI on 5 items
- Participate in NEI demonstration project to implement improved guidance documents

EXAMPLES OF PUBLIC COMMENTS

Resolved through repackaging, providing a minimum acceptable program, providing focus of concern, ensuring relevance, and completeness:

- **Added PWR reactor vessel internals program description to resolve the neutron fluence threshold issue for reactor vessel internals**
- **Boric Acid Corrosion programs (GL 88-05) are fully credited to manage the effects of boric acid corrosion**
- **PWSCC of pressurizer Alloy 600 penetrations is adequately managed by the chemistry and ISI programs; the Inconel 182 welds are a plant specific evaluation**
- **Removed insignificant aging effects such as wear/loss of material for the core support pads and the guide tube cards**
- **Added components such as the incore neutron flux monitoring tubes and CRD head flange bolting**

NEI CONTINUED DIALOG ITEMS

- IPE/IPEEE as source document to consider for scoping
- Operating experience with cracking of small-bore piping
- Management of loss of preload of reactor vessel internals bolting using the loose parts monitoring system
- Operating experience with cracking in bolting
- Inspections of fire protection systems

ONE-TIME INSPECTIONS

System	Calvert	Oconee	GALL
Reactor Vessel, Internals, and Reactor Coolant System	RCS-SBP, RVI, PZR	RCS-SBP, OTSG, PZR	RCS-SBP
Engineered Safety Features	CIG, SI, CS	LPI, RBS	ECCS
Auxiliary Systems	CC, SRW, SW, FP, CVCS, CA, EDG, RM, NSSS-Sampling, CR & DGB HVAC, PC-HVAC, Instru Lines, AB-HVAC	CC, SRW, LPSW/HPSW, CAS, DJW, CW, CCW, RCPMOC, DW, LWD, PS Systems: CD, DA, GA, SSFASW, SSFDW, SSFSL	CCCS, OCCS, FP, EDG, SFS, SFCC, SDC, DFO
Steam and Power Conversion	FW, MS, ES, N&H, AFW	TGCW, TSP, Cond PS Systems: ASW	FW, STS, ES, Cond, SGB, AFW

ONE-TIME INSPECTIONS

System	ANO	Hatch	GALL
Reactor Vessel, Internals, and Reactor Coolant System	RVI, PZR (htr bundles)	NBS, RRS	RCS-SBP
Engineered Safety Features	SH	SLC, RHR, CS, HPCI, RCIC, SGT, PCP&I, PLHR, PC	ECCS
Auxiliary Systems		CRD, CST, SAM, PSW, CC, EDG, HVAC, DFO, SW2	CCCS, OCCS, FP, EDG, SFS, SFCC, SDC, DFO
Steam and Power Conversion		EHC, MC&A	FW, STS, ES, Cond, SGB, AFW

AB-HVAC - Auxiliary Building Heating and Ventilation
AFW - Auxiliary Feedwater
ASW - Auxiliary Service Water
CA - Compressed Air
CAS - Chemical Addition
CC - Component Cooling
CCCW - Closed-Cycle Cooling Water
CCW - Condenser Circulating Water
CD - Carbon Dioxide system
CIG - Containment Isolation Group
Cond - Condenser or Condensate system
CR & DGB HVAC - Control Room and Diesel Generator Building HVAC
CRD - Control Rod Drive
CS - Containment Spray
CST - Condensate Storage Tank
CVCS - Chemical and Volume Control System
CW - Chilled Water
DA - Depressing Air system
DFO - Diesel Fuel Oil
DJW - Diesel Jacket Water
DW - Demineralized Water
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro-Hydraulic Control
ES - Extraction Steam
FP - Fire Protection
FW - Feedwater system
GA - Governor Air system
HPCI - High Pressure Coolant Injection
HPSW - High Pressure Service Water
HVAC - Heating and Ventilation
Instru Lines - Instrument Lines
LPI - Low Pressure Injection
LPSW - Low Pressure Service Water
LWD - Liquid Waste Disposal
MC&A - Main Condensor and Auxiliaries
NBS - Nuclear Boiler System
N&H - Nitrogen and Hydrogen system
OCCW - Open-Cycle Cooling Water
OTSG - Once Through Steam Generator lateral supports
PC - Primary Containment (penetrations)
PC-HVAC - Primary Containment HVAC
PCP&I - Primary Containment Purge and Inerting
PLHR - LOCA Hydrogen Removal
PSW - Plant Service Water
RBS - Reactor Building Spray
RCIC - Reactor Core Isolation Cooling
RCPOC - Reactor Coolant Pump Oil Collection
RCS-SB - Reactor Coolant System - small bore piping
RHR - Residual Heat Removal
RM - Radiation Monitoring
RRS - Reactor Recirculation System
RVI - Reactor Vessel Internals
SAM - Sampling System
SDC - Shutdown Cooling System (Older BWR)
SFCC - Spent Fuel Cooling and Cleanup
SFS - Spent Fuel Storage
SGB - Steam Generator Blowdown
SGT - Standby Gas Treatment
SLC - Standby Liquid Control
SRW - Service Water
SSFDW - Standby Shutdown Facility Drinking Water
SSFSL - SSF Sanitary Lift
SSFASW - SSF Auxiliary Service Water
STS - Steam Turbine System
SW - Salt Water
SW2 - Screen Wash
TGCW - Turbine Generator Cooling Water
TSP - Turbine Sump Pump

CONCLUSION

- ACRS endorsement is requested for issuing these final documents to begin implementation