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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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MEETING

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THURSDAY,

NOVEMBER 3, 2005

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The Committee met in Room T2B3 of the U.S. Nuclear Regulatory Commission, Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., Graham B. Wallis, Chair, presiding.

MEMBERS PRESENT:

GRAHAM B. WALLIS	ACRS Chairman
WILLIAM J. SHACK	ACRS Vice Chairman
JOHN D. SIEBER	ACRS Member-At-Large
MARIO V. BONACA	ACRS Member
RICHARD S. DENNING	ACRS Member
THOMAS S. KRESS	ACRS Member
DANA A. POWERS	ACRS Member
VICTOR H. RANSOM	ACRS Member

C O N T E N T S

P R O C E E D I N G S

(8:31 p.m.)

CHAIRPERSON WALLIS: The meeting will now come to order.

This is the first day of the 527th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the committee will consider the following: the final review of the license renewal application for the Point Beach Nuclear Plant, Units 1 and 2; the draft final generic letter 2005-xx, "Grid Reliability and the Impact on Plant Risk and the Operability of Off-site Power"; the economic simplified boiling water reactor design; a draft ACRS report to the Commission on the NRC safety research program; and the preparation of ACRS reports.

The meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the designated federal official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions. A transcript of portions of the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I'll remind members that during lunchtime today we are scheduled to interview two candidates for potential membership on the ACRS. I guess it's better to say two potential candidates for membership because I don't know what potential membership is.

I'll begin with some items of current interest. You'll note in the handout that Commissioner Lyons made a couple of speeches at the beginning of this handout items of interest.

On page 63, I'm happy to note that Jess Delgado, who you all know, was honored by the Hispanic Employee Program Advisory Committee. And you may find it useful to refer at a future date to the new NRR organization chart at the very back of this handout.

Without further ado, I'd like to move on to the first item, final review of the license renewal application for Point Beach, and I will invite my colleague, Mario Bonaca to lead us through it.

DR. BONACA: Thank you.

Good morning. This morning we are reviewing the final ACR for the license renewal application for Point Beach Nuclear Power Plant, Units

1 and 2. We review this matter also during our subcommittee meting of May 31st, and also during the 523rd meeting of June 1-3, 2005.

At the time we issued an interim report, and essentially the interim report pointed out that we didn't see any issues to do with the open items, et cetera, that would be a main issue at the time of our review. We, however, express concern regarding the current performance of Point Beach.

And the main concern was to do with two issues. One was the ability of the licensee to properly implement commitments at this time when they were responding to a number of regulatory challenges, you know, there in column 4 of the RFP.

The other concern, of course, was with the corrective action program, which is the main engine behind license renewal, which is the ability of identifying deficiencies and implement corrective actions.

We received answers from the staff regarding the plants for inspections, and I expect to hear about today. I think they start this year, and they will address these issues.

With that I will turn to the staff right now. I believe is Mr. Guillespe here? He will lead us in this presentation.

MR. GUILLESPE: Yeah, Mario, I think we're still wrestling with the same thing you had just mentioned, but we are doing everything possible to maintain kind of our dictum, if you would, that current performance is separate from license renewal, but the committee is also free to ask the questions, and we'll try to answer them as we can relative to current performance, and there's some from the region here ready to do that.

Well, with that, I'll turn it right over to Jim and he can go through this from the licensee.

Oh, okay. We haven't done the introductions.

MS. RODRIGUEZ: Right. Veronica Rodriguez, project manager for Point Beach.

MS. LOUGHEED: I'm Patricia Lougheed. I am the lead inspector for license renewal from Region 3.

MS. LAND: Yeah, and I just moved over to license renewal through the reorganization I guess you have heard about in NRR, and I'm now the Branch Chief for license renewal, the project management are.

DR. BONACA: Just let me specify before we get into the presentation, our recommendations in the interim letter really were for the staff and not for the licensee. We asked specifically for some commitments to augment the inspections of the cap, Corrective Action Program and of the commitments.

And now the response said that the staff would be performing inspection in accordance with IC-71003, which is a standard review, pre-liense renewal review that you perform for any licensee. So therefore, you'll have to explain a little bit to the committee how this commitment is responsive to our request for an amended inspection process.

MR. GUILLESPE: Okay. I think Pat's going to be ready to talk about that. When you look at the scheduling of the normal, every two-year PINR program, the sequencing comes so that there will be one and then there will be another one right before they enter the renewal period. And so I think we'll be able to discuss some of the scheduling aspects and what's going to be happening in the normal program as opposed to just what's specifically being done for renewal.

DR. BONACA: Okay. I just wanted to specify what the concern of the committee was, and we're trying to understand in which way the response to intercede is responsive to our concerns.

CHAIRPERSON WALLIS: Jim.

MR. KNORR: Very good. Thank you.

Good morning, gentlemen. My name is Jim Knorr. I am the project manager for the Point Beach license renewal project, and we're pleased to be here this morning, and answer any of your questions, but what I want to do is just go through a very quick presentation here giving a little bit of background about Point Beach and its application and the SER.

I have with me my team this morning, and these are the names of the guys who have worked very hard over the last five years to put the application together, answer any RAIs and respond to any questions that you might have today if I can't answer them.

Point Beach is a two loop Westinghouse PWR. We're owned by We Energies of Wisconsin Electric Corporation on the big board. We are operated and all of us work for Nuclear Management Company, LLC. We're located in Two Creeks, Wisconsin, about 90 miles or so northeast -- I should say north northeast -- of Milwaukee on the west shore of Lake Michigan.

Our architect-engineer was Bechtel Corp. Rated thermal power is 1,540 watts, megawatts thermal, although the license renewal application assumed a power up rate. Our rated output is at 538 at this point, and we're looking at that up rate, but not for a couple of years off.

We have four emergency diesel generators, any one of which can provide the emergency power for the station. We also have a combustion turbine on site, which is --

DR. BONACA: Excuse me. "For the station," you mean both units?

MR. KNORR: For both units, that's correct. With one diesel we can respond to an emergency, an accident, one, and bring the other one to safe shutdown.

The combustion turbine is there as a station blackout device. Also, it's a device that's used for fire protection, as well. It's needed for that.

Our heat sink is Lake Michigan. We have a once through cooling system. Our containment is a post tension, steel reinforced concrete containment with a steel liner, and at present we are in 18-month fuel cycles.

CHAIRPERSON WALLIS: Can I ask you about this containment?

MR. KNORR: Yes, sir.

CHAIRPERSON WALLIS: I'm a bit puzzled. I saw that you are allowing 50 percent thickness loss of the containment plate, and you had had some borated water corrosion.

I couldn't find out how much erosion had occurred. Have you had a 50 percent thickness loss or have you had a one percent thickness loss or what?

MR. KNORR: There are some examples where we did have some loss. I don't have the details. John, can you? Do you happen to know what the actual losses were, or Mark?

MR. ORTMAYER: Mark Ortmayer, NMC.

The 50 percent of all loss was due to the mechanical damage. As far as corrosion --

CHAIRPERSON WALLIS: It actually happened?

MR. ORTMAYER: Yes.

PARTICIPANT: I thought it was more like 40 percent that you actually had and you were okay up to 50.

MR. ORTMAYER: It's less than 50, but it's approaching 50, I guess.

PARTICIPANT: It's high, yes.

MR. ORTMAYER: Yeah, and it was mechanical damage.

CHAIRPERSON WALLIS: How did you mechanically damage a containment plate?

MR. ORTMAYER: We were drilling.

CHAIRPERSON WALLIS: You drilled holes in it?

MR. ORTMAYER: We were drilling core holes in the concrete, and --

CHAIRPERSON WALLIS: You drilled into the plate.

MR. ORTMAYER: Correct.

MR. KNORR: We drilled into the plate underneath the concrete mat.

CHAIRPERSON WALLIS: That's just a local, very local.

MR. ORTMAYER: Very local. That's correct.

MR. KNORR: One small spot, right.

CHAIRPERSON WALLIS: The borated water corrosion, how extensive is that?

MR. ORTMAYER: Could you please repeat that?

CHAIRPERSON WALLIS: The borated water corrosion, how extensive is that?

MR. ORTMAYER: We've observed very little actual material loss in these locations, these card holes where we -- the purpose of drilling them was to be able to monitor the plate thickness, and in these different sites, the actual material losses, you know

-- I don't know -- it's mLs. It's not extensive.

MR. KNORR: Okay?

CHAIRPERSON WALLIS: Well, I don't want to pursue this forever. I am just curious about it because I was wondering if by drilling a few holes you could really tell. If you had a place where you had water collecting and corroding and --

MR. KNORR: What we wanted to find is whether we were seeing water collecting there underneath the base mat on the steel liner underneath it.

We also were installing corisometers (phonetic) to see whether or not we were having some corrosion of the liner plate.

CHAIRPERSON WALLIS: Anyway, the staff is satisfied with what the licensee has been doing about this?

MS. RODRIGUEZ: If they're talking about the open item, the applicant agreed to commit to including valuation, repair and replacement requirements into the in-service inspection program, and this was found acceptable by the staff.

MR. KNORR: Okay?

DR. BONACA: Since we're asking questions about containment, there has been a report here on containment coatings.

MR. KNORR: That's correct.

DR. BONACA: Could you tell us about that?

MR. KNORR: We have had some containment coatings that have been degraded, and in some cases we have found them to be not qualified. We have been keeping track of the square footage of that, and we have been monitoring that and making sure that our analysis covers the amount of coating that we have discovered to be either degraded or nonconforming.

We are also -- there have been a number of bulletins and generic letters on this issue as well, and GSI-191 also covers the coatings issue. We have already contracted and are designing a new sump screening system for the containment sump, and we believe we have the corrective action in place to take care of this issue ultimately under GSI-191.

DR. BONACA: So is the containment operable right now?

MR. KNORR: The containment is operable, but the coatings are nonconforming at this point, and so we do have to repair them or --

DR. BONACA: Now, you have an estimated of 11 square feet of surface on Unit 2 containment affected by this finding.

MR. KNORR: That is correct, and we actually began a shutdown, got through about 97 percent as we went in and removed the majority of that coating so that we came within our analysis.

DR. BONACA: That's removed now?

MR. KNORR: That's correct, and we're back at full power.

DR. BONACA: How did you find this issue? Is it because now you're looking at commitments, et cetera, to determine if you have problems out there and you identify it an issue?

MR. KNORR: We're actually looking at our analyses for this, and we discovered that there was a potential for Unit 2 to have some coatings that were just slightly above what we felt was coverable by the analysis.

So it became prudent for us, I believe, to declare SI inoperable and begin the shutdown and actually go in and remove enough of the coating so that we were still within the analysis.

CHAIRPERSON WALLIS: While you are on this overview level, did you replace the RPV heads or --

THE WITNESS: MR. KNORR: Yes, both heads have been replaced. Unit --

CHAIRPERSON WALLIS: In the document it

says "scheduled to be replaced." There's nothing about whether they actually --

MR. KNORR: That is correct, and if you can go through some slides here, you'll find that --

CHAIRPERSON WALLIS: You did do it.

MR. KNORR: -- we've actually done -- right. The new head for Unit 1 was installed a couple of weeks ago, and we are in the process of starting up. So both units now have new reactor heads.

CHAIRPERSON WALLIS: Thank you.

MR. KNORR: Performance summary. We, as you can see, the capacity factors ave very good here. Some of our outages are not as short as we would like them, but nonetheless, we're doing the work that's necessary to make the plant run for a long period of time without many issues, and you can see from the capacity factors that we've been successful with that over the last cycles.

Major improvements. Unit 1 had new steam generators back in 1984. They are still in good shape. We've just done some inspections on those and have found nothing new that we have to deal with there.

Unit 2 had its new steam generators done in 1996-97 time frame.

We had split pins replaced in both units already. Unit 2 had some baffle bolt replacements in 1998 and discovered that we really didn't believe there would be anything else we'd need to do for Unit 1 there.

We are continuing to monitor that, and our program actually, reactor vessel internals program, will continue to monitor that to make sure that Unit 1 and Unit 2 are in good shape as far as the baffle bolts are concerned.

We had originally when our low pressure turbines were installed -- they did not have an integral hub. There were separate units, and we had to concern ourselves with missiles.

That is not the case any longer. We replaced all four low pressure turbine sets in both units in 1998. So we don't have to deal with that issue any longer.

We did some major upgrades to portions of the service water system back in 1998 through 2000. We had noticed some aging occurring in our containment fan cooler heat exchangers and replaced those in 2000-2002.

The reactor vessel head replacements are complete, as I've said earlier. We're scheduled also to replace auxiliary feedwater pumps in 2006 and 2007. I'm sure that all of you know that we've had some questions about our auxiliary feedwater system. We have done the calculations and say the current ones are adequate, but our margin is very low, and we need to recover more of that margin. So we're installing new aux. feedwater pumps.

In fact, they will be large enough to be able to provide the aux. feedwater if we go through to a power up rate as well.

CHAIRPERSON WALLIS: Now, you also revised the procedure for the discharge valves?

MR. KNORR: Yes, we have.

CHAIRPERSON WALLIS: But it doesn't say in the document that this solved the problem. It simply says that the procedure was revised. Did it actually solve the problem?

MR. KNORR: The procedure I think you're talking about is a recent LER that we had.

CHAIRPERSON WALLIS: AOP-10.

MR. KNORR: AOP-10, right. AOP-10 is a procedure that covers operation of a plant when there is reason to be outside the control room, fire or non-fire, whatever the case may be.

And from the remote station we discovered that the research valves did not open automatically on the start of the aux. feedwater pump from that remote location.

So what we have done is we have modified the procedure to make sure that that is done when those pumps are started. So it has solved the problem as far as making sure that we have recirc.

CHAIRPERSON WALLIS: It's a sequencing problem, is it?

MR. KNORR: Frankly, from the remote shutdown panel, it was not an automatic opening, and so we have to do that manually now.

DR. SHACK: You're also susceptible to PTS, and as I read the thing, it makes it sound as though you're going to go to a low leakage core. You haven't been operating with a low leakage core?

MR. KNORR: We have a low leakage core, but even with the low leakage core that we have right now, it would only get it us somewhere I think in the neighborhood of 2017, something like that.

And, frankly, there are a number of options that we have. One is making sure that we have more shielding for the wells in our vessel, and this is for Unit 2 specifically.

The other options are an alternate

analysis that would be approved by the NRC, and also we're quite hopeful that the NRC is looking at a revised rule to change the acceptance criteria for PTS, but nonetheless, if either the analysis or the PTS rule is not changed, there are still some other options that we have for even more shielding for the welds that we have, and we could easily make it to 60 years with those changes.

We have a couple of years to make those decisions yet.

Okay. Our original license expiration, we have a misprint here obviously. October 5th, 2010 --

CHAIRPERSON WALLIS: I'm sorry. I don't have any of your slides. So I can't read ahead, but you talked about replacing feedwater pumps. Do you have problems with the RHR pumps as well?

MR. KNORR: I don't have any --

CHAIRPERSON WALLIS: Lower than specified minimum flow rate from the RHR pumps. And it said in the document that this was being resolved by calculation. It would seem to me that it should be resolved by test.

MR. KNORR: I'm afraid that that -- does anyone from the team have any knowledge of that particular document that you're talking about?

PARTICIPANT: Which document are you talking about?

CHAIRPERSON WALLIS: Page 8 and 9 of the SER I guess it is. It says, "RHR pumps, flows lower than minimum specified values." And I wondered how this could be resolved by doing calculation. It seemed to be the desired solution.

MR. KNORR: I'm afraid I --

CHAIRPERSON WALLIS: You don't know about that one?

MR. KNORR: I'm not familiar.

PARTICIPANT: Jim, we should look at the wording in the SER to understand what it is.

MS. RODRIGUEZ: If you can point out the section of the SER.

CHAIRPERSON WALLIS: I think it's page 8 and 9 or it's a letter. It's a letter. It's on the letter inspection report. Sorry. That's where it is. September 23rd, 2005. Isn't that where it is?

Anyway, we can come back to that.

MS. RODRIGUEZ: We'll need to look it up.

CHAIRPERSON WALLIS: Okay.

MR. KNORR: Right. I'd have to look at that.

CHAIRPERSON WALLIS: Is this yours?

MR. SIEBER: That's yours now.

CHAIRPERSON WALLIS: It's not mine now.

MR. KNORR: I'm sorry, Mr. Wallis. I have not --

CHAIRPERSON WALLIS: Okay. Move on.

MR. KNORR: Okay. The application was submitted in February of 2004. We did go through the same process for the application as the more recent plants, standard LRA format and expanded content. We were one of the first plants to give all of the details for all of our programs in the application.

We used a lot of past precedence in our application. The NRC used a new review process consistent with GALL audits, actually showing up on site, which we absolutely applaud. That was a great process as far as we're concerned.

I know that you're all interested in our corrective action program. We have a common process across our NMC fleet. We have a piece of software that is actually fleet-wide. It's used throughout the nation, but for us it's called Team Track. It is in the process of being replaced with a new system, which is even more enhanced than the system that we have right now.

We do have the corrective action program in that software, and just to give you an idea, I know the last time that we met back in June, one of the questions was: what's our backlog? And what's our rate of generation?

And the backlog right now was about 3,000 of them about a year and a half ago, and we're now less than 1,500 total items that are in our backlog, but nonetheless, we still are generating in the neighborhood of 750 corrective actions and actually corrective action items every month. So we're staying ahead of that curve, and we're continuing to see a slight decline in the backlog even though we're in an outage at this point.

CHAIRPERSON WALLIS: Is this a usual number, 750 a month? It seems pretty high. Is that usual? Is it sort of the average for plants?

MR. KNORR: We have an extremely low threshold for corrective action programs. For instance, one of my team cut his finger, for instance, on some paper, that that is a corrective action that has to be written.

CHAIRPERSON WALLIS: On paper?

MR. KNORR: A paper cut.

CHAIRPERSON WALLIS: Happens all the time.

MR. KNORR: Happens all the time. Goes

into our corrective action program.

CHAIRPERSON WALLIS: Don't touch paper with finger?

MR. KNORR: I'd rather not comment, sir.

(Laughter.)

DR. BONACA: One thing, you know, you have a bullet there that says "corrective actions preclude repetition." Now, you had repetitive problems with your auxiliary feedwater system, and you know, to what extent that is tied to inadequate root cause evaluation?

MR. KNORR: We have done some root causes on just exactly that and have come to that same conclusion. We believe that our corrective actions could have been more robust, and we, you know, continue to try and make the root cause evaluation process more robust so that our corrective actions are actually successful and actually are sustained at level of operation.

I believe that --

DR. BONACA: -- you know, by just lowering the threshold and including paper cuts, it just doesn't address the repetitive nature of some of these issues, and again, so hopefully you're looking at your root cause analysis and looking at how --

MR. KNORR: We are looking at root cause analysis. We are looking at how that process works. We're looking at the corrective actions, and we're looking at the corrective actions carefully for sustainability and the capability to actually correct something so that it doesn't happen again.

I totally agree. The reason that we have lowered the threshold to where it is is if you don't identify the problems, you aren't going to be able to deal with them.

DR. BONACA: I'm not arguing about that.

MR. KNORR: Right. So really for us, you're doing the slide very well for me here. Really we want to use this corrective action program to make sure that we have some reasonable assurance that we've actually determined what the cause is; that we have those corrective actions that are going to stop any repetition that could occur; and we want to make sure that it is taken in a timely manner and an effective manner and sustainable manner.

The NRC has recently come in or the PI&R inspection last September. Their inspection report is not yet released, and I think that Patricia will maybe talking to some of that later on in her presentation.

CHAIRPERSON WALLIS: These corrective

actions, are the flooded manholes part of this correction?

MR. KNORR: Absolutely they are.

CHAIRPERSON WALLIS: I was a bit concerned that there seemed to be plans, and it said the solution is being pursued.

MR. KNORR: right.

CHAIRPERSON WALLIS: That doesn't tell me when you're going to catch it.

MR. KNORR: We have just recently, in the last couple of weeks, gone through and done another look at our manholes. We have discovered that in some cases the manholes we are not able to pump down to a level where the cables in the manholes are completely uncovered and dry.

And as you remember, our commitment is no matter what, whether they're dry cables, wet cables, whatever, we're going to be inspecting these things and doing some inspections on them nonetheless.

However, we are in the process of doing some modifications to some of these manholes to make sure that we can pump them completely dry, and we'll continue to do that. I do not happen to know what the commitment is, but I believe it's some time in the next year that those modifications are going to take place.

CHAIRPERSON WALLIS: Okay. Let's move on.

MR. KNORR: Okay. We had quite a few commitments. One of the concerns that the ACRS had was whether or not we're going to meet our commitments. In the SER, you know we have 72. Seven of them that are in the SER are already complete. Each of these commitments is managed, and we'll talk a little bit more of that in another slide I've got here in a second, in our regulatory information system and tracked to completion using our corrective action program.

For every one of our commitments we actually take a corrective action program item out, and actually I've been doing that based on our draft SER so that we have the corrective actions in place and tied to each one of those, for instance, to implement a particular program.

I've included every RAI that touched that program, the basis document for the program so that when someone opens up that corrective action program item and knows that he has to build a bolting integrity program, for instance, he knows what all of the current licensing basis information is behind it and can actually build the program correctly.

CHAIRPERSON WALLIS: Now, I notice that many of these commitments are for implementing enhanced programs in some area.

MR. KNORR: That's correct.

CHAIRPERSON WALLIS: Implement and enhance, blah, blah, blah, the program.

MR. KNORR: Right.

CHAIRPERSON WALLIS: Now, is this because the program all along had deficiencies or because of license renewal? You need to enhance the program because of something special about license renewal or what is it?

MR. KNORR: I think your second is the best way to describe it.

CHAIRPERSON WALLIS: Well, what's so special about license renewal that means that you have to enhance everything?

MR. KNORR: There are some requirements in the GALL that are above and beyond the normal kinds of programs that we would have had under Part 50, and we have programs in place. They're existing programs, but those programs have to be enhanced, and those enhancements are described in our program basis documents to make sure that those enhancements are included.

For instance, I think one of them is random testing of bolting. For instance, this is not included in our existing program under our current licensing basis, and that is an enhancement that will be required, and in fact, we're already --

CHAIRPERSON WALLIS: And this would be because the bolts are older or something. It makes more sense to --

MR. KNORR: This is for actually new bolts.

CHAIRPERSON WALLIS: For new bolts?

MR. KNORR: Coming in, absolutely. To make sure that those bolts have some integrity to them, correct.

CHAIRPERSON WALLIS: So you have more strict requirements for the new licensing period than you had before, even though the bolts are new.

MR. KNORR: That's correct.

We have a new Chapter 15 in our FSAR that's going to contain all of this programmatic and TLAA related license renewal information, and there are lots of sections that I'm sure you've seen in the SER of the FSAR sections that are going to be revised to include the changes that are resulting from the LRAA review.

Commitment management. To make sure those commitments are done, when the safety evaluation is actually issued by the NRC and we've actually taken the last version that we have gotten from the NRC, all of those commitments are included into our regulatory information system. We will take out for every one of those commitments in the SER T-track or passport corrective action item. However, we also will be entering those into a license renewal implementation management program that we have in the license renewal crew to make sure that those are tracked as well as all the small items that have to be done to make sure that they meet the requirements of the SER and of our basis documents and to make sure that those activities are implemented correctly.

So we're actually double and sometimes triple tracking to make sure that this stuff is done correctly.

In terms of implementation, this is one item that the industry is dealing with right now, and we're somewhat of a leading edge here. Our project is actually carefully budgeted through the next year, and we're going to be spending the next year implementing and doing all of the changes to call-ups procedures, et cetera, to make sure that we're 90 percent-plus done with our job.

Procedures are being marked up. Some one-time inspections have already been completed. We did some inspections this last outage on Unit 2, and a few things that we've looked on Unit 1 as well.

This implementation is going to continue. We've identified some organizational changes that are going to be needed at the site, at Point Beach as well as the rest of the fleet. Commitments are going to be completed prior to a period of standard operation or sooner, and our focus i son sooner. The sooner these can get into the lexicon of what's happening at the plant I think the better off all of us are.

Individual tasks for each commitment not completed by the end of 2006, even though they are not commitments in the SER. If we've identified a particular call-up that needs to be changed and it hasn't been changed by the end of 2006, we will take a corrective action program item out on that to make sure that it's done.

And at present, because of the implementation that we've been doing all along here, we're about 20 percent done with that implementation.

And that's the end of my presentation. Any other questions?

(No response.)

MR. KNORR: Thank you very much.

CHAIRPERSON WALLIS: Thank you.

MS. RODRIGUEZ: Good morning. My name is Veronica Rodriguez. I'm a project manager within License Renewal, and I'm here to present the staff's safety evaluation report for the Point Beach Nuclear Plant Units 1 and 2.

Along with me I have Rodrigo De La Garza, who is going to be helping me with the computer, and Patricia Lougheed, a lead inspector for Region 3, who is going to be talking about the follow-up inspection findings and some highlights on their current performance.

I would like to recognize the presence of these staff reviewers who are sitting in the audience and will be helping us with your questions.

Next slide.

Quickly, some highlights about Point Beach. Point Beach is a two unit PWR located in east central Wisconsin on the west shore of Lake Michigan. The Unit 1 operating license expires on October 5, 2010, and the Unit 2 on March 8th, 2013.

On February 25, 2004, the applicant requested a 20-year license extension. As part of the license renewal process, the staff has performed several audits and inspections. Among these, a scoping and screening methodology audit, an AMP audit, and AMR audit, a combined scoping, screening, and AMP regional inspection, and lastly, a license renewal follow-up inspection performed during the week of August 15.

The SER with open items was issued on May the 2nd, 2005. It contained five open items, two related to aging management programs, three related to aging management reviews. It had 15 confirmatory items and three license conditions.

The final SER was issued on October 1st. All open items and all confirmatory items were closed, and one license condition was slightly modified to incorporate the applicant's PTS commitments.

Like I previously said, the SER contained five open items. The first one is related to the in-service inspection program. On this specific open item, the staff rejected the use of relief requests as exceptions to the GALL report. The staff requested the applicant to provide technical justification for their exceptions and to explain how these exceptions affect aging management.

The applicant did provide their technical justifications and concluded that most of these exceptions did not affect aging management, and subsequently they were withdrawn.

The second open item is related to the bolting integrity program. On this specific open item, the staff requested the applicant to provide specific exceptions to the EPRI documents. The applicant did provide these exceptions and their technical justifications, and they also committed to perform random hardness testing.

On this open item, the applicant's justifications were found acceptable by the staff and the Region 3 staff.

And the third open item is related to PWR containment. We already talked about this; the applicant did. On this specific open item, the methodology used to address loss of material due to corrosion in the containment liner plate was found unacceptable. Therefore, the applicant committed to include an evaluation, repair and replacement requirements in the in-service inspection aging management program. This was found acceptable by the staff.

These two open items are very similar. The issue here was that the aging effect was only managed by using the water chemistry control program. On the first one we're talking about loss of material of steam generator components like the steam flow limiter that are in contact with primary water.

On this specific open item, the applicant stated that these components are made of a corrosion resistant material and that there were no industry or plant specific operating experience showing loss of material, and that's basically due to strict water chemistry control in the steam generators.

The staff revisited the guidance and concluded that the applicant's justifications are okay, and in fact, consistent with the updated GALL. This was found acceptable.

The last open item, we're talking about cracking of components in the CCW system. On this item, the applicant committed to use the one time inspection program in conjunction with the water chemistry control program and found acceptable.

Of all the confirmatory items, I would like to talk about this confirmatory item that relates or it talks about scoping criteria. On this specific confirmatory item, the applicant revised their scoping methodology by a letter dated April 29th. In this letter, the applicant removed the exposure duration term and changed their methodology and their invoking a new spaces approach. In this approach, the applicant assumes that an interaction between a non-safety related and a safety related component could occur if they are located within the same space.

Therefore, the scope was expanded. However, there were no new aging mechanisms identified. The new tables and items were added in Sections 2 and 3, and the applicant identified 14 new component types within the scope of license renewal.

This new methodology and the scope expansion was reviewed by NRR and the Region 3 staff and was found acceptable, and no emissions were identified.

DR. SHACK: I have a question about one of the confirmatory items that isn't covered there, and that's the loss of fracture toughness due to the thermal aging embrittlement. It says that the licensee is going to use enhanced volumetric inspection that meets Appendix 8 demonstration requirements.

Have people done that before? I mean ultrasonic inspection or volumetric inspection of cast stainless steel is rather difficult to do. Have people demonstrated Appendix 8 type performance?

MS. RODRIGUEZ: On this specific confirmatory item, and I was telling Tanny about it, we need to make an editorial change because the applicant committed to do VT or flaw tolerance evaluations.

DR. SHACK: Okay.

MS. RODRIGUEZ: So if you go to your Appendix 8 table, it's correct in the Appendix 8 table, and we're going to make this editorial change, and it will be reflected in the NUREG.

DR. SHACK: So they really are going to do either the flaw tolerance evaluation --

MS. RODRIGUEZ: Correct.

DR. SHACK: Do we know of anybody that's done an Appendix 8 ultrasonic demonstration for cast stainless?

MS. RODRIGUEZ: I'm not sure.

DR. SHACK: Is that something that's out in the future?

MS. RODRIGUEZ: Tim?

MR. STEINGASS: Tim Steingass, NRR, Division of Component Integrity.

I agree with your concern. The industry is has had a lot of difficulty in getting a good Appendix 8 UT examination done on cast austenitic stainless steel. They have had some improvements through the use of phased array technology. The one-sided examinations have been performed, but as you know, one-sided examinations through ultrasonic examination do not meet the qualification criteria of Appendix 8.

So that type of information is informative in that it performs a marginal information only, best effort examination. So I agree with your concerns, and it's consistent with what industry has found.

MS. RODRIGUEZ: Next slide.

On June 9th, 2005, the ACRS submitted their interim report letter summarizing their LRA review findings. The EDO and the staff responded to the ACRS letter by letter dated July 15th.

Quickly, some highlights on our response under license renewal. We gave a brief overview of the rule, and we explained how 10 CFR 5430 states that current performance is considered to be outside the scope of license renewal.

We also stated that AMPs and AMRs were audited and inspected, and that a routine follow-up inspection was going to be performed.

In addition, if the license is granted, a post approval license renewal inspection will be performed following the guidance in IP-71003.

For actions under the ROP, we stated that the region is assessing the Point Beach performance in a quarterly basis, and cull inspections were to be performed during the summer, and that additional PI&R schedules were currently scheduled for the calendar year '07 and '09.

And lastly, once the red findings are closed, MCO-305 allows up to 200 hours of direct inspections.

With this I'm going to leave Patricia Lougheed.

MS. LOUGHEED: Okay. I'm going to discuss the follow-up inspection and then go on into the current performance.

During the follow-up inspection, we had identified three areas which we needed to look into further. One was the scope of expansion that Veronica touched upon, and we looked at what was being left our under the new spaces approach to determine if there was anything else that needed to be brought into scope; looked at the one time inspection program because of the additional components and commitments the licensee had placed on it; and then we looked at the corrective action program specifically in regard to the applicant's ability to finish and complete the commitments that they were making under the license renewal application in time for the period of extended operation.

We found that the license or -- excuse me -- the applicant had made progress in all of these areas. We were satisfied with the actions being taken in regard to the corrective action program for the license renewal commitments. We believe that there are sufficient actions in place by the utility that there's reasonable assurance that the commitments will be completed prior to the period of extended operation.

DR. KRESS: When you looked at the spaces approach --

MS. LOUGHEED: Yes, we looked at the spaces approach.

DR. KRESS: -- did you find the things that weren't in scope that should have been?

MS. LOUGHEED: During the initial inspection done in March of 2005 -- four -- March of 2005 -- excuse me -- we did find some additional items that needed to be brought in. That's why we had put it on that we need to do a follow-up inspection.

During the follow-up inspection, we did

not find any additional items.

DR. BONACA: Now, we heard that according to the implementation of license renewal commitments is 20 percent complete, which means that close to 70 or 80 percent will be performed after license renewal has been approved.

MS. LOUGHEED: No, sir. I agree that the current probably is about 20 percent. That's a little bit higher than it was when I was out in August. The remaining 80 percent is scheduled to be completed between now and the period of extended operation. It's not to be completed after.

DR. BONACA: No, I know. I never said that. I said after, after the SER has been approved and the license is issued.

MS. LOUGHEED: That's true. That's similar to other plants.

DR. BONACA: And I think that our concern was related to this period of time when there will be action taking place. There will be no NRC involvement on those issues until you get into the special inspection for license renewal, and so that's the one that we saw committed to in the letter that we received from the staff in response to ours.

And so we would like to understand better how that license renewal inspection, which is done on a simple basis, addresses the concerns we raised, and the recommendation we provided, which was the one of augmenting inspections.

MS. LOUGHEED: It's true that from a license renewal aspect we will not be doing anymore inspections up until the 71003, which is right prior to the period license of extended operation.

However, under the current revised oversight program, reactor oversight program, we are continuing to do a number of inspections which will be looking at areas because, as I said, the majority of these programs are already implemented, and so we will be continuing to look at them in terms of their implementation throughout the next six years as we go forward.

We have programs. For example, one of the programs that's not been mentioned a lot, but we have a program -- the applicant has a program on open cycle cooling water. We do specific inspections in that area every two years, and as part of those inspections we'll be following up on outstanding commitments the licensee has.

We do inspections on in-service inspection every outage, and as part of those we'll be evaluating the licensee's progress. We do inspections on the corrective action program. Right now they're on an accelerated program, but at minimum it will be every two years that we will be going in and looking at the corrective action program.

We also have the resident inspectors there full time. They will be looking at things as they come up during the outages. Some of the special tests being done for the one-time inspection program. I can't guarantee every one of them, but because they are special tests, it's very likely that the residents will be taking a look at those.

We have a lot of inspection that goes on for the current program. At least it is our belief in the region that this inspection is sufficient to insure that the applicant is or that the licensee is operating safely under the current program.

DR. BONACA: Let me ask you a question now, still on this issue. Again, IP-71003, I've been looking at it. It says very clearly that you will perform an inspection on a sample basis. Okay?

Are you ever making changes to the size of the sample based on what your expectations are, what your concerns are, and so on and so forth, or is it just a routine inspection that you perform?

That's the question I have. I mean, are you defining the sample at some level that says, you know, we are concerned about this licensee's abilities ultimately to expand the sample, or don't you?

I mean, that's the technique that is used in almost everything that we do. I would like to hear about how do you treat the definition of a sample.

MS. LOUGHEED: That's kind of hard because in Region 3 we have not done any of the incident inspections yet. 2009 is when our first plant, the current license expires. So we've got another three years before we'll really get into it.

I can tell you that for these 71002, which is the inspection that I did this year on Point Beach, it said to do it on a sample basis. Well, for us, our sample was about 75, 80 percent of the systems that were being looked at. So when it came to the out-of-scope equipment, again, it said that we had to look at one system.

We looked at about 15. I know that some of the utilities complained being in Region 3 because we tend to take that work sample very rigorously, and if we have problems, we do expand the scope, and we tend to have rather thorough inspections that try to look into as many areas as we can.

I would say that, yes, I would probably expand the scope not just for this one, but for D.C. Cook, which has a longer period out there and had much higher level commitments; that we would tend to have larger samples than we would for a plant like Dresden and Quad Cities where we know they are implementing them right now; that they've gone ahead and implemented all of these programs prior to the period of extended operation.

You know, granted, in three years I may not be the person doing the program, but right now I would say, yes, that we would tend to expand our sample depending on the concerns we have with the plant.

Yes, Steve.

MR. UNIKEWICZ: I'm not sure. Did you have a question for me?

MS. LOUGHEED: Over here is Steve Unikewicz. He was the person on -- one of the people that was on that inspection back in July and August on the engineering inspection, and I kind of tapped on him because the issues that were raised there, I felt that he probably could give a better explanation than I could since I wasn't on the inspection.

MR. UNIKEWICZ: I'm not quite sure what

your questions were. At least to the item that Pat had mentioned to me , to the issue with the UHR plump and the minimum flow recirc. was current Point Beach is going through an engineering calc. and reconstruction process, if you will. They're attempting to reconstruct and revalidate many of their ECCS calculations and many of their design basis calculations.

During the inspections, almost every two out of three analyses that we looked at had some problems with it. In this particular case what it was was there was some basic assumptions made back in the mid-'80s and '90s on RHR pump minimum recirc. Now, RHR minimum recirc., there's an issue in the industry in that it tends to dead head the pump.

So we have had a lot of industry guidance in 9804, which in, among other things, that say you need to minimize time running at min flow recirc.

They recognized that at one point in time. However, what they didn't do is Point Beach has some operating scenarios and some accident scenarios where they actually do run on min. flow recirc. Well, the fact is when they looked at their current design and they did some evaluations, they recognized that they can only run it for about a half an hour before potentially damaging the RHR pump.

They never translated that back into the EOPs. So you had points in the EOP where somebody didn't recognize that, my gosh, as soon as this thing is running 20, 25 minutes I need to shut it off or else I need to somehow do some system alignments to bring the pump and let the pump run a little better, move it along on this curve.

That was one of the issues that we caught as part of the -- the team caught -- as part of the inspections, and that was the inability to translate known operating information, analyze information into operating procedures.

Now, they did put in, you know, because of questions in the '80s and '90s a full flow test line. That full flow test line does a couple of things. One of the things it does is within the IST program and within tech. specs., it verifies the operational readiness of the RHR pump.

However, since that is not -- what you're looking for in some cases in the IST is to take a minimum case, a worst case where the pump is not going to be operating where you want it to be, and really make sure that it can operate where that it can at that point for a while.

Well, they're not doing this. Since they're running the full flow test at closer to maximum flows, the pump runs a little bit smoother. The pump sort of likes it up there.

The problem is in those conditions where you're asking it to run on min. flow recirc., you're not testing it down there. The pump starts shaking. The pump starts to overheat. They're just not looking at what happens down there.

That was the issue. Now, what they've done for a corrective answer, I don't know the answer to that, Pat, because I haven't followed up on it. It's a matter of a phone call to get that answer.

But that was the issue, is the translation of design information back into the EOPs, and they really do. At least on this case they have two operating points. They have a min. flow operating point, and they have a max. flow operating point. This is not an uncommon occurrence. This is something we're seeing more and more. It's not necessarily unique to Point Beach, but where they failed is they failed to recognize it within their testing procedures.

I don't know if there's any other insights I can offer.

CHAIRPERSON WALLIS: Well, I couldn't figure out if the problem was resolved.

MS. LOUGHEED: And I think what Steve is saying is that it has not been resolved or he does not have information on the resolution, and I'll be honest. I do not have information on the resolution either. We would have to get back with probably the resident.

CHAIRPERSON WALLIS: Well, this story seems to be somewhat tangled, and does this indicate that they didn't do a good job of figuring out how these pumps work in the first place?

MR. UNIKEWICZ: The answer to that is yes, they didn't have a good idea.

CHAIRPERSON WALLIS: Or is this typical of how they do other things?

MS. LOUGHEED: This was typical of the industry, sir.

CHAIRPERSON WALLIS: Typical of the industry?

MS. LOUGHEED: Yes. At the time when these pumps were put in, there was a belief that the minimum recirc. only needed to be a few gallons per minute, and over the years we have found that that was not the case, that the pumps needed as much as one quarter of their normal flow to be able to maintain themselves in recirc.

And it was something that was not understood at the time the plants were made. So a lot of plants have gone back and made retrofits to --

CHAIRPERSON WALLIS: Does this affect long-term cooling or what does it affect?

MS. LOUGHEED: It affects the ability of the RHR pumps to perform, I guess, in a long-term cooling situation if they stay on recirc.

Now, as you say, there are ways that things can be done, for example, that got this full flow test line. The operators can take action to open up a valve so that they have more water going down the test line.

CHAIRPERSON WALLIS: But especially if the system works as designed.

MS. LOUGHEED: Absolutely.

CHAIRPERSON WALLIS: It's not necessary for the operator to do something special to achieve his objective.

MS. LOUGHEED: You're absolutely correct. This is a case though where the pump is not injecting as was designed to do but is running in standby because it has received an initiation signal, but the pressure on the reactor vessel has not dropped enough for it to inject.

So it's one of those pieces where the design of the pump is to do one thing, but it's not quite in the mode where it can do it.

MR. UNIKEWICZ: Right. It's in its long-term, slow moving events where normally you would actually see this pump come in operation within half an hour or so, but in long-term events where it may stretch on for an hour or two hours, such longer periods of time before they actually pull it into service and open up I'll say the normal accident operating alignment.

DR. BONACA: So the issue is not its performance during the accident or the end of the accident. The issue is the recirculation mode --

MR. UNIKEWICZ: Correct.

DR. BONACA: -- as it stands by.

MR. UNIKEWICZ: That's correct, and the concern, again, is that if you're sitting in a recirculation mode for too long of a time, am I going to damage the pump to the point when I ask it to perform its design basis function, it's not going to be able to do it because I ruined it in the first 45 minutes.

MS. LOUGHEED: And part of this comet because when we originally licensed a lot of these plants, we only considered the large break LOCAs, and when we started looking at small break LOCAs, we found there were different phenomena such that the RHR pump might be needed, but not be needed immediately.

MR. UNIKEWICZ: And this is not an immediate inoperability concern, nor was it an inoperability concern at the time because there was adequate testing to show that in the current configuration the pump was operable. There was enough in-service test data. There was enough operational data to say as it currently sat, it's okay.

I suspect that corrective action is to put steps into the EOPs to do those types of things for operators to recognize this condition exists. Again, that's why we have -- there isn't physical modifications. The only other physical modification would be to increase the size of that recirc. line. Certainly one of the options, not necessarily the best.

DR. BONACA: Now, on a separate issue, a different issue --

CHAIRPERSON WALLIS: Well, I'm sorry. I don't get a feeling that you've resolved the problem, and you've told me that it's an industry-wide problem. So I'm sort of left wondering what's going on here.

MS. LOUGHEED: Well, it has been an industry-wide problem in terms of -- but most plants have resolved it, and --

CHAIRPERSON WALLIS: By procedures?

MS. LOUGHEED: In some cases by procedures. In some cases it has been through installation of new --

CHAIRPERSON WALLIS: But in a bigger pipe or something?

MS. LOUGHEED: Putting in a bigger pipe, yes, sir, and it's very much on a case-by-case basis. As I said, I don't have the information about how they resolved it, and I would have to get back with you. I would have to call the resident and find out what corrective actions were taken, and I can certainly do that, but it would probably be after this meeting is over.

MS. RODRIGUEZ: We can see if the applicant has an answer for us.

CHAIRPERSON WALLIS: Are you asking now?

MS. RODRIGUEZ: Yes. Are you aware if you have modified?

MR. KNORR: I just asked a few questions.

This is Jim Knorr again from Point Beach.

I just asked my staff a few questions, and we're not sure what the corrective action is. I can make a phone call yet during this meeting and see what I can find out.

CHAIRPERSON WALLIS: So how should this committee respond when there's something sort of in the air like this? Should we just leave it up to you to fix it or what?

MS. LOUGHEED: Well, it is current operations, sir, and to be honest, it was assessed by the inspection team at the time and was deemed to be acceptable under current operation that they were willing to put it into the licensee's corrective action program, and I can understand your qualms about the way that we just put things into current corrective action programs. I cannot defend that. That is the way the program is done. That's what I have to follow.

If you want to take it up as a separate issue, that would be fine with me, but you know, we --

CHAIRPERSON WALLIS: It's like my house. I've got leaks in the plumbing, and I'll fix it someday and all that. It's not a really -- I'd never get around to fixing it. So that doesn't convince me that the right thing is being done.

MS. LOUGHEED: That is one of the items that under the current reactor oversight program, the Commission and the NRC as a whole have made a decision that for items which are of very low safety significance, that we will rely on the licensee to make the decision as to when they will get around to fixing it.

CHAIRPERSON WALLIS: And so now you've told me it's very low. That's the first time I heard that.

MS. LOUGHEED: And all I can say is the reason I would say it was a very low safety significance is that they did not issue a violation. They did not issue an unresolved item. They basically said they wrote a corrective action program document and left it like that.

CHAIRPERSON WALLIS: So if you get a small break and you're a long, long time down the road; you've ruined the pump because of something you've done and you want to bring the temperature down. You can't do it except by doing something special. That's the situation.

MS. LOUGHEED: No, sir.

CHAIRPERSON WALLIS: It's not?

MS. LOUGHEED: The situation is that when you are in a small break LOCA or a long running event that the operator needs to recognize that he can only run the pump for half an hour or a little bit less before he adds or gets a better flow path for it. Okay? So that can be opening up the test line. That can be turning the pump off, and it would be within what would be the capability of an operator at that point in the scenario that he would be able to evaluate his equipment status, and --

CHAIRPERSON WALLIS: So you have now put this all in the record. So some day when there's a small break LOCA we'll find out if --

MS. LOUGHEED: Then you can say it's all my fault. Yes, sir.

CHAIRPERSON WALLIS: Okay.

(Laughter.)

DR. DENNING: Let me follow up just a little bit more on that. Are there now in the emergency operating procedures a recognition of this or are there not?

MS. LOUGHEED: The answer to that is I do not know. At the end of the inspection it was left that the licensee wrote corrective action documents identifying the problem. We speculate that they may have fixed the EOPs, but to get the answer to that, either the applicant or myself would have to make phone calls.

DR. BONACA: I think we should make phone calls just to bring up this issue just in answer to the ACRS. We're going to be here for the next two days, three days.

MS. RODRIGUEZ: I can certainly get this action item and get a response to the ACRS, but I would like to recognize that this doesn't have to do anything with license renewal.

DR. BONACA: It doesn't matter when you're asking a question regarding the issue.

MS. LOUGHEED: And I have made no --

DR. BONACA: Some of these things have to do also because I'll give you an example. This morning we heard about the containment coating. Okay? Now, there is an issue being raised there. Is there a program, a license renewal that will deal with the containment coating?

MS. RODRIGUEZ: Actually I have an answer for you.

DR. BONACA: Okay. So you see, they have findings. You have issues, and they have oftentimes a hook into the license renewal.

MS. RODRIGUEZ: Coating is not currently addressed in the GALL. However, we have the GSI, and we have processes to incorporate this into the GALL. After the NRC decides what we're going to do with this coating issue, this will be in the ISG process, and after that gets approved, we're going to supplement the GALL with a resolution for the coatings problem.

I understand. Now, we have one open item that's not an open item, but I'm saying is an issue that has to be dealt with as you develop an ISG. Now, since Point Beach is still reviewing, inspecting, finding errors, we heard a lot of issues, errors in engineering and so on and so forth; it's likely that over the next few years, there are going to be other issues identified of this nature, and there will be some need for them to address them within the license renewal space, some of them, and that's why the importance and our insistence on an appropriate inspection level is thorough enough before walking into license renewal to cover all of these items.

And that's why the scope, okay, that has to be inspected, I think, in my judgment has to be larger than normal. So that's why we're asking these questions. They're not -- we understand the separation between current licensing basis and license renewal, but there is also a link. There are many links out there, and we have tried to explain them in our letter.

So that's the reason why --

MR. GUILLESPE: Yes, I think, Mario, once they get a renewed license, that's the license, and so the normal ROP will be inspecting against that new license in all of those lists of commitments.

DR. BONACA: I understand that, but you know, the fact itself that you find a problem here with the containment coating raises a new issue that has not been addressed within license renewal.

MR. GUILLESPE: That's true, but it's being addressed both for this plant and likely going to have to now be addressed generically across the whole industry.

DR. BONACA: I understand that.

MR. GUILLESPE: As a current problem.

DR. BONACA: Yes, and frank, but the point is what else is going to come up after you are granted the --

MR. GUILLESPE: Oh, I think we're going to continue to see things come up at every plant.

DR. BONACA: So let's just do it. Let's go ahead and make commitments and then we'll inspect them before they walk in for license renewal.

MS. LOUGHEED: And that is one of the things I'd really like to point out, is that we are continuing to inspect; that we are not going to wait until the period of license extended operation to look at these things. We are inspecting them today. When issues come up like containment coatings, like this pump recirc., we are inspecting them. We are following up on them.

I believe that I saw a couple of people leave. I believe that they're going to be trying to contact the site to get an answer to the question as to what is going on now, but it is something that would be followed now under the current operation because if there is any hint that the pumps would not be operable, that's something we want to know now. It's not a licensing question.

But Steve's impression was that it was not to the point that the pumps were inoperable.

MR. UNIKEWICZ: And, Mario, the team prior to leaving always looks at their corrective actions, and as is put into the program, part of the team inspection is to look at the item that was identified, look at the actions that are planned to be taken and make sure that they are appropriate.

If they were not appropriate at the time, and again, I don't have details, and they were unacceptable to the staff, and again, it was a group of Region 3 folks; it was NRR staff involved also; then they would not have been allowed to continue on.

Without looking at the --

DR. BONACA: I have no concern about that issue.

MR. UNIKEWICZ: Okay.

DR. BONACA: Because I know that you're on top of it, and there has to be an interim solution as well as a long-term solution that will come to the corrective action program. It's identified.

I'm wondering about what is not being identified right now that may be identified after the ACR is granted, and so therefore, the only opportunity you have is future inspections, and that's why we are insistent on that.

MS. LOUGHEED: And that's how they would be. A lot of things at Point Beach actually are self-identified. The licensee has a very good program for actually finding problems, which isn't to say that our resident inspectors aren't also very good.

I'm getting a smile out of Jim Knorr.

But I mean, both the licensee and the NRC are out there trying to find problems, and we find them, we're making sure that they're getting corrected, you know, appropriate to their circumstances and their significance.

MS. LAND: I just wanted to say something. This is Louise Land.

I'm talking about your questions about coatings. I know that the licensee had talked about the coating situation. I think it's important to understand that's with our current analyses, and as utilities look at the resolution of GSI-191 and the new designs they are going to put into place for December of '07, the analyses actually will be changed because of the new designs, and of course, the folks that are working on GSI-191 have been looking at the coatings issue.

But as far as the current situation, plants already have an analysis, and the discussion that they had was in regards to what their current analysis was, making sure that the coatings or that the failures did not impact their current analyses.

CHAIRPERSON WALLIS: I just got some input from the staff that there seems to be some doubt about the probability of the CDF resulting from this RHR issue really being a low thing. It's significant risk, especially if you discredit the operator action. It's a very significant risk.

MS. LOUGHEED: I cannot in any way comment on the assessment that was made.

CHAIRPERSON WALLIS: It just seems that it can't be left dangling. It has got to be effective.

MS. LOUGHEED: I understand that we do have somebody trying to follow up, and we will get you an answer.

CHAIRPERSON WALLIS: Thank you.

MS. LOUGHEED: I apologize that I didn't have one prior to --

CHAIRPERSON WALLIS: That's all right. Thank you.

MS. LOUGHEED: If there are no other questions, I'll go on.

Next slide, please.

Okay. This, talking about the reactor oversight process and where we are right now, and it is Region 3's assessment that the current operation of Point Beach, both units, is acceptable.

We continue to monitor that performance. We are doing increased inspections at the current time. We do have residents out there all the time. We have increased management oversight at the site.

They do remain in Column 4 of our revised oversight program action matrix. The next time that this will be looked at will be about March of 2006, is when the next time NRC will meet to make a decision whether to move them back to a lower column or to move them into a higher one which would require shutdown.

Right now I do not have any information one way or another. The confirmatory action item does remain in effect.

We did do some special inspections over the summer, and I'd like to kind of go over a few of those. Their confirmatory action letter had five areas where it had assessed Point Beach's operation as being unsatisfactory.

Two of these areas have been returned to the baseline inspection program. These are emergency preparedness and engineering and operations interface. Both of these were inspected over the summer. Significant improvements were noted in the behavior of these areas. We did not identify any findings greater than green. In the case of emergency preparedness, we did not identify any findings at all, and engineering and operations interface, we had one finding that was listed as green.

So we have returned them to the standard baseline program. For engineering and operations interface, that means that it will be evaluated by the resident inspectors on pretty much a continuous basis, and then it will be evaluated during engineering inspections which are done on a biennial basis.

For emergency preparedness, again, the inspectors look at that fairly continuously, and there are specific inspections which are done on a biennial basis.

There of the areas still remain open. These are human performance, engineering design control and problem identification and resolution.

NRC continues to assess all of these areas. They do remain adequate for continued operation. In the area of human performance, I can say that there have been improvements noticed. However, the area is continuing to be assessed because Unit 1, I believe, is in an outage right now, and we tend to notice human performance problems more during outages. So we wanted to keep it open at least through the outage to make sure that the improvement we had seen was not going to slip again.

And the other areas unfortunately I can't really talk any further about because some of it is still pre-decisional.

MS. RODRIGUEZ: The staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis, and that any changes made to this current licensing basis in order to comply with 10 CFR 5429 are in accord with the act and the NRC regulations.

If you don't have anymore questions, this concludes our presentation.

DR. BONACA: Do we have additional questions from the members?

CHAIRPERSON WALLIS: Do we have a moment? Do we have a few minutes?

DR. BONACA: Un-huh.

CHAIRPERSON WALLIS: This probably is not significant. I noticed that they were going to do functional tests of fire rated doors. Do you take the door off and take it away somewhere and test it or what do you do to do functional tests of a fire rated door?

I would think they already have been tested before they were installed.

MS. LOUGHEED: That is true. They probably were tested before they were installed, sir. However, what they want to make sure is that the testing is not so much for the door itself, but for the seals in the gaps.

CHAIRPERSON WALLIS: So you light a fire behind the door and see what happens?

MR. SIEBER: No.

MS. LOUGHEED: Well, usually use something else other than a fire that --

CHAIRPERSON WALLIS: But how do you simulate a fire without having a fire?

MS. LOUGHEED: Mr. Thorgersen.

MR. THORGERSEN: This is John Thorgersen, Point Beach program's lead.

I believe you're quoting out of our fire protection program in which we manage the aging of the fire doors. It is not talking about the fire testing and rating of the doors. It's talking about functionally testing things, such as the gap, as Patricia had mentioned, the latch to make sure it latches properly, inspecting the doors to make sure there are no holes in the doors or gaps underneath the bottom of the door.

CHAIRPERSON WALLIS: So it's not -- when I read the words "functional test of fire rated doors," I got the impression you're going to test whether the door will stand up to a fire or not, and that's not what --

MR. THORGERSEN: That would be called a fire test.

CHAIRPERSON WALLIS: So it's the words that are confusing.

MR. THORGERSEN: Or a fire rating test. A function test, you open it, close it, make sure it closes properly, latches properly, that the gaps are proper.

CHAIRPERSON WALLIS: Okay.

MR. SIEBER: That it will close by itself.

MS. LOUGHEED: Because it's one thing to test the door. The other thing is the way the door is installed, and that's what they're trying to look for.

CHAIRPERSON WALLIS: Well, I had a comment on the SER if it's appropriate. It seemed to me that there were lots of words used under every category that came up as an issue, and sometimes it was hard to me in all of the discussion, hard for me in all of this discussion -- so far I called discursive sort of commentary -- to tell if the issue was really resolved in a logical sense or if it was sort of you give a long commentary and then you say, "Well, we decided on balance everything was okay.

It would be nicer to see a sort of

crisper, logical derivation of this "okayness."

But it seemed to me on general, that this SER seemed to be more thorough than some of the other ones we've seen, perhaps because of the nature of the plant and the history, and that's perhaps why you went into more discussion of these various issues.

So in that side, I would compliment you --

MS. RODRIGUEZ: Thank you.

CHAIRPERSON WALLIS: -- for appearing to be more thorough, at least putting in more action, more stuff, but still I would like to see some of the resolutions of the issues being crisper.

DR. BONACA: Anymore comments from members, questions?

(No response.)

DR. BONACA: If not, I thank the staff and the license people for the presentation.

MS. RODRIGUEZ: Thank you.

DR. BONACA: And I'll give the meeting back to you, Mr. Chairman.

CHAIRPERSON WALLIS: So we have made up time on this one.

DR. BONACA: A little bit.

CHAIRPERSON WALLIS: Thank you very much. Thank you, presenters, for your presentation.

We will now take a break until 10:15.

(Whereupon, the foregoing matter went off the record at 9;52 a.m. and went back on the record at 10:15 a.m.)

CHAIRPERSON WALLIS: The next item on the agenda is grid reliability and its impact on plant risk. I will hand the meeting over to my colleague, Jack Sieber, to lead us through this one.

MR. SIEBER: Thank you, Mr. Chairman, and good morning.

I'm going to depart from the standard procedure of just making a brief introduction and introducing the staff to speak because I think this issue is a very complex issue not only from the standpoint of understanding what's going on, but knowing who all of the players are and what each one of them is doing or attempting to do, where they are, when they're going to be done, and how these things interact with one another.

And to do that, I will talk a little bit about the history, perhaps at the risk of duplicating part of the staff's presentation. If I do that, then I apologize in advance for it, but I will do it anyway.

(Laughter.)

MR. SIEBER: You know, grid instabilities have been with us for almost ever, since that is in --

DR. POWERS: Since there was a grid.

MR. SIEBER: That's right. When we invented grids, instability came along with it.

And in the history of disruptions, major disruptions to the grid, basically we started with a major disruption in 1965 in the northeast blackout, which caused a blackout in New York City, among other things. From a generation standpoint, the Consolidated Edison, their largest generator called "Big Alice" was a generator that did not have back-up DC turbine oil pumps, and so when they suffered a loop event, the turbine tripped, slowed down, and since it had no lubricating oil, wiped its bearings and put it out of commission for a long time.

That had some impact on nuclear power plants, but in '65 there weren't very many. I think Indian Point 1 was one of them, and so it did not raise a major significance.

In 1996, in August, there were two major blackouts in the West. Around Southern California was the center, and that also caused loss of off-site power events to a couple of nuclear plants.

On August 14th, 2003, a major part of the

Northeast and the Midwest in the United States and parts of Ontario, Canada suffered a blackout that lasted basically for a couple of days. It caused loss of off-site power events to nine United States nuclear power plant, eight of which were operating at or near full power at the time.

Fortunately, on-site back-up power operated properly for all of the nuclear power plants, as they are designed to do. On the other hand, there is some remaining concern that loss of off-site power events are becoming more frequent and, therefore, changes the probability of an accident should some of the backup or mitigating systems fail.

Now, we got a report last year from the staff, which is "Station Blackout Risk Evaluation for Nuclear Power Plants," and it makes an interesting statement, and it talks about the mitigating ability based on SPAR analysis of plants to mitigate loop events compared to the previous assumptions on that, and if you read the conclusions, they find that the overall results indicate the core damage frequencies for loss of off-site power station blackout are lower than previous estimates based on this study.

And it turns out that the reason why that is is because the reliability of diesel generators has been improving over the years, and that the estimates previously used for basically on-site emergency power systems frequency of failures was greater than the current experience is.

Notwithstanding that though, it is clear that a loop event, and particularly a station blackout event, which would fall from a loop event where mitigating back-up power systems would fail is a significant contributor to core damage.

Now, the NRC recognizes this. The staff recognizes this, and they have taken a number of actions, and along with the Federal Energy Regulatory Commission and the United States government, the Congress, in fact, in April of 2004 following the Northeast-Midwest blackout, a joint U.S.-Canadian task force issued a report from their investigation which found that several entities, in other words, transmission companies, violated NERC operating policies and planning standards, and the only way to really fix this since the planning standards are not enforceable at the present time, is to pass legislation, enact that into law, and modify the Federal Power Act in order to make the standards exist, make everyone abide by them, and make them enforceable via penalties.

In April of 2004, FERC issued a grid reliability policy statement. In September FERC asked the Congress to legislate authority for FERC to promulgate and enforce grid reliability standards.

August 8th, 2005, Congress passed and the President signed into law the Electricity Modernization Act, which adds Section 215 to the Federal Power Act, and that establishes an electric reliability organization, which is initialized as ERO, to which regional bulk power organization or transmission companies like PJM or ECAR or in the West WECC would report.

And of course, this new entity would establish and enforce the standards. Now, the standards are being written as we speak by the North American Electricity Reliability Council, which the initials are NERC. So you have FERC and now you have NERC. NERC is the standards writing, and FERC is the overall federal commission that oversees this process.

Now, the desired outcome of the FERC process is to provide enforceable standards in the operation and maintenance of the transmission grid to promote greater stability and to lessen the opportunity for major power disruptions, including loop events to nuclear power plants.

Now, the NRC's interest, rather than stabilizing the grid, the NRC's interest is having nuclear power plants prepared to deal with grid instability and, in fact, the interest really is our licensees obeying the rules and regulations of Title X, which is 50.63, which talks about on-site power supplies; 50.65, which is the maintenance rule, which says you have to take into account risk before you remove equipment from service for maintenance.

And an example of this, a recent one, was when the hurricane was coming into the United States. One utility decided to take one of their diesels out of service to do preventive maintenance. Now, that may not be the wisest thing. You would have to take an umbrella with you to the diesel generator. It wouldn't be available for service when the loop would occur, which it absolutely would occur under those circumstances, and there are some other examples as to where the maintenance rule needs to be more highly respected, so to speak.

The third thing is GDC-17, which talks about back-up power supplies.

In April of 2004, the staff issued and the regions performed inspections to gather information about the state of mind and the state of procedures that utilities use to coordinate and contact their system operator.

In November f last year, the staff briefed us on this situation, and on April 12th of this year, the staff issued a draft generic letter for public comment, of which there were 14 commenters and lots and lots of comments.

April 26th, the staff briefed the commissioners, and the commissioners sent them a staff requirements memorandum that says, "Go ahead with your generic letter and get it out by December 15th," which when I read that I underlined that because that's part of the talk. The staff would like to do what the Commission has told them to do.

And so now the staff has issued for comments the draft generic letter, received the comments back, analyzed those, prepared a final draft generic letter, and so they are here to tell us about their work.

Now, as part of this presentation, Mr. Alex Marion from NEI has asked for a few minutes at the conclusion of this session to make a statement on behalf of the industry.

So without further ado, I would like to introduce to you Ronaldo Jenkins, who is in charge of the grid reliability program for the NRC.

Ronaldo.

MR. JENKINS: Good morning. I'd like to thank you for your recap of where we are. You've done a much better job than perhaps we would in this short period of time that we have.

My name is Ronaldo Jenkins. I am the Branch Chief of the Electrical Engineering Branch for the Division of Engineering in the Office of Nuclear Reactor Regulation, NRR.

I would like to thank the ACRS for inviting the staff to today's meeting. The staff has been working to resolve electrical grid reliability issues, and the purpose of this presentation is to present the draft generic letter or GL for your review and endorsement.

Next slide.

As the agenda indicates, after my overview, Mr. Paul Gill will discuss the public comments on the draft generic letter and staff changes to the document.

Mr. Bill Raughley from the Office of Nuclear Regulatory Research will discuss the status of supporting actions in concert with the North American Electrical Liability Council, or NERC, to model nuclear power plants in NERC planning models.

Next slide.

This is a list of acronyms that we typically fall into and basically for those who are not familiar, we will try to spell them out at least initially.

CHAIRPERSON WALLIS: The first one is a real problem for us.

MR. SIEBER: Yeah, I never did get that one.

MR. JENKINS: Well, at least we got it spelled right.

PARTICIPANT: Well, how is it pronounced? Is it "acres"?

MR. JENKINS: Well, next slide.

This is the second list, and it seems as time goes along we keep adding more and more acronyms.

MR. SIEBER: Is there such a thing as a real time computer program that does line loss and load float? I mean, is it really real time?

MR. JENKINS: It's real time from the point of view of the updates. Typically, they are as fast as every five minutes, and so they reflect the state of the system.

MR. SIEBER: Well, they have built into it equipment that is physically out of service or circuit breakers that are physically open, but typically they do a Monte Carlo analysis of the probability of something else happening and what that will do to the system from the standpoint of line loss and load flow; is that correct?

MR. JENKINS: Well, they --

MR. SIEBER: It's probabilistic in nature.

MR. JENKINS: There's two types of studies. One is if you're going to do a Monte Carlo simulation, you're trying to identify what the probability of something occurring.

MR. SIEBER: Right.

MR. JENKINS: Typically they do the load flow analysis that determines what would be the voltage if they lost a critical element, and so they do this "what if" simulation repeatedly, and independent system operators like PJM, they alarm their systems such that if they lose a critical element, the operator will be informed that they may not be able to, for example, power nuclear power plant buses.

So we've been talking with them over the years extensively, and they are very much aware of nuclear power plant needs.

MR. SIEBER: Yes, I would point out that PJM, in my estimation, they were one of the survivors of the 2003 blackout by being alert and on top of things and taking action right away.

MR. JENKINS: Yes, that's the normal response. The normal response is to isolate your system and protect it. And when we talked to them after the event, they basically said, "Well, we were kind of lucky, but we were definitely looking to contain it," once they were aware of it.

MR. SIEBER: Right.

MR. JENKINS: Next slide.

You already had talked about a lot of the chronology, that on August 14th, 2003, the largest power outage in the history of the country occurred in the northeastern United States and parts of Canada. Nine nuclear power plants tripped, and eight of these, along with a nuclear power plant that was already shut down, lost off-site power.

Although the on-site emergency diesel generators, the EDGs, functioned to maintain safe shutdown, this event was significant in terms of the number of plants affected and the duration of the power outage.

One of the responses on the staff's part was to perform a deterministic risk evaluation and we concluded that there was a certain urgency to address the next summer to identify what issues that need to be addressed in light of this event.

And at the November 4th, 2004 ACRS meeting, we spoke of the concerns that we had regarding the reliability of off-site power and nuclear power plants.

And we used both risk informed assessment and deterministic techniques to evaluate the safety significance and the priority for these issues, and in December of 2004, the staff concluded that a generic letter was warranted based on those reviews and the results of the temporary instruction 25.15-156, which was conducted during the summer of 2004.

Next slide.

To conclude the chronology, the staff was asked to issue the final generic letter by December 15th of this year. I would note that there were two temporary instructions completed to assess the operational readiness of nuclear power plants during the summer periods of 2004 and 2005, and the results both indicated a high degree of variability on the use of nuclear power plant/TSO, or transmission system operator, protocols.

So moving forward, the next slide we talk about the structure of the generic letter. How did we arrive at the questions?

After the staff's assessment of the August 14th, 2003 blackout, we looked at the risk insights and the regulatory requirements, and we developed the regulatory information summary 2004-05.

We then based the general letter questions on that risk, on that regulatory information summary, and that risk was issued in April of 2004.

So short term, the staff's response was to issue a temporary instruction for the summer of 2004, and we issued the risk 2004-04 to communicate the staff's expectations in this area to licensees.

The questions cover GDC-17 and technical specifications, maintenance rule, and station blackout.

I would like to turn it over if there aren't any questions to Paul Gill for the next part of it.

CHAIRPERSON WALLIS: Those four questions, the subquestions, the actual number of questions is very large.

MR. JENKINS: It's a reflection of the complexity of the issues that are raised. We had a choice. We could have devised eight questions that were very general and broad, and then we would be going back and forth, questions and answers, with individual licensees or we could use the subparts to narrow in on the areas of concern or areas where we wanted additional information.

So we chose the subpart approach to basically if the response was as we expected, then there was no need for any further information. So we thought that that would be more efficient than just eight simple questions.

Yes, sir?

MR. SIEBER: It seems to me that to some extent the efficacy of a licensee's answers to these questions depends on the skill and ability and infrastructure of the transmission system operator, TSO. In other words, if you're running a power plant and your TSO really doesn't have all of these tools and is not a real good communicator, there is nothing in place other than the FERC action, and we'll have to see how that turns out; there's nothing in place to sort of up the standards of the TSOs.

MR. JENKINS: I guess our main point is to ask the questions to identify if there are areas of concern, that is, compliance. How do you know that your off-site power source is operable.

MR. SIEBER: Right.

MR. JENKINS: And as the licensees, that's your responsibility. Now, if it turns out that there are areas of weakness that exist, then we need to know that.

MR. SIEBER: Okay. I'll ask one other question and try to be quiet for a while.

Obviously the ultimate success here as far as the goals that the staff has set forth in the generic letter and from the standpoint of a more reliability national grid system depends in my mind on cooperation between FERC and the NRC, and I know by reading through the reading list that FERC people have gone to your workshops and there has been some interaction, but I think that that is one of the elements that's important, and as you go through, you may want to address where that has occurred and what success you think you've had.

DR. DENNING: I had a quick question, and that relates to one of the bases for moving forward here is the determination that there is a risk issue involved here, and I was wondering if you additional risk studies.

We've looked at the loss of off-site power study and the static blackout studies that were done by research, and neither one of those studies would lead to -- I mean, there's some indication of a need for having a high degree of surveillance in the future to make sure that there is no problem here, but I wouldn't say either one of those gave a perspective of a risk that's higher than what we've believed the risk of loss of off-site power has been for the last 25 years.

In fact, the perspective is certainly that it's less than it was. Whether it actually is or isn't, of course, there's some reasons why it almost certainly is lower in terms of its diesel generator performance.

But was there something other than these studies that led you to draw those risk insights?

MR. JENKINS: Following the event, 2004 and August 14th, 2003, the staff convened an expert panel, PRA panel, to try to get our arms around this particular issue.

The studies you are referring to, they do provide some good information. However, what we are seeing is that there's an increase in risk in the summer months, and basically that's one of the studies, the earlier study that was done, that there's an increased amount of risk.

Mike Cheok of the Office of Research, do you want to add anything?

MR. CHEOK: I guess what I would like to add is reference to the NUREGs, the draft NUREGs that you were referring to. You're right that we show that the risk has come down a little bit compared to ten years ago for several reasons, but what we also found was that on the average annualized basis, the risk has come down, but if you break it down to the different subparts, for example, if you just look at the risk from grid alone, you find out that the risk has increased, and we find out that things like, you know, the dominance of events during the summer months also causes a concern, and also the fact that the durations of some of the events are getting longer may also be causes of concern.

MR. JENKINS: And we have a slide that shows basically some of the numbers. We'll show that later.

MR. SIEBER: But from the standpoint of public health and safety, which takes into account everything, the risk has slightly declined.

MR. JENKINS: Right.

MR. SIEBER: And that's what I read here.

MR. JENKINS: And that's reflected in previous comments where you noted that what we called the plant centered events --

MR. SIEBER: Right.

MR. JENKINS: -- have decreased. So when you add the total number of events from the three different sources, whether plant centered and grid, the plant centered portion has decreased, and that has brought down the total number.

MR. SIEBER: I guess we're not asking questions like this to pick on you, but to just make sure there's a clear record as to what's going on.

MR. JENKINS: Right.

CHAIRPERSON WALLIS: I have a question for you. These questions seem to have the intent of determining whether or not the licensee is complying with certain regulations.

MR. JENKINS: Right.

CHAIRPERSON WALLIS: I wonder had you thought out how the answers to the questions enable you to determine whether or not he is in compliance.

For instance, you've got such detailed question, such as, you know -- just pick one -- how frequently does the RTC program update. Now, if he says five minutes, ten seconds, two hours, ten days, which one of those is in compliance?

And you've got all of these answers. Someone has got to decide if this whole compendium of answers puts the licensee in compliance or not. Have you thought about how you're going to do that?

MR. SIEBER: A good question.

MR. GILL: I'm Paul Gill from Electrical Engineering Branch.

As a matter of fact, what you alluded to is one of the comments that we received, and in our response and in what we are trying to say is that there is, in essence, no regulatory basis for requiring these. However, this type of information is needed, and we need to know from the nuclear power plants as to who's using it, how often they're updating it so that we can look at that information and come up with a recommendation in terms of staff if we do need to go there to make a requirement.

So at this point I think it's premature to say that, you know, we have a specific criteria as to what is going to be acceptable. What we are trying to do is to collect information through this generic letter so that we can put our arms around it and look at the overall industry and see what is the best avenue to deal with this issue.

CHAIRPERSON WALLIS: You're talking about a research investigation rather than a regulatory one.

MR. GILL: Well, I wouldn't say that, but I think it's the practical information that we need to know. We know there are entities that are using these programs. They're updating five minutes, 15 minutes or even sooner.

The question is, you know, what are these programs and what information are they providing, and what do we need in order to determine the functionality of the off-site power system.

The real key issue here is: is the off-site system functional? And all of the regulatory requirements, these are embodied in the tech. spec., which then refers to the operability. So at this point, I don't think either the licensees or we have a real sense of determining whether that off-site system is operable or not.

And there have been events that have indicated to us that just looking at the meter does not tell you the system is going to be operable if a unit trips.

Now, you have adequate off-site power when the unit is at power. However, should the unit trip, you need the off-site power system per the GDCs and the regulations.

Now, the question is: how do you determine that off-site system is going to be operable given a unit trip? I don't think anybody can say that it is going to be unless you basically rely on these tools to tell you what's going to happen.

MR. SIEBER: And let me make a couple of comments. In February of next year, FERC will have finished it notice of proposed rulemaking process and put rules in place establishing the ERO and the standards. So if you were to send out this generic letter next February, you may get different answers than you will sending it out in December because there's going to be more infrastructure there, more organization and more knowledge.

Now, I guess I pondered that, and I said, on the one hand, you know, that's a good idea to wait a little bit until FERC does its job. On the other hand, I got this SRM in my hand that says, "You do your job by December 15th," and so I'm sort of torn, and I'm trying to evaluate whether you're going to get enough information and good enough information to tell you something when the organization that will provide these answers to licensees is not yet in place.

Some regional system operators do a really good job right now. Some others do not.

MR. GILL: I think the main focus of our questions is the licensee's part in this relationship, in this interface,what the licensee knows and is aware of versus the TSO. We're not directing questions toward the TSO or any of the external organizations that are involved in the grid, but there must be a handshake between the two organizations in order for there to be a proper functioning of the system.

Now, to get back to your question and hopefully try to be a little bit more direct on it, the answers back will inform the staff as to what exactly is that relationship, and the reason we went down to the level of detail is because when we talk about emergency diesel generator relaxations of allowable outage times, where we're going from three days to 14 days, then the amount of time that this method that they use to assess where they are is important, whether they use the real time contingency program or whether they use a bounding analysis.

We would like to know whether these intervals, these updates are compatible with each other.

And so I don't think we're -- this is my personal opinion -- I don't think that we're going to be talking about five minutes versus an hour on an update, but you know, if there are days or weeks or months in these updates, then that might be an area for us to explore.

MR. SIEBER: Of course, it's sort of an unusual thing just from the standpoint of the nuclear plant operator. If the system operator says, you know, "My contingency program says that we're sort of on the edge," and the plant operator says, "I think the off-site system is inoperable," my tech. specs. say shut down.

If it wasn't messed up before, it will be after he shuts down, you know. So it's not clear that everything really works together here.

MR. GILL: Well, there is a time period before he shuts down

MR. SIEBER: Yeah, I know.

MR. GILL: Twenty-four hours or 72 hours, and as a matter of fact, I've read some event notifications where they exactly did that. They went in to declare it inoperable and then came back when the voltages were restored. So there are some plants that are actually doing what the generic letter is seeking information on. They're already ahead of us, but then there are others that --

MR. JENKINS: We don't have any information on.

MR. GILL: Right.

MR. SIEBER: The interesting thing will be for you to tell us what the answers were to all of the questions that you're asking.

MR. GILL: We will provide you the answers.

MR. SIEBER: Okay. Thanks.

I think we ought to give you a chance to go on with your presentation.

MR. GILL: Okay. Well, again, I'm Paul Gill.

I have the task of looking at the industry comments, and as you mentioned, there's a whole lot of them. In essence, they were from various nuclear power utilities, owners groups, and organizations that represent given nuclear power plants, and the Nuclear Energy Institute.

We received also a comment from Oak Ridge National Laboratory, State of New Jersey, and the Bonneville Power Administration, as well as from an individual via an E-mail.

MR. SIEBER: I would point out that Bonneville is a TSO located in the northwest if the country.

MR. GILL: Right.

MR. SIEBER: And it has probably got six investor owned utilities and a whole bunch of cooperatives and government-type utilities, and they cover, you know, five or six states.

MR. GILL: And I guess the copies that we furnished to you list all of the various entities that made these comments.

MR. SIEBER: Yeah, and everything they said, yeah.

MR. GILL: And, again, these comments were in the areas essentially -- if you look at the generic letter, we are seeking information in three areas. One deals with the GDC-17 area and the tech. specs. How do you meet the tech. spec. operability requirements, and not necessarily how you meet GDC-17, but the operability aspect or the functional aspect of the GDC-17.

Now, GDC-17, as well as if you look at some of the other GDCs, for example, I believe, 33, 34, 35, 38, 45 and 41, have very specific requirements for an off-site power system to be operable, and it says you have to have an on-site system as well as off-site system. Assuming one is not available, the other should be.

So if you read those, it seems to me that there is an operability or a functional requirement that this system has to be operable or functional.

And then, of course, you know, those are imbedded in the tech. specs. and embodied in the tech. spec. to tell you what the operability requirements are.

And similarly, as you mentioned earlier, that 50.65 requires a risk assessment before you take risk significant equipment out, and as well as station blackout area, where the station blackout where the station blackout, for example, has a requirement in our Regulatory Guide 1.155, as well as the Numarc 8700 document, which was used as a basis for complying with the station blackout rule.

Both of these documents have very specific requirements for having procedures for restoring off-site power and having these procedures, you know, to bring power from other sources around the plant, and so the question that we are seeking is to since now the utilities are deregulated, we are asking the nuclear power plant operators in the area how have you handled that. You know, tell us about, you know, what have you implemented.

Because your old load dispatcher through which you had access to the outside system is no longer part of that organization. Now you're speaking with a TSO or ISO or RC and RA. These are all different entities that control the grid. Now, tell us about what kind of arrangements have you made.

So we are asking information. We are not telling what to do, but at this point we are reaching out and saying tell us, you know, what have you implemented.

And similarly, also station blackout. When we through implementing that rule in terms of determining the coping duration, there was a very specific requirement that looked at the experience of the off-site system in terms of an interval given 20 years. It looked at the operating experience over a 20-year period and say, "How reliable was your grid related to grid related failures?"

You know there are all kinds of failures that you could lose your off-site power, but one of the criteria which took into consideration how often you had a failure that was related to the grid itself, and based on that, your coping duration was determined.

So now, given that we had a number of

failures as well as, you know, looking at a station blackout rule in view of the August 14th, 2003, how does that impact that assumption?

So we want to validate that assumption. Indeed, it is still, you know, valid because it is a living rule, and we need to. So we are asking information on that.

So we divided these comments that we received from the industry into those three major categories, and then there was a comment on schedule, which we then adjusted according to that. There were some questions about backfit and legality of what we were asking in our response in conjunction with our legal office. We provided a legal response to that, and there were comments that we couldn't bend into these categories. So we called them miscellaneous comments because there was an overlap.

Some questions basically addressed all of these areas in common. So it was very hard to, you know, sort it out. So we said, you know, these miscellaneous comments, and I'll go over some of the highlights of these comments.

Now, I made mention that you mentioned in terms of these eight questions that we mentioned, four in the GDC-17 area, two in the maintenance rule, and two in the station blackout area, we mentioned that they had subparts. If you look at the draft generic letter that went out, we had not broken them into subparts. They were just general questions.

And one of the comments that we received way, "Hey, this is too cumbersome. It would be better if you break them down into, you know, specific questions," which you know, we took that and thought that was a good idea. So we have now broken each question into subparts, and many of these subparts are yes/no answers. Okay? They're not very long.

We're asking are you doing this, and the answer could be yes or no, you know. So they're really -- what I want to say is they're not as long or as big as one might think. There are some very simple answers to these questions.

Next slide.

Now, since GDC-17 is the one with four questions, we received most comments in that area, and the gist of the comments that we received was essentially saying the formal agreements between the nuclear power plant and the TSO are not needed or not essential, not required. Use of the RTCA, which is the real time contingency analysis, is not required or needed.

And then GDC-17 is a design requirement. It's not an operational requirement, and I think we talked a little bit about that, and I might dwell on that a little more on it as we go along.

Also, there was a comment saying plants that are not designed to GDC-17, you know, how do we handle that. They're not, you know, required to address that.

And, you know, I will talk about that. If you'll look at the plant, you know, FSER, USFAR and you find that all plants have a criteria to which they were licensed, it may not be GDC-17. It is probably a plant specific design criteria, such as the old, you know, Atomic Energy Commission safety criteria.

And you'll find that each plant has a requirement for off-site/on-site power, very similar to GDC-17.

So what we did is in the generic letter, we made that, you know, change and said if you're not designing for the GDC-17, then use what your licensing basis is, and also the comments in terms of the operability determination should not be based on contingency analysis or "what if" models. We talked a little bit about that.

Next slide, please.

And, again, as we already have stated, that the purpose of the generic letter is to go out and get information so we can better understand what each nuclear power plant, you know, is doing in terms of this handshake with the TSO or their transmission system operator, so that we can understand what communication exists.

How do they, you know, let each other know that, you know, there is a great distressed condition. Does the plant know before you take some equipment out, risk significant equipment out?

So the generic letter, in essence, is asking or seeking information in those areas, and in terms of the GDC-17, not implying operational requirements and we disagreed with that comment because if you read not only GDC-17, and I mentioned these other GDCs, you know. There are a number of them, such as mentioned 33, 34, through all the way up to 41 or 48. They have very specific requirements for the off-site power system to be available, given that on site is not available. It says that you have to assume on site it not available. This system should be available to perform the safety function.

And those are embodied in the tech. spec. Tech. specs. have specific requirements in terms of this off-site power, not only in terms of number of lines, but as well as in terms of now we have the degraded grid voltage set points, which tells you that you have to maintain a voltage at those levels in order for the safety equipment to be operable.

And if you don't have that level of voltage, those relays are going to disengage you from the off-site system and take you over to the on-site system, given that the on-site system is available.

So when you look at all of these requirements, it seems to me, at least in my humble opinion, that there is a very definitive requirement for the off-site system to be functional.

Now, the question is: how do you determine is it functional given the greatest stress?

Now, the nuclear power plant operator can't sit in a vacuum and say, "I'm looking at the meter and I have the right voltage." Indeed, when the unit is at hover, it's supporting that voltage.

Now, should you have a unit trip, you're going to lose that support that is providing to the grid, and your voltages are going to go down. It means that you are not going to have a functional off-site system.

So this is a key issue that we're trying to get our arms around in terms of how does the plant operator determine, given that you are in a stress condition, that the off-site system is going to be functional?

MR. SIEBER: Yes, this was a question in the 1970s and '80s, and a lot of nuclear power plant operators installed things like tap changing transformers, capacitor banks, et cetera, so that they could withstand the loss of their own unit or adjacent units and still maintain proper voltage.

I remember those campaigns pretty distinctly because we had to do a number of things ourselves, and it seemed to me at the end of that that sufficient steps had been taken by the industry so that unless off-site power completely disappeared or was extremely degraded and unstable, that the plants could withstand their own trip or the trip of adjacent units without losing or going below minimum voltage or frequency where you would end up tripping off your own emergency equipment.

MR. JENKINS: Things have changed, and that's really kind of where we're coming from on this, is that if you look at Diablo Canyon, for example, in the FSAR, they refer to the support from Morro Bay, another generating station, as being part of their need to have off-site power; that that unit generating provides them with support to maintain off-site power.

And part of the deregulation associated with Morro Bay being sold off and the whole restructuring in the California system, they had to make a number of changes in the way their system was set up, but things are --

MR. SIEBER: But those are basically design issues. You know, you're supposed to foresee all of this stuff, but inoperability determination, you know, you sit there right now and you look at your meters, and the voltage is okay, and you know that you have given your switchyard conditions the ability to cope with the loss of your own unit.

But then you're supposed to determine operability by somehow looking into the future with a real time contingency plan and deciding on the basis of the probability whether you're going to be operable five minutes from now or two hours from now or two days from now, and that's pretty tough.

MR. JENKINS: Just to clarify, the real time contingency analysis program looks at basically a "what if" generating machine, which is that if I lose this transmission line, will I have sufficient voltage.

MR. SIEBER: This power plant or whatever.

MR. JENKINS: If I lose this generating unit over here will i have sufficient voltage?

MR. SIEBER: Right.

MR. JENKINS: So, you know, it doesn't really determine probability so much as a contingency. Looking at that first contingency, can the system survive the contingency and still provide adequate voltage?

MR. GILL: And if I may add to that, when we look at, you know, the design criteria, if you go into the SRP, I mean, there's a whole list of this contingency type things that are required when we license the plant to have them assure that it's going to work.

So it's not as if this is something new that we're throwing on the table. This was always there. The plant is designed, licensed to that so that it should be able to withstand a loss of critical transmission line or unit trip or a large, you know, load or a generator.

Now, the only difference between then and now is that then was one entity. So there was confidence that they were going to operate in a manner that was consistent in the best interest.

Now, you have a different entity that has a different interest, and the question now is: does the plant know what's going on on the bridge? Is there a good communication interface that tells them, okay, things are happening? We're in a stress condition. You shouldn't be taking, you know, certain equipment out, such as an emergency diesel generator, for example.

MR. SIEBER: I think it's even more than the fact that we have now decentralized organizations and created generating companies and merchant power plants and all of that. But the biggest effect is that the infrastructure, transmission line, substations, generating units versus the load demand, the margins are getting smaller and smaller because there isn't enough cash flow into the infrastructure to expand it to meet the need.

And nothing that anybody is doing right now really deals with that situation, and that to me is a root cause.

MR. JENKINS: Yes, just another clarification. We certainly don't want to give an impression that all of the U.S. is deregulated, and you have a mix. Some utilities are still vertically integrated, but they are all under FERC Order 888, which requires that they operate as if they were deregulated.

MR. SIEBER: Okay.

MR. GILL: Next slide, please.

MR. SIEBER: Yeah, let's see if we can hustle.

MR. GILL: To basically summarize, we looked at the comments. We evaluated them, and as a result of that, as you can see from the hard copies of the GL that you have received, there's a lot of strikeouts, and we have made a lot of changes to accommodate the comments, and we defined the TSO terms and the protocols.

We are saying that they are not required per se, but you need to have that information and tell us how are you getting that information and what kind of information are you getting.

So we have, yo know, modified or changed the generic letter in the spirit of the comments that we received.

And also in the maintenance rule area, where some of the comments were in terms of seasonal variations, we are saying that per se they are not required, but tell you, you know, have they occurred, and if they have occurred what impact they had.

So the GL, you know, has been revised to reflect these comments. And similarly, in the station blackout area that we have, essentially, you know, explain the reasons why you're asking for that information and what's the basis for it.

So as you can see, we have made substantial changes in the generic letter, but still, you know, the gist of this whole thing is trying to seek the information so we can better understand what's going on and, therefore, come up with recommendations to the Commission in case we do need to go to new rulemaking or whatever we need to do.

And also in the Mendez rule area, we have defined what we call the grid risk sensitive equipment in terms of that equipment that is sensitive to, you know, or may cause grid risk. So you'll see that being elaborated more in the GL.

Next slide, please.

And also in the GL we have added a sub-question or a line item about training. The SRM that was issued on May 19, 2005 requested that the staff review training and examination programs in this area. That is the area between the NPP operator and the grid operator in terms of the training aspects that are, you know, involved there, and also based on the RTI finding and follow-up on that, we found there were at least in one instance that I know inadequate corrective actions associated with the training.

So we felt prudent that we should add a line item to Questions 1, 3, 4, 6 and 7 that deal with procedures in this area, that we need to get from the licensees or the nuclear plant operators. You know, how are they handling this training of their operators in this area?

MR. JENKINS: At this time we'll have Bill Raughley come up and he's going to give his short presentation.

CHAIRPERSON WALLIS: Okay.

MR. RAUGHLEY: Bill Raughley from the Office of Regulatory Research.

I was asked to give a brief presentation on the work us and NRR are going with NERC and FERC, and I'll provide you with the summary purpose and some of the uses of the information.

Next slide, please.

From past presentations, you may recall the Commission endorsed SECY 99-129 recommendations to work with the electric industry and recently encouraged MOAs with NERC and FERC, which RES and NRR teamed to put in place. NRR got us started on this task as part of the agency grid test action plan. They asked us to obtain and analyze grid operational data and look for some indicators of grid health.

And as we got into this, you really can't drill down unless you have a model of the grid and the nuclear power plants. And recognizing that the NPPs are connected to the grid and subject to the same condition, this effort is to better understand the grid or the preferred power supply and provide a basis to attack the problem from an engineering perspective.

So we look in that. We're working quantitatively with the electric industry and experienced electrical engineers to include the nuclear plant loads, particularly following the trip and the trip with the accident that we've been talking about, the TSO limits, the NPP, the greater voltage set points and for the PWRs, the under frequency set points in the grid models.

And that will be the first pass. The second pass NERC may want us to include more about the control logic bus transfer timing.

In doing so, we're going to be treating the grid as a finite supply, not an infinite supply. That's largely different from how the nuclear plant does their analysis.

Next slide, please.

What Nerc does is they do wide area, regional, interregional power flow, which are load and voltage studies and dynamic analysis, such as transient dynamic stability studies, and these get rolled up into summer, annual, ten-year reliability studies, and they're very broad studies, and they're looking at the future. Everything the NRC has been doing we've been looking at the past and they're trying to look ahead.

This is in contrast to the TSOs who are doing in depth studies for their area.

The basic idea is that once the nuclear power plants are modeled in sufficient detail, the NERC studies will provide regular screening assessment of the NPP and the grid conditions, and these screening analyses provide a test of the capability and reliability of the off-site power system to insure its availability.

And I listed a few of the items here that we can get feedback on from the NERC studies. They have a whole list of things that they get from these things as they're doing it.

In particular, the last bullet, you know, as these studies are done and the models are passed around, there's going to be an increased level of awareness from the transmission systems and the operators about the nuclear power plant constraints and the critical points that need to be monitored effectively.

One thing NERC wanted to do in the study was that some plants have local voltage control, such as tap changers, but most of them don't. So that basically what you see is what you get, and the actual voltage adjustment comes from someplace else in the grid, and they want to understand where those critical points are and that NERC has an effort internally to identify significantly operational circuits. The flow gates or nodes in the bridge that you've got to control or have available the most --

MR. SIEBER: Well, the system operator --

MR. RAUGHLEY: -- to help control the grid.

MR. SIEBER: -- one of his major responsibilities is to adjust the voltages to keep reactive power at a level that you don't burn the lines down and trip out transmission lines or substation breakers.

So the voltage that he may require on different generating units may be different than what would be the optimum voltage for a nuclear power plant sitting on that same grid.

So I guess all I'm saying is it's not that easy a problem.

MR. RAUGHLEY: No, no, and you've got to work it out on paper ahead of time. It all gets into understanding the grid is a function of how much analysis you do to understand how it's going to behave under different conditions, and once you understand the conditions that are adverse, you stay away from them.

MR. SIEBER: Right.

MR. RAUGHLEY: The last slide.

Some of the benefits of this is this is a way to study and predict and monitor grid health. It's a way to capture and assess all of the changes going on. About this time last year I talked to you about changes in the transmission loading. We saw the relief requests mounting. You would be able to study a Calloway type event.

We've got the summertime phenomenon with the more effect of the grid on the nuclear power plants in the summer, and we've got the overall frequency of a loop decreasing, but importantly the NRC studies show that the probability of a loop giving a reactor trip is increasing, that that's caught NERC's attention, and they're interested in where, and this allows to investigate why.

FERC, as part of their new routine, they've required the reporting of different planning, bounding, planning and operational studies, and they recently made us aware that some nuclear generators are operating at very low power factors. So that would be a very high bar, low megawatt to boost the voltage in the area.

Under those conditions you might get a different voltage. You get more of a voltage drop following the reactor trip than you would at a higher or normal power factor, but at the same time it provides for a more stable system.

The other end of the spectrum you'd want to investigate where you have the reactor power up rates, where we're operating the reactors at a higher power factor, which is a lower VAR supply to the system, and under those conditions you'd get less of a voltage drop, but that tends to destabilize the system.

MR. SIEBER: Yeah, generally though the nukes have a lower fuel cost. So they try to get as much horsepower into it, which is real megawatts as opposed to VARs.

MR. RAUGHLEY: So just to give us a way to plug what's going on into and get some understanding of whether the stuff is truly random or whether it can be explained.

MR. SIEBER: Right.

MR. RAUGHLEY: We'll get other insights where we could substantially reduce the impact of the grid on the NRPs.

Another thing we're doing is identifying grid and nuclear plant group behavior, signatures and patterns under normal and less than ideal conditions. For example, we've gone through and looked at the loop history from 1965. Forty percent of the plants have never had a loop at power or shutdown. So you get into what's going on here. You know, you have the Morro Bay. There might be some where you have multiple units connected to a common switchyard, where Morro Bay was -- every time a unit would trip there, you'd get a momentary loop at the Aldo (phonetic), and they made some fairly significant changes in grid operation and in the plant design to work around that. so there are some lessons learned there.

So I think this provides a platform to really start to investigate things electrically.

MR. SIEBER: Okay.

MR. RAUGHLEY: And we're just getting started on it. It will probably be the better part of a year and a half, two years to get all of this stuff plugged in if you're doing it in steps.

MR. SIEBER: I think one to two years, if you can do it in that amount of time, you will be lucky. You know, it's very complex and it's a lot of work.

MR. RAUGHLEY: Okay. If there are any questions.

DR. KRESS: I didn't see anywhere in the generic letter -- maybe I missed it -- a good definition of what's meant by grid risk sensitive. Could you expand on that just a little for me?

MR. RAUGHLEY: That was, I guess, Slide -- we added that term to clarify in the maintenance rule area. This is Slide 14.

DR. KRESS: Slide 14?

MR. RAUGHLEY: Yes.

DR. KRESS: Yeah, I saw that, but --

MR. RAUGHLEY: In response to the comments to try to clarify what exactly are we concerned about when you're talking about maintenance of risk significant components, those that can cause a plant trip, those that can cause a loss of off-site power or loop, the equipment that can affect the ability to deal with a station blackout.

DR. KRESS: But did you define these terms, "high likelihood"?

MR. RAUGHLEY: No, we didn't define them.

DR. KRESS: Just leaving that up to the operator to decide?

MR. RAUGHLEY: Well, you have PRA studies that have been done, and certainly if you're talking about the configuration risk management programs that exist in many plants, they already know what equipment is risk significant, and per the implementation of maintenance rule, that's also part of something. They would define what risk significant means for that plant.

DR. KRESS: Normally they just assume the normal frequency of a loop in deciding risk significance of the things that they have got in maintenance. So now you're asking them to do a conditional given the loss of off-site power?

MR. RAUGHLEY: I think there's a maintenance rule that's saying that before you enter into an evolution that you look at the risk before taking that equipment, risk significant equipment out.

DR. KRESS: Yes, I understand that. I mean, it's already required by the maintenance rule.

MR. RAUGHLEY: Right, and what we're asking is --

DR. KRESS: Are you asking for something more here?

MR. RAUGHLEY: Well, what we're asking is does your evaluation that you're doing include the risk from the grid as part of what you normally would do.

DR. KRESS: Oh, you think it might not?

MR. RAUGHLEY: Yeah, yeah. We think it might not.

DR. KRESS: I would assume it did.

MR. SIEBER: Well, the grid risk goes up and down as conditions change on the grid. When you do a maintenance rule assessed with what the risk is, you put in a single number for grid reliability, and that's what they're saying. Don't do that anymore. Put a better number in for grid reliability.

DR. KRESS: A real time number in?

MR. SIEBER: Yeah, something like a prediction.

MR. JENKINS: Well, we're trying to ascertain exactly what they're doing, and not pre --

DR. KRESS: You just want to know what they're doing.

MR. RAUGHLEY: We just want to know what they're doing, and we can assess what they're doing to see if that creates a problem.

CHAIRPERSON WALLIS: Well, your difficulty comes, as I've said before -- you can get all of these answers. You're going to have a real task to figure out how to make a decision based on all of this tremendous multiplicity of answers you're going to get.

MR. SIEBER: Well, you're going to get a different answer for every power plant.

DR. DENNING: I'd like to ask a question of where does it go from here then because as I look at this, it certainly looks like an escalation in requirements is implicit in the letter, and I think that's one of the things clearly that is an industry concern. It's not just you're asking question. There are some statements made about the interpretation of what your assessment of functionability means, and those are different from historically what people have interpreted that.

And certainly at the time that the GDC was put into effect, there was no concept of NRTCA. So the question is where does this really lead to. Is it a rulemaking eventually or is it just regulatory? I don't understand where it goes, how it impacts back then on the utility perhaps in changes in technical specifications. So where does it go?

MR. JENKINS: Once we have the information, we'll assess the information not only in terms of based on the information we've gotten from NERC, FERC, the temporary instructions. We'll also be looking in terms of their licensing basis, and obviously we can't make changes unless you go through the backfit process or we talk about rulemaking.

And certainly we're not at that point now. The implications you may be reading in there is that this is staff's expectations of where we are in this particular point in time. If you look at the FSAR, Chapter 8, there were grid studies performed when they were licensed. So this is not something that's new. What we are saying is that there have been dramatic changes with respect to that relationship between the nuclear power plant and the transmission system operator, and we're trying to understand exactly what is going on.

And in each case, it may be a different answer depending on that licensee. We certainly are not going to make any changes that will make the situation worse. So we're trying to understand what exactly is going on and how going forward safety is maintained.

So we're not in any sense trying to imply that licensees adopt the interpretation in the generic letter. In the regulatory information summary of 2004-05, we spelled out these same expectations that you read in the generic letter. We said, okay, this is, given this current environment, what we would expect licensees to do with respect to the regulations that exist now.

We could very well get answers back saying, well, that's not our interpretation of the requirement.

Jose.

MR. CALVO: Yes. I'm the former Branch Chief of the Electrical Instrumentation and Control Branch. So treat me with dignity.

You're asking a good question, and you're right. It's a monumental task to analyze all of these questions, all of these responses to these questions.

Twenty years ago when we accepted the designs, it was based in achieving a reasonable assurance that a combination of the off site with the on site, and we also thought that the off site was the preferred power supply. The on site, this was used there for back-up and only for back-up purpose.

So the focus, we want to be sure that that focus is still there. We're in the 21st Century. The electrical utility industry has deregulated not all the places, mostly in the Northeast and the Midwest, and we would just like to know is that reasonable assurance still there.

It is the combination of the off site and the on site, the on site being preferred, okay, and that's what we're trying to determine.

Now, we end up doing nothing or we end up going to rulemaking. I think things today the GDC can be interpreted many ways. It has been confused, and it is confused now because the staff wants it. I was here when that thing was written. It was done that way to provide the flexibility that the designer would like to have when you implemented this on-site power system.

Now we're getting into trouble with that because now the grid is not being operated in the way that is envisioned 20 years ago. Now we're in the 21st Century. Things are different, and all the staff is trying to do is to find out how things are today.

Maybe the regulations have to be rewritten or maybe nothing is to be done.

Maybe there's a degree of awareness that the fact that we're getting involved with the thing if fine. We've done level samplings, by going to different plants through the TIs, and we find out that although everybody understands, the right people aren't now aware of it. Okay? So somebody in the organization knows about the thing, but the operator who is responsible on a day-to-day thing is not.

So all we're trying to do is collect information. Everybody thinks the same thing you think. (Unintelligible.) We're not there yet, and we can't tell you what is going to happen. It is going to be a monumental task. The staff is going to have to evaluate all of the things up, come back and talk to you buys and see how together, how we can move ahead. That's what we're trying to do.

And I guess Raughley is giving you a little touch of what is it for research, what we're doing into the future. See, we're looking at the pressure situation. He's looking into the long-term situation. How do things -- by the time we decide what we're going to do, hoping that we come together in FERC, that they come up with something that will help us towards.

You know, FERC is building an organization over there, and it's not there quite yet, but the time will come. All of these will come together, and working together with the industry, working with FERC, I think we can come out with an assurance, a reasonable assurance, that in this new world of the 21st Century with electrical power, that, yes, the nuclear power plants continue to be safe, and that's what we're trying to do.

And I'm signing off for a former Branch Chief.

(Laughter.)

MR. SIEBER: Well, do the members have any additional questions they'd like to ask?

DR. POWERS: The whole thing has the aura of a fishing expedition to it, and I can understand this argument that says, gee, things have changed a lot from when the FSAR was written. Now, of course, there should be updates to that FSAR on a two-year basis. So I'm not sure why it's so terribly out of date.

But let me get to the heart of the question, which is we're going to collect this information together and try to understand what it all means, and then you're going to decide on a course of action. Surely you must have thought what your course of action is at least for some of these anecdotal situations which you know about.

Can you tell us about those?

MR. JENKINS: You mean situations we have run into as far as --

DR. POWERS: Yeah, run into a few of them, enough to elicit your interest in this whole area.

MR. JENKINS: Well, you know, the Calloway 1999 event in which the plant discovered that, in fact, due to these power flows going across their area they would have had inadequate voltages had the unit tripped, and that was really the first time that we really had evidence that these external conditions were affecting a plant.

And we have had I guess we call it observations from the TI, from the temporary instruction, that have indicated that in some cases, you know, operators may not be aware of what the actual conditions are.

If you're talking about in the maintenance rule, it's not clear whether there's a consistent basis for using grid information. Those are the kinds of things that we've been seeing as far as the temporary instruction.

There are a number of different kinds of observations.

Tom.

MR. KOSHY: One other example is when -- this is Thomas Koshy from Electrical Engineering Branch.

When there is significant work going on in the switchyard, if the nuclear station is not aware of what happens in the nearest switchyard, they will very well be taking the emergency diesel generator out for a 14-day maintenance.

So if this communication is not there, usually the switchyard work is one of the leading causes for multiple unit outage. In fact, we already had those, and they were working in the switchyard.

So what we are saying is communicate with this outside agency, which is now independent, under a different organization, so that when there is a high vulnerability for a plant to trip off, your on-site sources are kept ready and not in maintenance outages that you can reach out for.

So these are the kind of examples. You know, this is actually what I discuss in a working group where we heard currently there is no such coordination work.

DR. POWERS: Well, I think I understand what the concern is. What I'm asking about is what are you going to do about it. I mean, I understand you can collect all of this information, but I'm asking you surely have thought what you're going to do about it in some limiting cases.

MR. KOSHY: What we have now found out is the TIs and the information that we have put out have given enough reasons for the working group to discuss the subject, and we have sensitized the industry.

But what we're also finding is some of them are still reluctant to accept it as, you know, something undecided and they don't want to do.

We have some very good, shining examples from certain plants actually in the Chicago area when the grid voltages is considered unavailable. They have found a way that they can trip off one of the service water pumps and thus the plant load will be such that they can live with the voltage that is available.

So industry is finding creative ways to solve this problem, but what we have done so far has helped to build the awareness in a way that they're prepared to deal with it, and they interact with the outside agency to just consider it foreign, and now they have a working arrangement to share with each other the vulnerabilities on either side and be prepared to deal with it.

The bottom line is that from this information we come to the conclusion that they're not in compliance with the regulations, we'll take the appropriate action based on that.

We're nowhere near that point, but that would be the offshoot of getting information in the case that you have a safety issue. We will work through that process to determine whether or not we need to take any enforcement action.

MR. SIEBER: I don't want to limit questions, but I sort of have to do that to give Mr. Alex Marion from NEI an opportunity to say a few words on behalf of the industry.

MR. MARION: Good morning. My name is Alex Marion. I'm Senior Director of Engineering at NEI.

I want to thank you for the opportunity to make a few comments, and I do recognize I'm between you and lunch. So I'll try to be as brief as I possibly can.

On June 13th, NEI submitted comments on

the proposed generic letter on behalf of industry. I'd like to ask. I'm assuming that you all have reviewed those comments, and I'd like to take a minute and ask if any of you have any questions about any specific comments that we had submitted.

(No response.)

MR. MARION: Okay. We truly believe it is appropriate for the NRC to request information, but that information has to be bounded by information the NRC needs to have to assess compliance with an existing regulation, and that boundary condition is established by the current plant licensing basis.

That's fundamentally the regulatory framework, if you will, for requests for information. More importantly, I found the discussion this morning extremely interesting because the NRC is requesting the information under the provisions of 10 CFR 50.54(f), which says NRC needs this information so they could make a determination of what action needs to be taken on the status of the operating license of that facility.

I have yet to hear that there's a safety concern. I have yet to hear that there is a direct, straightforward compliance concern. So, therefore, the whole concept that NRC is pursuing here, I think, is questionable.

Extensive efforts have been taken within the industry, and when I'm talking about the industry in this context, it's the transmission industry as well as the generation industry, as well as the supply and distribution. A tremendous amount of efforts involving FERC, Federal Energy Regulatory Commission, and North American Electrical Liability Council, the regional councils, the utility service commissions, the utilities that are vertically aligned, the entities that are responsible for transmission, maintenance and operation, et cetera, to improve the grid.

This has been reinforce with the energy legislation that Dr. Sieber referred to that was passed by Congress that establishes standards, and those standards will be enforced, and they will be complied with, and there are discussions right now between NERC and FERC to determine the extent of financial penalty that will be used.

The standards, by the way, are already in place. They've been developed by NERC. They're officially going to be enforceable with this action of the notice of proposed rulemaking that was referred to earlier.

The U.S.-Canada Power System Outage Task Force that investigated the August 14th, 2003 event was very clear in capturing the extent to which nuclear power plants responded to the event. They responded in a manner in which they were designed to protect public health and safety. They also responded in a manner consistent with NRC regulations.

Since that time we have been struggling on behalf of the industry in trying to figure out what problem the NRC is trying to solve. It's still not clear. We do recognize that it's extremely important for effective interaction and communication between the nuclear plant owner-operators as generators and the transmission service operators and other entities that deal with the transmission side.

Efforts are underway to improve that process. There's a NERC standard under development. We referred to that in our comments. There has also been action taken by INPO to make sure that that is well established and in place, and efforts are underway to do that.

I do want to make a couple of comments relative to statements that were made in a briefing this morning. There was a statement made by Mr. Sieber relative to a utility taking a diesel out of service in light of a hurricane approaching. Let me give you some details on what happened there.

The plant had scheduled I think it was a ten, 12-day maintenance outage on the diesel generator. They began that outage the first day of August. Okay? They completed that work or that evolution, if you will, on the diesel, restored it back into service about the 11th, 12th of August, some time around there.

Hurricane Katrina didn't hit until the end of the month. There's a two-week lag. So there have been statements that have been made by NRC senior management that a utility took a diesel out of service as a hurricane was approaching landfall, and that is absolutely unequivocally not true.

With regard to the maintenance rule, it's very clear that the utilities have the responsibility to assess and manage risk associated with maintenance. There's no question about that.

What the NRC is doing at this particular point is second guessing how the utilities are doing that. In each of the cases that I'm aware of, the case of Hurricane Katrina and that plant and the case of San Onofre relative to the August 14th distribution line outage, et cetera, the risk assessment evaluated the condition of the grid over that period of time. It evaluated the susceptibility of having problems on the grid that may affect the plant, and they did the necessary risk analysis and the requirements of the regulation and requirements of the threshold and reg. guide -- not the requirements -- the guidance of the threshold in Reg. Guide 1.74 were satisfied.

So the evaluations are being conducted. The concern appears to be one of there's a perception that the grid is more susceptible to disturbance in the summer. We have yet to see data that validates that.

At a public meeting last week with Southern California Edison, representatives from the California independent system operator as well as representatives from Southern California Edison organization responsible for the control center and transmission operations indicated as well that they haven't seen any data that suggests that to be the case.

I was at the offices of the North American Electric Liability Council yesterday, and I posed the question to some of their staff. Their response was that they haven't seen any data to indicate that's the case.

If the NRC has any data, we would like to engage them in a public meeting and let's resolve that question once and for all.

I think it was Mr. Gill's presentation. He suggested that there's a question of concern on the part of the NRC associated with plants that exist or that operate in a deregulated environment. I can appreciate the concern, but we're not aware of any data that indicates that there is a demonstrated concern that there are different, unique problems for generators in a regulated versus a deregulated environment.

If the staff has such information, I would ask them to make it publicly available.

Just one final comment regarding Mr. Raughley's presentation on the Office of Research activities. That's interesting stuff, looking at transmission system operation analysis, power flows, dynamic analyses and modeling of them.

The electric transmission utility industry has been doing that for years. They will continue to do that into the future. The question I pose is why is NRC looking into that.

Those kinds of analyses have nothing to do with regulating nuclear power plants, and with that,

that completes my comments, and I thank you for the opportunity. I'll be more than happy to answer any questions you may have.

DR. POWERS: Mr. Marion, I was struggling with the same issue you opened with, with what is the regulatory issue, and the perception I got out of the presentations was that this was one of the -- the concern was over the maintenance rule and whether adequate risk planning was being done in carrying out various kinds of maintenance, notably diesel generators, but I got the impression there were other things as well.

Is that your impression here?

MR. MARION: That's one of the concerns that I understand or one of the areas that the NRC is looking into, and it really gets down to what considerations do you take into place when you do your risk assessment as required by the maintenance rule.

And I have to tell you -- and I haven't spoken with all of the utilities that have done these assessments this summer, but a couple of the ones that have been identified, for example, the plant that was involved with Hurricane Katrina and the diesel, they did their assessment. Their assessment was independently validated by the region, and so we look at that and say, "Well, what is the issue? What is it that we need to make adjustments on? What do we need to change?"

We're still struggling with that as an industry, and individual plants are struggling with that in terms of trying to understand NRC expectations.

DR. POWERS: But I think the essential point here is that these maintenance decisions do get audited at least --

MR. MARION: Oh, absolutely.

DR. POWERS: -- and looked at very carefully. So the question comes up: what are we looking at more here?

MR. MARION: If I knew, I would tell you. Really, we're struggling with this. We became actively involved after the August 14th, 2003 event and I'm proud to say that NERC has been involved, North American Electric Liability Council and all of the meetings we've had with an industry task force, and one of the focus areas is try to understand what the NRC concerns are so that we can be responsive to those concerns and address them as best as we can.

And we are still going on to three years later, still struggling with trying to identify the problem.

DR. DENNING: There's another element here, Dana, that it seemed to me and that's related to the RTCAs and whether plants are currently doing that type of analysis and whether they are making decisions that would require a shutdown of the plant based upon those decisions.

Is that your interpretation as part of --

MR. SIEBER: That's going through the analysis.

MR. MARION: As I understand it, and I would ask the NRC to clarify my understanding, please, the NRC expects the utility licensee responsible for operation of the nuclear power plant to have sufficient information relative to the output of these real time contingency analyses. Okay?

The problem is that the utility owner-operator is not responsible for any aspect of that analysis. The transmission system operator is responsible for that analysis. The transmission system operator, when they identify a vulnerability that may exist as a result of running the computer model or doing a bounding analysis, they communicate that information throughout the transmission industry to the extent it affects the power plant.

They will communicate that to the nuclear plants as well as the non-nuclear plants. So the process is in place.

The question is how far do you take it, and our argument is that the utility owner-operator should be aware of the conditions on the grid. The responsibility of communicating the information of the conditions on the grid rest with the transmission organization. All right? And as long as that protocol is in place, the information is being exchanged and appropriate action is being taken.

And at a public meeting last week with Southern California Edison, I referred to earlier that there was a representative from the California independent system operator as well as the Southern California Edison transmission organization, as well as the plant, and they discussed the August 25th line outage, August 24th. I forget the date, but some time in August of this year, and they clearly demonstrated the extent of communications and the actions that were taken by each of those players involved in the transmission operation, as well as the nuclear power plant.

MR. JENKINS: In reference to that meeting, the licensee requested that they come in and talk to us to clarify exactly what went on, and when we get their letter we'll certainly assess the actions that were taken there.

Getting to your question, the use of tools, state-of-the-art tools is not unusual to refer to these tools when you're talking about how do you arrive at a given assessment, and so the generic letter does not require nuclear power plant operators to use the tool.

MR. SIEBER: They can't.

MR. JENKINS: What we're trying to do is to say, okay, are you aware of the use of these tools and how not using these tools may, in fact, identify whether or not the transmission system operator is keeping the system updated properly that you are relying on.

You're relying on the transmission system operator to tell you that, in fact, All State Power is operable, and if they are using an analysis that is out of date or not current to actual conditions, then you have a responsibility to be aware of that, to work with the transmission system operator to make sure that they have the best tools that's possible such that if there is a situation that comes around where the grid operations are outside the bounds of that analysis, you will be aware of it.

So it's more of an awareness. The purpose of it is not to imply any requirements, but to talk about awareness.

yes?

MR. SIEBER: And just to wind it up, but at the same time I think I have to make a comment here. It would appear that the nuclear power plant operator is supposed to know what tools the transmission system operator is using, whether they are up to date, when the analysis is performed. I think that really goes well beyond what the nuclear plant operator is required to do.

MR. JENKINS: Jose.

MR. CALVO: Let me put it in perspective. We said that we don't know what we ask in these questions. There's no connection that could be made that we needed the regulation.

Those tools, it's not the tools that are important. We want to be sure that the operator knows that he's meeting the regulations. Why are we worrying about those tolls? Because the operator -- a nuclear power plant must meet the first contingency, meaning that if I lost the nuclear power plant, okay, I must have assurance that the availability of said power would prevail. All right?

So that's the reason for those tools. So how did the -- the operator is aware that the operator is providing the right kind of information, and then we're getting into the tools. Okay? We're trying to verify based on where.

If you want to remember anything about the grid, one thing that is immediately it continues to meeting our regulations. How do we know that to be the first contingency? It's by knowing that if the tools are in place, then it assures them that the grid is being managed in such a manner that if I lose that local unit, okay, the GDC-17 says you minimize the probability or loosen the capability of off-site power to the emergency buses.

That's what we ask of those tools. We're not there fishing on the grid. We were here at the nuclear power plant worrying about safety, okay, and we've got regulations in place, and I think Mr. Marion here, Alex, is making a good point, making that he's confused and we also are to confused. So we are confused. What is wrong getting that information so we can determine what is the next step to go in the future so that we will get de-confused? Okay?

I think he is just making a point for us in there.

MR. SIEBER: Well, sine we're all now in agreement, I would point out that we have chores that we have to do during lunch hour, and so our actual time to eat is really disappearing.

So I would like to thank everyone for the presentations and the effort that they went through, and we will be sure to send you a letter.

Thank you very much. Mr. Chairman.

CHAIRPERSON WALLIS: Thank you.

Now, before we adjourn for lunch, we are behind. We have interviews, and I would like to allow the committee a chance to at least get a sandwich or something. So we will not start the next session until one o'clock.

(Whereupon, at 11:56 a.m., the meeting was recessed for lunch, to reconvene at 1:00 p.m., the same day.)

AFTERNOON SESSION

(1:03 p.m.)

CHAIRPERSON WALLIS: I'm looking forward to hearing about the ESBWR. My colleague Tom Kress will take over from me for that purpose.

Tom.

DR. KRESS: Thank you, Mr. Chairman.

This is just an information briefing for us. I think we'll learn more about the design and the safety features of the ESBWR. It's now very important for us to follow this because they have to come in with an application for certification. The staff has gone back and asked for more information, more details, but it's serious now, and we want to really take a look at it.

I think later on we'll have meetings on probably the PWR, probably the thermal hydraulic aspects of the Chapter 15 stuff, but we don't expect to have a letter. This is mostly for us to be sure we're up to speed on what the ESBWR design is and what kind of safety features and redundance and diversity it has.

Those of you that like acid systems ought to really love this one.

CHAIRPERSON WALLIS: We've heard about

this before.

DR. KRESS: Yeah, we've had discussions on it before, but now we've got to really think about it because --

CHAIRPERSON WALLIS: Got some more detail this time?

DR. KRESS: Yeah, more detail. We are going to be faced with the certification, and so we want to be sure we are up to speed again.

So with that I guess I'll turn it over to Amy Cubbage of the staff to lead us on.

MS. CUBBAGE: Yes. Amy Cubbage. I'm a Senior Project Manager in the New Reactor Licensing Branch, and I'm a lead project manager on the ESBWR design certification review.

Larry Rossbach is here. He's also one of the project managers and we'll be adding to our team very soon because the work is pretty heavy.

I just wanted to go over briefly. As you mentioned, we've been here before to talk about the ESBWR. In July '03 we briefed the Thermal Hydraulic Subcommittee and again in January 2004 and then February 2004 we went to the full committee and the subject there was the Track G LOCA review, and we received a letter from the ACRS in February 2004 and subsequently we issued a safety evaluation report approving the application of Track G for ESBWR LOCA.

I just wanted to take a minute to go over the project overview. We're doing things a little bit differently this time rather than the way we did things on AP-1000, and the key difference here is rather than a DSER, we're issuing a safety valuation report with open items, and that safety valuation report will have more review finality that we have previously so that when we go to the final stage, rather than reissuing another 2,500 page document and having to go through it all again from front to back, we're going to address the open issues and supplemental SERs, one or multiple depending on the timing of the closure of the open issues.

I think this may impact our interaction with you regarding when we would expect letters and to be reaching closure on issues, our goal with this review is to identify issues and resolve them as early as possible, and so to that extent we hope that we can get issues on the table that you may have as early as possible in order to allow time to resolve them.

DR. KRESS: Well, we'd normally try to write an interim letter when we have issues. I don't know that this is the time yet, but --

MS. CUBBAGE: No, this would not be the time, but I think what we're getting at is previously with the DSER there was always the expectation that everyone would get another bite at the apple, and in this case we want to reach a level of finality with that SER with open items, and hopefully address any concerns that you may have at that time with the issues that the staff has reached closure on, and then move forward into more of a strictly open issue resolution mode with the final.

CHAIRPERSON WALLIS: And what we've had so far and it looks like what we're going to get today is a lot of descriptive material, and some time we're going to get some numbers, are we, and something --

MS. CUBBAGE: Well, you all should have received a copy of the Rev. O application. That plus the PRA is about 7,600 pages of information, and so this is a short overview session here for the full committee.

CHAIRPERSON WALLIS: But it points us at places we should read in this huge piece of document?

MS. CUBBAGE: Well, I expect that we'll be coming back for much more detailed sessions, and we're already talking with your staff about a subcommittee meeting on PRA severe accidents.

CHAIRPERSON WALLIS: But when we get these enormous documents, it helps if someone can say, "Well, these are the areas where you really should focus" because that's where the issues are.

MS. CUBBAGE: Well, yeah. We're not quite at the point where we can --

CHAIRPERSON WALLIS: Not at that point yet?

MS. CUBBAGE: -- point you in that area.

And then I just wanted to point out to you that the nominal duration for design certification review, including rulemaking is 42 to 60 months. We have not yet set a specific schedule for the ESBWR review pending resolution of the acceptance review issues.

So the application was submitted in late August. We sent a letter in late September to GE requesting more information before the staff could formally accept the application for docketing. GE to date has responded to all of those issues. They provided several submittals including multiple topical reports.

We're currently reviewing those submittals for acceptance, and we expect to communicate the results to GE by the end of this month.

And that's all I have. I'd like to introduce David Hinds to make the presentation for GE.

DR. DENNING: Could I ask a question before we move on to that?

MS. CUBBAGE: Sure.

DR. DENNING: And that is obviously in an open meeting we can't talk about security related elements.

MS. CUBBAGE: That's right.

DR. DENNING: But at some time I think we would be very interested in that, and I'm particularly curious about just the process at this point and how much effort is spent and what the criteria are that would be used in that review, and then I'm not sure whether this belongs in Tom's subcommittee or Mario's on security, but I guess I'm just curious.

MS. CUBBAGE: Right.

DR. DENNING: When would we get a chance to see those types of considerations?

MS. CUBBAGE: We would anticipate having interactions with you on those as we would with any other of the issues in the application. To date they have submitted a safeguard submittal that provides some information about how their design complies with existing requirements and the revised DBT and ICMs.

We've also issued a SECY paper recently, SECY 05120, which is specifically related to new reactor licensing security issues, and we have an effort underway to begin defining what criteria we would use in those areas.

So we're in a process there where we don't have set criteria yet.

DR. DENNING: Thank you.

MS. CUBBAGE: Okay.

MR. HINDS: Okay. Good afternoon. I'm David Hinds. I'm the General Electric engineering manager for the ESBWR project, and I'm accompanied here with Alan Beard and Rick Wachowiak on our team.

I'll be handing off during the presentation to those gentlemen.

We have here today basically an overview, no specific targeted segment of ESBWR, but came in with an overview to give you, I guess, a first glimpse of the ESBWR, an overview of the signed certification status, which Amy has already given you a little bit of information.

As far as go through a little bit of design evolution of the BWR, the primary characteristics, design improvements, a little bit of detail of the passive safety systems, and then we have with Rick Wachowiak a discussion of the PRA.

Okay. The ESBWR basically builds on the ABWR certified design. I currently have ABWR projects overseas which the Lungman project currently in progress. We have a team in place to support the Lungman, using that experience base within GE to help advance --

CHAIRPERSON WALLIS: Where is Lungman?

MR. HINDS: Lungman? That's in Taiwan.

CHAIRPERSON WALLIS: It's Taiwan?

MR. HINDS: Yes, sir. So using the team --

DR. BONACA: And you're building an ABWR in Taiwan?

MR. HINDS: Yes, in Lungman. That's correct.

DR. SHACK: How many do you have operating in Japan?

MR. HINDS: Let's see. I believe it's three.

PARTICIPANT: Three in operation and two under construction.

MR. HINDS: Okay. So anyway, using some of the technology from ABWR and advancing it forward, the passive safety systems are new. So we have built on some experience there as far as our suppliers, as far as our technology, and we plan to continue to move that forward. ESBWR is the product where we're doing that.

We submitted the DCD as I mentioned before in August. It's using standard reg. guide format, and it's also reliant upon I mentioned the technology of the ABWR, but we also have technology from SBWR.

I've got a little slide coming up here which will help. I give a little graphic of that.

We also have been watching the AP-1000 certification efforts in order to learn lessons from the industry in that regard as well, in areas like, for instance, main control room habitability, witness to regulatory treatment of non-safety systems, diverse digital C&I. We're learning from the industry as well.

DR. KRESS: Is C&I the same thing as I&C?

MR. HINDS: It is.

(Laughter.)

MR. HINDS: I&C, C&I, sure, the same thing. Control and instrumentation or instrumentation and control.

The NRC initiated prompt review once we submitted the DCD, and we've had a great deal of communication and questions, and we have been providing additional information for clarification as well as additional technical submittals based upon those interactions.

We have received an acceptance review letter from the NRC that in identified areas requiring further information and, as mentioned previously, we have responded to that and provided additional information.

We also came up and had a multi-day session with the staff in order to give a communication from our technical leads to the review staff in order to provide detailed technical information in a verbal setting and allow some interaction in a question and answer to get the review started.

This will just real briefly mention about BWR evolution. The early BWR began in Dresden with steam generators and steam drum there. Moving over to the multi-loop steam generators with no steam drum, and then on to the -- and you can see the Oyster Creek there with the recirc. loops, and then moving into Dresden with recirc. loops with jet pumps.

Then that evolved further into the ABWR, which does not have recirc. loops, but does have recirc. pumps there at the bottom head area.

Then the evolution where we currently are is into the natural circulation, which began with the SBWR. SBWR did not -- began the certification process, but did not complete it. It was not commercially feasible at the time based upon the economics. So we withdrew that effort, and then advanced that technology forward to the ESBWR, which is similar but a larger reactor.

And just real briefly, on the containment evolution, beginning in the early stages with the dry containment, moving to the pressure suppression type containment, then on to the Mark III style containment. The containment has been also evolving all the way up to the SBWR and ESBWR, which has elevated suppression pools. You can see down at the bottom portion of your slide elevated suppression pools and then elevated GDCS tanks, which we'll give you much more detail later on in the presentation as far as the passive safety injection systems, which take advantage of the height difference.

DR. KRESS: That's the spent fuel pool off to the side there?

MR. HINDS: Yes, sir. Over in the ESBWR that's the spent fuel pool down at grade elevation there. So that was another change from SBWR to ESBWR, is bringing the fuel pool down to grade elevation.

One of the other requirements -- yes, sir.

DR. KRESS: Is that line that goes around, is that the containment, confinement? I mean, is the spent fuel pool inside or outside the containment?

MR. HINDS: It's outside.

CHAIRPERSON WALLIS: It's outside. t Eh containment is that heavier line inside.

DR. KRESS: It's the heavier line, yeah.

MR. HINDS: Right. Yes, heavier line and then comes underneath the reactor vessel.

CHAIRPERSON WALLIS: I think it's that dome above the reactor there, the little cap thing above there.

DR. KRESS: Yes.

MR. HINDS: Yeah, containment --

CHAIRPERSON WALLIS: It's that thing, right.

MR. HINDS: -- would be in this. This would be our containment down there.

Okay. As far as EPRI produced the utility requirements document, and just a real high level overview indicating that we do meet those requirements and then some, at least in these areas mentioned here.

The tornado, 330 miles per hour rating, extreme winds, 140, temperature bounds the ESP sites that we currently have, and seismic meets the Reg. Guide 1.60 plus a central U.S. hard rock site.

CHAIRPERSON WALLIS: So we can't debate these extreme winds. That's something someone has already decided?

MR. HINDS: I'm sorry. I couldn't hear.

CHAIRPERSON WALLIS: There's one 40 miles per hour that's already decided by somebody else. It's not available.

MR. HINDS: That was what we incorporated into the design.

CHAIRPERSON WALLIS: You did it or was it required by the agency?

MR. HINDS: It was the EPRI utility requirements document has a number. I believe it's 125, and we designed above that to 140. Alan, if you know the exact number, you can.

MR. BEARD: One, twenty-two.

MR. HINDS: One, twenty-two? Okay. That's what the EPRI requirement was when we designed in excess of that, and that was the number that we chose.

CHAIRPERSON WALLIS: But it's quite clear that Category 5 hurricanes go above that.

But anyway, let's move on.

MR. HINDS: Yes, I understand.

Okay. This is not very easy on the eye, but just to give you a --I've got another slide that --

CHAIRPERSON WALLIS: It's impossible on the eye.

MR. HINDS: This is just to show you a little bit of the site layout of the standard reference plan. Right in the center there would be the reactor building.

The next slide has got a --

CHAIRPERSON WALLIS: That little thing is the reactor building.

MR. HINDS: We didn't have the detail slide, but reactor building with control building and turbine building off in this direction, force cooling towers if needed on the site, and we would adjust, if necessary, if it's a multi-unit site.

Okay. Can everybody hear me now? All right.

Okay. Here are some basic parameters of the ESBWR. It's a 4,500 megawatt thermal power with approximately 1,575 megawatts electric gross. Now, of course, I say approximately because that will be dependent upon some site parameters in specific turbine as well as cooling water capacity or cooling water parameters.

It is a natural circulation plant. There are no recirc. pumps, no recirc. loops, and there's passive safety systems, which 72 hour passive capability.

CHAIRPERSON WALLIS: Is this megawatts all out of one turbine? You don't build a turbine that big, do you?

MR. HINDS: We, GE, don't currently. They are made in -- there is a manufacturer that makes them that big, and there are efforts underway for other manufacturers to make one that large, as well.

DR. KRESS: So you envision this would be single loop?

MR. HINDS: Yeah, it's --

DR. KRESS: Going directly to the turbine.

MR. HINDS: That's correct. That's correct.

And then I've got another slide on here that shows the steam cycle. So I'll move on to that, and that might help answer your question.

MR. SIEBER: Do you have active safety

systems?

MR. HINDS: No, sir, it's passive safety. And we have some detailed slides in here that will show you each system by system. So we'll show you those, and this gives you --

DR. KRESS: But you have some active non-safety systems, like the ABWR.

MR. HINDS: That's correct. We have active, non-safety systems, but we don't have -- our safety systems are passive.

CHAIRPERSON WALLIS: There's no back-up that's active? I guess there is, but it's not called safety. Isn't that really what it is, what it amounts to? They're not classified as safety systems, but there are things you can do to augment this.

MR. HINDS: There are things that can improve the situation, but as far as the systems that we credit for safety, they are passive.

CHAIRPERSON WALLIS: When you do your PRA, you only count those ones?

MR. SIEBER: No.

CHAIRPERSON WALLIS: Or do you count the other one, count the other ones that you could use in the PRA?

MR. BEARD: We count both, and there's a

huge difference.

CHAIRPERSON WALLIS: A big difference, right.

MS. CUBBAGE: It's the same approach as with the AP-1000 passive plant design.

MR. HINDS: Yes, and Rick, if you have any further comments on it. We do have some PRA slides in the end, and we do have our PRA expert here. So I didn't want to steal too much of his thunder, but, yes, we credit passive safety systems, and Rick will go through a little more detail in the PRA, if you can hold for a minute on that.

Just an overview here of the plant. As far as the passive safety systems, again, we'll give you more details on them in just a minute in the presentation, but there is a gravity driven cooling system which Alan will be talking about in just a minute.

Of course, the elevated suppression pools, isolation condenser up in this area, and the passive containment cooling system.

As far as the steam plant, you mentioned or you asked about the steam plant. Here's the steam line going to high pressure turbine with three low pressure turbines.

So somewhat a standard steam plant. We do -- our reference design is indicating three low pressure turbines. A couple of differences is a direct contact feedwater heater, a feed pump and booster pump coupled together.

Other differences from past designs, reactor water clean-up and shutdown cooling combined into one non-safety system, and that might go a little bit towards answering one of your questions a minute ago.

Fuel in auxiliary pool cooling system which has quite a number of functions here, moving water as well as purification. Standby liquid control which is also passive, which has a pressurized tank here to inject our standby liquid control system.

And a control rod drive system similar to past BWR designs, but there are some additional features as far as injection capability, and that also might answer a little bit of the question as to injection capability. So that's another non-safety system that we have the ability to inject with.

And standard hydraulic control units but define motion control rod drives as opposed to past BWRs. In this country at least, ABWR has used defined motion control rod drive.

CHAIRPERSON WALLIS: Would you take your laser and go around what you call containment in this for us again so that we'll know exactly what that is?

MR. HINDS: Okay, all right. Let's see.

CHAIRPERSON WALLIS: Up there and around. so it contains those pools, but it doesn't contain those upper pools.

MR. HINDS: That's correct. It contains the --

CHAIRPERSON WALLIS: So the condenser is part of the containment system them. The condenser is part of the --

MR. HINDS: If you're referring to the -- this is the passive containment cooling system, isolation condenser.

CHAIRPERSON WALLIS: The condenser is part of the retainer of fission products in the containment.

MR. HINDS: These are not within containment if that was your question.

CHAIRPERSON WALLIS: No, but they are part of the circuit which sees any fission product. So they must be --

MR. HINDS: Yes.

PARTICIPANT: Primary pressure.

MR. HINDS: Yes.

CHAIRPERSON WALLIS: Primary pressure boundary, right.

MR. HINDS: Excuse me. I'm sorry.

DR. BONACA: This is your container.

MR. HINDS: Yes, that's correct, on the cover of your --

CHAIRPERSON WALLIS: It's not just the primary pressure boundary. It's the containment boundary.

MR. HINDS: This is the isolation condenser, and again we've got some slides that will show more detail on it in a minute, but the isolation condenser sees reactor pressure in this loop here, and the passive containment cooling system sees containment pressure through there.

CHAIRPERSON WALLIS: Yes, right. That's what I mean. Right.

MR. HINDS: Okay. But the external side here, meaning the pool, is not itself within containment.

Okay. Here's some differences. This is comparing ESBWR and ABWR, just to highlight a few. I've already discussed several of them, but there are no recirc systems. There's no recirc system. It's natural circulation in the ESBWR.

On the ABWR we had a high pressure core flooder system, low pressure flooder, and similar to NRHR, similar to previous BWRs, which had high pressure and low pressure systems and residual heat removal.

We now have passive safety systems, and I mentioned the non-safety reactor water clean-up combined with the shutdown cooling system. We don't have any safety grade diesel generators, and we don't have RCIC. We have the isolation condenser serving a similar function to what RCIC did in past plants.

CHAIRPERSON WALLIS: So everything is passive except for long-term cooling you have to have some sort of a circuit that takes heat out.

MR. HINDS: We have the combined reactor water clean-up shutdown cooling system.

CHAIRPERSON WALLIS: Which is active.

MR. HINDS: That is active. That is correct.

CHAIRPERSON WALLIS: It's not like the AP-1000 where you have sort of an air cooled containment.

MR. HINDS: It is not like that, no.

CHAIRPERSON WALLIS: Not like that.

MR. HINDS: And the SLC, there are no

pumps. No pumps any longer in the SLC system. It's basically a pressurized accumulator to inject the standby liquid control system to handle the ATWS.

DR. POWERS: How is that not an operational -- I mean, what's the accumulator set point on it?

MR. HINDS: What's the pressure seen in the accumulator? Let's see. Can you help me out there, Alan?

MR. BEARD: Twenty-two hundred pounds.

MR. HINDS: Twenty-two hundred pounds. So it's a pressurized accumulator.

CHAIRPERSON WALLIS: Pounds per square inch.

DR. POWERS: It's not passively open. It has to be actively opened?

MR. HINDS: It requires a valve to open.

MR. BEARD: Squib.

MR. HINDS: Squib valve.

Here's a couple other -- highlighting some other differences with some numbers here. The power mentioned on the previous slide, 4,500 megawatts thermal, about 1,575 electric.

The reactor vessel is -- I'm sorry? Okay, okay.

PARTICIPANT: I'm converting meters to feet in my head.

MR. HINDS: Yes. The reactor vessel is similar in diameter to or the same in diameter to the ABWR, but it's a taller vessel, and we have a picture of it here in the later slides.

Fuel bundles, more fuel bundles. There's 1,132 fuel bundles.

DR. POWERS: Huge.

MR. HINDS: With it, three meter active fuel height, and the no recirc loops I've mentioned a couple of times.

Control rod drives, of course, more control rod drives with that size of the core, 269 fine motion control rod drives, and we've already talked about the lack of safety system pumps.

And just a quick preview. Again, we have more detailed slides on PRA, but there's a PRA number, 3E minus 8.

DR. POWERS: I'd just love to see the trade study that occurred on this core design.

MR. HINDS: Love?

DR. POWERS: Love to see the trade study on this core design. That would be really interesting. Not important.

MR. HINDS: Okay.

DR. POWERS: But certainly curious.

MR. HINDS: Safety building volume, as we have been able to go back down to a little smaller than ABWR in that we don't have as many active pumps to house.

DR. BONACA: What's the projected cycle length with 1132? I mean, do you have a --

MR. HINDS: It's designed for a two-year cycle.

DR. BONACA: Two-year cycle. That's a lot of bundles.

MR. HINDS: It is. It is.

DR. POWERS: I mean, when you set up for a two-year cycle, does your balance plant tower under that kind of a cycle?

MR. HINDS: Would the?

DR. POWERS: The rest of the plant outside the steam supply system itself going to tolerate a two-year cycle?

MR. HINDS: Yes, we've designed it for that, and we believe it can.

DR. POWERS: Because that's usually the problem people run into.

MR. HINDS: Yes, certainly.

DR. POWERS: The fuel is fine. It's just that you've got to pick something else in the --

MR. HINDS: Certainly the plant needs to be well maintained. I'll agree with that.

DR. POWERS: Yeah.

MR. HINDS: Certainly. Here's a cut-away showing the reactor vessel and highlighting some differences. Many things within the vessel are similar to past designs, but then there are differences.

Differences, of course, we already talked about this. A taller vessel; the primary reason for the taller vessel is because of the addition of the chimney section.

DR. POWERS: Yeah. Explain that.

MR. HINDS: Okay. In the chimney section, that aids in the natural circulation, aids in the flow of steam insuring that we have a smooth, stable flow path, that there are no chances of oscillations between regions of the core. It gives it a straight shot out to the steam separators and steam dryers, and the separators and dryers are similar to past.

DR. POWERS: It's a consequence of having this bigger core?

MR. HINDS: The chimney is primarily there because it's a natural circulation, and I guess couple that with a large core as well. It helps promote the natural circulation, the steam portion of that flow path.

DR. DENNING: Are there flow stability problems without it? Is it clear or don't you really know? Is it just -- I mean, if you didn't have it in there, would there be a stability problem?

MR. HINDS: It would be much more difficult to prove that we had a stable lack of flow oscillations.

DR. SHACK: Now when I want to look for IASCC on the top of that, how do I do that?

MR. HINDS: Okay. Well, the refueling idea is to go down through the chimney, so if that's what you're -- refueling tools, as well as visual observations.

DR. SHACK: Crack this thing.

MR. HINDS: As well as visual observations and tooling would need to go down through the chimney section. And the chimney is a four by four arrangement. It's not one cell, but it's still --

DR. SHACK: Can I replace the top guide?

MR. HINDS: Can you replace the top guide?

DR. SHACK: Is it welded in, or is it

bolted in, is it sitting there?

MR. HINDS: I believe it's bolted in, and bolted in top guide, bolted in chimney sections.

DR. SHACK: So I can take this apart like an erector set.

MR. HINDS: Well, it's not a normal outage activity to take that apart, but it would be something that could be done. It would be a major evolution, though.

MR. BEARD: This is Alan Beard of GE. Specifically to that question, we are using the technology that we used on the ABWR. It is carved out of a single piece of stainless steel. We're not going to create plates and put them together in eggshell. It's milled from a solid piece of steel.

MR. HINDS: Right. As far as the actual grid within the top guide, yes.

DR. SHACK: But it's not welded to the support --

MR. BEARD: It is bolted in. It can be removed. It's not a planned evolution, but certainly one we're capable of doing in an extended outage.

DR. WALLIS: You said the steam dryer is like the usual ones?

MR. HINDS: Yes, it is. Of course, it's

--

DR. WALLIS: I thought that was something which was currently evolving.

MR. HINDS: Well, it is --

DR. WALLIS: It isn't the usual one anymore.

MR. HINDS: It is similar to the evolved steam dryer, I guess I should say; meaning, lessons learned from --

DR. WALLIS: It's not the big heavy one.

MR. HINDS: Correct. Correct, the big heavy one. The lessons learned from the Quad Cities and others, so we're -- certainly those lessons have -- the same people working on our dryer design are the ones working on the corrective actions from the older plant dryer issues. So yes, those lessons have been incorporated into this design.

Other differences - you notice the nozzles are up above core region. Here's core region here. The only penetration is down here. We've got control rod drives, and then we've got a bottom head drain line. Let's see. I guess that's it. Other areas are very similar to past designs.

DR. WALLIS: So what is the biggest pipe you've got below the steam pipe, I guess?

MR. HINDS: Well, the --

MR. SIEBER: Feedwater nozzle.

DR. WALLIS: What's the biggest pipe as you go up? You've got fairly little pipes, and the equalizing line is small.

MR. HINDS: I believe it's either the feed line or the steam line as far as the size of pipe. And if any of you know the --

DR. WALLIS: It's way up there.

MR. HINDS: Yes, the steam line is right out here.

DR. WALLIS: And the feedwater lines are next to it.

MR. HINDS: Feedwater line right there. And they're all --

DR. WALLIS: The pipes are all up there.

MR. HINDS: And they're all very high. And the core is down in here, so not to be -- with a visual, sometimes when people first look at it, they think this is the core, but the core is right here, so it's down there below these nozzles. Of course, there is a bottom head drain line, but other than that, the other lines are relatively high. There's a GDSC equalizing line. And again, we've got some more slides that will show some details on that.

At this point, I was going to hand-off to Alan Beard. He'll help get into --

DR. RANSOM: One question.

MR. HINDS: Yes.

DR. RANSOM: Was the equalizing line between the blow-down suppression cool and the vessel one item?

MR. HINDS: We have an equalizing line on it.

DR. RANSOM: SPWR had an equalizing --

MR. HINDS: It had an equalizing on here. It'll be shown in one of these slides that we're getting ready to come --

DR. RANSOM: It's not shown on the schematic, but --

MR. HINDS: Okay. It's on one of the upcoming schematics here, and yes, there is an equalizing line, which Alan is going to cover here in just a second.

MR. SIEBER: I take it your refueling pools are about 100 feet long? I mean, they would be -- that whole vessel from the bottom of the control rods to the top of the vessel is about 100 feet.

MR. HINDS: Oh, the distance down to reach a fuel bundle?

MR. SIEBER: Yes. And, of course, you have to add on -- you subtract from the top of the fuel down to the bottom of the vessel, but you have to add the depth of the water up above, so that makes for a long tool. Just controlling that I would think would be a challenge.

MR. HINDS: It's a long reach, yes. And so it does present a challenge in the design, in that we do have a long reach, and we need to have the proper equipment able to handle that. So yes, the refueling bridge is a challenge in this one.

MR. SIEBER: Now have you thought at all about how you would stabilize that tool because it would tend to want to move around.

MR. HINDS: Yes, we have some thoughts on that. We do have some further detail design to do of that.

MR. SIEBER: I'm sure I'll learn here later.

MR. HINDS: No, that's a very good point.

MR. SIEBER: All right. Thank you.

MR. HINDS: Very good point.

DR. WALLIS: Why is it such a big chamber between the tubing and the steam separator assembly? There seems to be a big chamber. You have this chimney with all these dividers in it.

MR. HINDS: Okay.

DR. WALLIS: And then you have what looks like a meter or two of space before you get into the steam generator. Presumably, everything will get more or less mixed up uniformly in there or something, or is it -- what's supposed to go on in there?

MR. HINDS: I don't think it's that -- unless it's mischaracterized on the drawing.

DR. WALLIS: This is quite a long thing, so I was wondering why it was so long.

MR. HINDS: Okay. Well, one thing that does need to be updated on this drawing is the top of the chimney area is actually flat across here. It appears in this drawing that it's --

DR. WALLIS: It appears to be a conical sort of thing.

MR. HINDS: Yes, it appears conical, but it's actually flat across there, so that's one thing that needs to be updated in this drawing.

MR. SIEBER: That depends on the view you took.

MR. HINDS: And that's just the area where the steam is heading to the separators, but as far as the reason for that -- you got any comments on that, Alan?

MR. SIEBER: There is a lot of separation going on in that empty space there, because coming up through the chimney you have a mixture of water and steam bubbles.

MR. HINDS: Sure.

MR. SIEBER: And once it escapes the chimney, the water has a tendency to flow back down and the steam continue on up. You need that much space to do that, I would think.

MR. BEARD: Yes. It's part of the element of you're starting to get the water --

MR. SIEBER: Separating out.

MR. BEARD: -- training out as you come up through the chimney, the part --

MR. SIEBER: Right.

MR. BEARD: And then when we break through there, it allows the steam to spread out, and we get equal flow up through the separators --

MR. SIEBER: That's right. Otherwise, you would have so much carry-over into the separators, that the separators would have to be huge in size, I would think.

MR. HINDS: It's a pretty large separator; but, yes. It's an area for the steam to mix, carry up into the separators, let the water flow back down into the down-come area.

DR. WALLIS: It depends a bit on what you call water level, doesn't it, on this whole thing.

MR. SIEBER: Well, that's sort of in the eye of the beholder.

DR. WALLIS: I guess we'll get into that some time down the road.

DR. RANSOM: The chimney is primarily to prevent -- well, it's presenting transition to --

DR. WALLIS: We don't know what the void fraction is in there, do we?

DR. RANSOM: So once you reach the disperse rate, it's no longer needed.

DR. WALLIS: is someone going to explain this? Do you have dispersed flow in the top of the chimney and a sort of sluggy flow in the column? Is there some sort of level in there, or is the level above the chimney, or what? Could you tell us that now, perhaps?

MR. HINDS: Well, there's a void fraction dependent upon the operating condition of the power level operating conditions. We've got a void fraction exiting the core region, and then basically lower quality steam coming up through the chimney heading to the separators.

DR. WALLIS: Where's the separation? Where's sort of the water level above which you get the high quality mixture? Is it in the chimney somewhere, where is it?

MR. HINDS: Yes. I mean, the core -- the top of active fuel does not -- it is covered. The top of active fuel is covered, including during accident conditions.

DR. WALLIS: The void fraction you get there is the same as the void fraction going up to the chimney pretty well?

MR. HINDS: I believe that is correct. I mean, there's no additional boiling once it occurs there, so the void fraction --

DR. WALLIS: There's no sort of level or anything in the chimney.

MR. HINDS: Right. It's a mass of steam. It's a mass of steam water mixture going up there with a given void fraction dependent upon power level. If you want to add anything to that.

MR. BEARD: No, I think David has stated it quite well, that the transition between solid water to a steam water mixture occurs down in the core. And once we exit out through the top guide, it's a pretty well consistent steam water mixture up through the partitions, and on up the --

DR. WALLIS: If the steam disappeared, the water would all settle down into the core.

MR. BEARD: That's correct, and I'll talk about that in the next couple of slides what happens.

DR. WALLIS: What we understood was that there was lots of water in there; and, therefore, it was safe. But if you're going to have most of the chimney filled with steam, then that takes away your lots of water.

MR. BEARD: And I will be addressing that in another slide or two.

DR. WALLIS: You'll address that.

MR. HINDS: Yes, it does collapse down such that the transient response is that the water settles down, the core is covered, and the transient -- the accident analysis shows core covered.

DR. WALLIS: You've got two sort of conflicting requirements. One is to get dry steam, you don't want a lot of water up there.

MR. HINDS: Yes.

DR. WALLIS: But to get safety in accident conditions, you want a lot of water up there.

MR. HINDS: Right. And the dry steam then occurs all the way up here --

DR. WALLIS: The chimney is fulfilling two functions. Right. Okay.

MR. BEARD: And the next slide, I think we'll be able to address that. I wanted to go back and touch on one other thing for David. On the bottom head drain lines for reactor water cleanup, we actually have four lines, and we have learned some lessons from our previous designs. We're no longer coming straight up through the bottom head. We have four nozzles out on the periphery of the bottom head come in, and then we have pipes that actually sweep down inside the vessel to draw suction out of there, so that we can remove the debris and any of the cold water that might be accumulating down there.

DR. WALLIS: This is because?

MR. BEARD: Because there's a lot of operating plants out there that have gotten so much debris down in that bottom head drain, they can no longer pull water through it, so we're trying to prevent that nozzle from getting plugged up.

Also, the severe accident stuff looks at it and says there is a possibility if you have chlorine, that's going to be the place that it's first going to attack, so we've eliminated that weakness.

Okay. Real quickly I wanted to touch on just a couple of design improvements. These are primarily made to address a lot of the maintenance concerns that our utilities have been explaining to us. One, we have made the decision that this plant will be capable of 100 percent steam bypass, and in doing that, that will allow us to transition to an island mode of operation should you lose your connection to the grid. One of the major points behind that decision was what happened two years ago here in the northeast with the massive blackout, so we felt it wasn't a whole lot of money to do that, and it made a lot of sense to go ahead and provide that capability.

As David said, we are using our fine motion control rod drives. Operational experience already with the ABWRs operating in Japan, also a lot of operational experience with similar designs in Europe. Shoot-out steel is just a maintenance nightmare for the utilities who have it. We've been able to eliminate it, same thing we did with the ABWR.

DR. WALLIS: What is it?

MR. BEARD: Shoot-out steel was our solution to handling the failure of a CRD housing weld to the vessel, such that if that were to occur, it restrained the shoot of a control blade from being ejected from the core. We now have an internal restraint system that provides that protection.

Integrated head vent pipe, this is just an issue that's trying to get some time off of our critical path. We basically incorporated a pipe inside the RPV head, and then the flanges that make that connection are built into the RPV head flange and the vessel flange itself.

Improved in-core instrumentation. We have taken -- historically, we had start-up range monitors, we had intermediate range monitors. We've combined those into a single operating device. The previous designs had very sensitive detectors in them, such that we had to withdraw them from the core once we got up into the power range neutron flux. With this design, we don't need to do that, so we've eliminated a lot of headache, again, with the maintenance of those devices. And then our local power range monitors or LPRMs, which make up part of the average power range monitor detection; previously, we had a system called the Traversing In-core Probe, the TIP system, involves three-eighths inch tubings that allowed us to insert a detector from outside containment up next to all the detectors in the core, and then when we withdraw it, we were able to compare the signals from both of those, and we could calibrate the individual detectors that way. We now accomplish that with what we call a gamma thermometer technology.

We've had some lead test assemblies out, had very good results coming back from that, and we're going to go ahead and incorporate that in as part of the base ESPWR design.

DR. WALLIS: While you're improving in-core instrumentation, do you have anything that measures where the water is, or what the void fraction is, or what the flow rates are in various parts of the core? Is that something which is just calculated?

MR. BEARD: It is calculated primarily; however, there are two thermal couples on the bottom of each of the LPRM strings just below the core plate so that you're measuring the water flow up through that, or measuring --

DR. WALLIS: Calculating whether it's superheated or not? If it's saturated, thermal couple doesn't tell you anything, would it?

MR. BEARD: Well, it's sub-saturated because it hasn't heated up yet.

DR. WALLIS: Well, it tells you that.

MR. BEARD: Yes.

DR. WALLIS: So it's way, way down.

MR. BEARD: It's immediately below the core plate. It's just before we come into the fuel range.

DR. WALLIS: Nothing above which tells you what's going on in terms of hydraulics.

MR. BEARD: Correct. No, the water level we're measuring is, we're measuring the area outside the annulus, using our typical differential pressure --

DR. WALLIS: And you're calculating everything else?

MR. BEARD: Excuse me?

DR. WALLIS: Then you calculate everything else.

MR. BEARD: Yes.

DR. KRESS: Are we going to hear more about the gamma thermometer concept?

MR. BEARD: I did not have anything prepared. I can try and answer your questions. I'm not a real expert in the area, but --

MR. SIEBER: Well, let me ask a specific question about those. Those gamma thermometers are not known to be as accurate as other types of active nuclear instrumentation. Is the accuracy of the gamma thermometer, that's really dependent on the geometry, is that good enough for the purpose that it will be used for?

MR. BEARD: All our calculations indicate yes, it's more than adequate to the serve the purposes we need to do, to calibrate our individual neutron detectors within the core.

MR. SIEBER: Yes, but I guess you agree that they aren't as accurate as some other types. Right?

MR. BEARD: Yes. There's certainly technologies out there that can be a lot more accurate, but for the purposes of making sure that we're tracking what's going on with the depletion of our --

MR. SIEBER: Yes. It's good enough. Right?

MR. BEARD: Yes.

MR. SIEBER: Okay. Gamma thermometers don't deplete.

MR. BEARD: No, but I mean the in-core instrumentation does deplete, so it has to be changed out anyway.

MR. SIEBER: Yes. Okay.

MR. BEARD: Natural circulation, there

were questions earlier about why do we need that big, tall chimney? Well, the bottom line is we need to get differential head, we need a driving head to do that, so we've got to have some sort of area where we can get that cold dense water offsetting the pressures drop going in here. So we have 25, 30 feet of very cold - I shouldn't say very cold - excuse me - sub-cooled water in this annulus space out here. This is the water that when we talk about we've got a large volume of water inside the vessel, it's the water out in this annulus space and up around separator pipes.

DR. WALLIS: So you can make the annulus bigger without changing the head just in order to accommodate more water.

MR. BEARD: Yes.

DR. WALLIS: This is an independent design you can make to hold more water.

MR. BEARD: Yes, they could be uncoupled, correct.

DR. WALLIS: Make the vessel bigger presumably, if you had the same core.

MR. BEARD: If we needed to do that, yes, that's true. Our calculations indicate we don't need it. We've got enough water out there to make sure, and those come up later on.

DR. WALLIS: And the assurance that you don't get any flow oscillations in this thing is calculations of some sort?

MR. BEARD: It's calculations, it's tests, data from the --

DR. WALLIS: Oscillation in the annulus going up and down. It's not going to happen, right?

MR. BEARD: Well, I mean, the annulus is going to be -- level is going to be controlled by our feedwater level control system. We're monitoring what that level is, and feedwater is going to -- the amount of feedwater coming in --

DR. WALLIS: It starts to oscillate, then you're going to have feedwater flow oscillating and everything. All that's just a calculation, is it? You're going to get into this in detail, I suppose, down the road.

DR. KRESS: We should have a thermal hydraulic --

DR. WALLIS: Either you have a natural circulation thing to worry about some sort of oscillation starting.

MR. BEARD: Well, the oscillation is going to be a result of what's going down in the core. It's not a result of what's going --

DR. WALLIS: Well, it will also make the annulus go --

MR. BEARD: Well, the feedback will obviously be up in the sub-cooled water, but it's going to be because of what's going on in the --

MR. SIEBER: You built some test facilities to test this chimney, right?

MR. BEARD: No. Our test facilities were primarily for testing the passive safety-related system.

MR. SIEBER: Taken from somebody else's work.

MR. BEARD: Right. The Canadians did some work, and then there's obviously the Dodeward facility that is also natural circulated that we have a lot of information from.

DR. KRESS: I presume you've got a pretty good neutronic analysis of the flat core with that many fuel elements and pretty high volume fraction to a great deal of it?

MR. BEARD: Again, that's not my area of expertise, but the guys who are experts in that area assure that we are a long way away from --

DR. KRESS: Well, make a note that at some point during our review we'd like to see that.

MR. BEARD: Obviously.

MS. CUBBAGE: Yes. We're planning to come -- GE will be back in either January or February for a full day with the thermal hydraulic subcommittee, specifically on the issue of stability. The Staff's been reviewing their --

DR. KRESS: No, there's normal BWRs to get into what you're about. But here, I'm worried about one part of the core not communicating with the other part, having local areas that are unstable with respect to each other.

MR. SIEBER: Well, you're talking about the potential for xenon transients and things like that.

DR. KRESS: Yes. Exactly.

MR. SIEBER: That give you oscillating tilts.

DR. KRESS: Yes.

MR. SIEBER: And that is a pretty big core. The power -- it probably is not real high.

DR. KRESS: Yes, that's exactly what I'm wanting to hear about, so put that on your list.

MS. CUBBAGE: We've already asked --

DR. WALLIS: I'm thinking instead of having one day just on this one issue, the thermal hydraulics, we probably need several days.

DR. KRESS: We may need several days.

MR. SIEBER: Days, weeks.

DR. KRESS: Years.

MR. BEARD: Just one other thing I wanted to comment on this slide. The other –- we have a lot of water out here to maintain or make sure that we can keep the core covered during all transients and design-basis accidents. But the advantage of this big volume being hefty is our pressurization transients really are very benign relative to our operating BWRs. In this case, design-basis accidents and anticipated operational occurrences, with the exception of ATWS, our safety relief valves are never calculated to come open.

DR. KRESS: You've got a big capacity.

MR. BEARD: We've got a very huge capacity. That's with the isolation condensers working. If the isolation condensers do not work, it's still five minutes before the pressure of this reactor vessel would get up to the point that we'll lift the safety relief valve, so there's a real big advantage to this huge volume of steam that we have in this area right here.

I'll talk real briefly about anticipated operational occurrences. We recognize that those transients are initiated to accidents, and so we're taking efforts to try and minimize those from being the initiating transients. Primarily, what we have done is we have adopted a triplicated control system for both feedwater level control, as well as steam bypass and pressure control. Those are the big hitters on BWRs as far as transient initiators, and so with the adoption of that improved technology, or control instrumentation technology, we feel that those initiating events will be significantly decreased. Rick will talk a little bit more about that when he gets into the PRA.

Large steam volume I already talked about. There's no pressure over-shoot. It's a very benign pressurization transient. Our critical power ratio is lower than you would see with a typical forced circulation BWR. Our limiting event for critical power ratio is a loss of feedwater heating, but it's a very slow evolving event, very easy for the operator to recognize and take mitigative action to terminate that event.

Loss of coolant accidents - we've got a large margin of fuel uncovery. In fact, we never uncover the core for our design-basis accidents, or any of our anticipated operational occurrences. And we're only crediting passive systems when we make that statement. And we are designed for at least 72 hours of capability without reliance on any sort of AC power.

DR. WALLIS: So what is it that ever gives you any core damage?

MR. BEARD: If I keep my core fully covered with water, I can't melt the core.

DR. WALLIS: Okay. So what do you have to do to get core damage, because you do have some core damage frequency. It's not zero.

MR. BEARD: Rick will get into that, but the core damage frequency would be that we can't get water back in the vessel for whatever reason.

MR. SIEBER: Or you have a hole in the bottom.

DR. KRESS: It must be long-term. You can actually dry it out.

MR. BEARD: Well, no. I think I'll be able to address that in the slides when I get to the isolation events from the PCC. And then transients without scram - again, the large contributor to ATWS for BWRs was this cool discharge volume that we had with our older locking piston CRD mechanisms. With the fine motion control rod drive, we still have a hydraulic scram, but we only have insert lines so there is no scram discharge volume, so that part of the initiating frequency has been entirely removed within this design.

We do have diverse means for inserting the control rod into the core should the hydraulic function fail. That's not what we credit for satisfaction of the ATWS rule. We do have a standby liquid control system for that purpose, but our first attack on an ATWS is if we fail to hydraulically insert the rods, there is circuitry that automatically commands the FMCRDs to go into the run-in mode and to try to insert the blades electrically. If that fails, then we would use the liquid poison system, the standby liquid control system to inject sodium pentaborate and bring the reactor sub-critical.

DR. DENNING: You control power in this case with control blades.

MR. BEARD: That is correct.

DR. DENNING: Now does ABWR do that? You talked about --

MR. BEARD: No, the ABWR we have the ten reactor internal pumps, so we were varying the core flow by adjusting the speed.

DR. DENNING: So you've got a bite in the core all the time? I mean, does it lead to quite a bit of difference in the burn-up of the fuel and your control of --

MR. BEARD: All the analysis our core group has done says we will be able to get the same type of core performance from this reactor as we are with the forced recirculation. There is an increased duty cycle on the FMCRDs, but we have done plenty of testing to say that's not going to be a problem for the mechanisms themselves.

With the accumulator standby electric system versus the old motor-driven pumps that we have, we are able to get the sodium pentaborate into the vessel a lot faster. It's about five times faster than with the pump systems, and it's about five times greater than what is deterministically required by the ATWS rule.

Bottom line is we can go ahead and get the reactor sub-critical without having to depressurize the vessel. And once we do get sub-critical, the isolation condensers will terminate steam flow to the suppression pool. We'll come back, the pressure in the reactor pressure vessel will come back below the safety valve set point, safety valves will reseat and we're back into a closed loop system.

DR. WALLIS: And the operators don't have to do things.

MR. BEARD: For the first 72 hours this plant is designed such that there should be no --

DR. WALLIS: In an ATWS?

MR. BEARD: It an ATWS, that's all automated, as well.

DR. WALLIS: Okay.

MR. BEARD: Okay. This is a very high level cartoon of the passive safety systems. It does not have the standby liquid control system on it. The IC, we have four isolation condensers, anomaly four by 33 percent, so we can have a single failure in one of those isolation condensers and still have 100 percent of the capacity that we need for our design-basis accidents and our transients.

PCCs, there are six of them. Again, we could fail one of those. What the failure mechanism is, we haven't figured out, because it is entirely passive. There is nothing in that system that needs to reposition itself to put the PCCs into operation. And then we have the gravity-driven cooling system. We've got three bodies of water in the upper dry well airspace or upper dry well. They are elevated above the core, as you can see by this figure, and they are the means that we have for flooding the core and maintaining core cooling.

I'm going to talk more specifically about each of those systems in the following slides. The equalizing line I heard asked about before. Mr. Graham, I wanted to go back to the one question you had earlier. PCC heat exchanges are treated as part of the primary containment boundary. The isolation condensers are not. We do have containment isolation valves to isolate those heat exchangers, if you were to develop a leak out in one of those --

DR. WALLIS: What's new in this is really those heat exchanges and condensers, and they've all been tested full scale.

MR. BEARD: We have done full scale testing of a module, one-half of one of these. We didn't have both pieces and --

DR. WALLIS: It was full scale.

MR. BEARD: It was a full scale test.

DR. WALLIS: And the pools are routine, and the vents and all that, but some interaction between the components is something new here.

MR. BEARD: There was also scale testing done of the entire interactive --

DR. WALLIS: The entire system.

MR. BEARD: Yes.

DR. RANSOM: You've got eliminate of the vacuum breakers?

MR. BEARD: Well, we still have three larger vacuum breakers not shown on this figure, but they are located in the diaphragm floor itself.

DR. WALLIS: These were the new mysterious design which never fails. Is that the one?

MR. BEARD: We hope they -- well, I shouldn't say hope. We don't believe they will fail. We've looked at them in attempts of improved design.

DR. WALLIS: They are a different design from before.

MR. BEARD: They are. They are more of a lift-type than the swing-type.

DR. WALLIS: They're much more reliable now?

MR. BEARD: Yes.

DR. WALLIS: And that's been proven?

MR. BEARD: We have done a testing program on that to demonstrate the reliability, that they also have a means to establish closure should the passive nature of that valve fail.

DR. WALLIS: I guess that's another thing, the thermal hydraulic subcommittee should look into all these new features that we haven't seen before. Tests of these, we'd like to see the evidence as to the vacuum breakers, I think, things like that. We'll work that out.

MR. BEARD: Okay. Passive safety systems, two of the three big ones are the isolation condenser, the PCC. Isolation condenser has replaced the old RCIC system in our previous designs. It allows us to basically remove heat in a closed loop system. We have no steam venting off through the safety relief valves. Basically, it works, we take steam out of the vessel. It enters into the upper steam drum, is distributed out through the tubes. As the steam condenses in those tubes, the condensate accumulates in the lower drum, and the is returned back to the reactor pressure vessel in the outer annulus part of the vessel.

PCCs, once we have a LOCA or if we need to depressurize the vessel and induce a LOCA, the steam in the dry well, if it's a LOCA, the initial pressurization of the dry well is handled by the stem or the normal pressure suppression function. We depress the water column in the connecting vent, uncover the horizontal vents, the steam exhausts out into the suppression pool. It's condensed limiting the pressurized as a result of the large break LOCA. That goes on for 30-40 seconds, at which time the PCCs have established their driving flow through them. They will start managing the pressure. The pressure in the dry well will start to decrease, and the vents here will recover themselves.

At that point, we do not expect that we ever would have a need for these to –- or the pressure in the dry well will never go up again to the point that we actually have to uncover those vents again, so there's no more heat being put in the suppression pool via that mechanism. There is another way that we do get some heat in the suppression pool during the 72 hours, and I'll talk to that in an upcoming slide.

In 72 hours the passive capability is basically accomplished. We have this heat exchangers sitting in these bodies of water. We've got a huge amount of water sitting in the elevated location in our reactor building. You see actually three different pools. Inter-connected pool here with all these heat exchangers, another large inter-connected pool for all these heat exchangers, and then we have this body of water in the PRV cavity in the equipment pool that is available to extend us out to a 72-hour capability.

Each one of the PHDHs is in it's own compartment. We compartmentalize that to allow us to do maintenance on individual heat exchange without having to drain the entire pool. There is a pipe that connects the two pools here. In the event that you wanted to do maintenance, you would close that valve and then pump the compartment out to do any surveillances or whatever might be necessary on those particular heat exchangers.

DR. POWERS: OSHA must just absolutely love that one.

MR. BEARD: It's a confined space, yes.

DR. WALLIS: Why is that pool divided by that wall that has those two white things in it?

MR. BEARD: As part of the structural arrangement of the building.

MR. SIEBER: The middle one is the reactor head.

MR. BEARD: Yes. Right.

DR. POWERS: And an important accouterment.

DR. WALLIS: I was looking for a big green pool.

MR. BEARD: That's just one of the column lines, and what happens is up on the refuel floor is the building wall actually steps in at the refuel floor elevation, so that's -- at the floor right above this, the building wall runs along that line and that line, so it's just a structural element.

Again, I'm going to get into more detail, but the gravity-driven cooling system, once the vessel is depressurized, we now can take advantage of the differential head between that elevated pool and the elevation that we're injecting the water into the vessel. We have three pools inside the containment air space. The volume of water in those three pools is such that when we open up the valves, not only do we flood the RPV and keep the water level in the RPV above the top of active fuel, but if we have a line break, there's sufficient water in those pools, such that the water in the RPV is kept above TAF. We also fill the entire lower dry well region up to a point that it also is above TAF.

DR. WALLIS: Those pools here are round, but the pool on the top is rectangular. Is that it?

MR. BEARD: They're kind of -- well, they're round on the outside, and then they're linear on the inside surfaces.

DR. WALLIS: But then the pool you showed us that had the green pool, that's on top of all of this, is it?

MR. BEARD: Yes.

DR. WALLIS: Okay. It's rectangular and it fits on top of all of this.

MR. BEARD: Correct. The ICMPCC pools are on the --

DR. WALLIS: And they're rectangular things.

MR. BEARD: Correct. Okay. LOCA water response, just wanted to compare to our previous designs in our BWRs four through sixes, which really represents the vast majority of the fleet that we have domestically. In the design-basis accidents, the best we could say was we could maintain two-thirds core height coverage, because of the assumption that --

DR. WALLIS: This is two-phased level, or is this --

MR. BEARD: Single phase.

DR. WALLIS: -- collapsed level?

MR. BEARD: Collapsed level.

DR. WALLIS: It's a collapsed level, so the two-phase level is way above that.

MR. BEARD: Well, this is after we SCRAM in a reactor, so there's very little two-phase flow actually going on. You, obviously, will be boiling, but that's not the vigorous boiling you'd have at power operation. Two-third core height with our existing plants because of the jet pump elevation and the assumption that it was a recirc line break that got you into the accident.

With the ABWR and the active systems, and also the elimination of the external recirc pumps, or the recirc piping loops, we were able to demonstrate with active systems that the lowest we expected water level ever to get to in design-basis accident conditions was about a half a meter above the top of active fuel. Now with the ESBWR, using just entirely passive systems, the lowest water level we get is even above that. This low water level in the ABWR was occurring in the 40-second time frame, low water on the ESBWR is occurring out in the 500-600 second time frame.

DR. WALLIS: That's the very worst case.

MR. BEARD: That is the minimum water level that we --

DR. WALLIS: With conservative assumptions and things, too.

MR. BEARD: With design-basis assumptions, yes.

DR. WALLIS: So it's conservative assumption. This isn't some sort of a best estimate. This is --

MR. BEARD: No, this is licensing basis calculations.

DR. WALLIS: With conservativism in it.

MR. SIEBER: This is basically just a pretty simple problem. It's just volume.

DR. WALLIS: Yes, I just wanted to get, does he make conservative assumptions, or is this the best estimate, in which case you'd --

MR. BEARD: Well, it's calculated by TRACG.

DR. WALLIS: Oh, so this is a best estimate. So there's uncertainties in that line? Are you showing me the mean depiction or the worst case prediction? You see what I mean?

MR. BEARD: Using TRACG, that is a worst case calculated water level.

DR. WALLIS: Worst case. It's not the --

MR. BEARD: It's not the mean.

DR. WALLIS: -- best estimate. It's not the mean. It's the worst.

MR. BEARD: It's not the mean.

DR. WALLIS: Uncertainties on --

MR. BEARD: For the limiting transient, limiting design-basis LOCA, that is as low as our water level gets calculated by TRACG.

DR. WALLIS: Worst assumptions about everything.

MR. SIEBER: With a reactor vessel that tall, you would expect a result like that. I mean, there's a tremendous amount of water in that vessel.

MR. BEARD: And part of that is yes, you can do simple hand calcs and see what the volumes of water do once you remove them.

MR. SIEBER: Run a meter, may be even better.

DR. WALLIS: So this is a bounding calculation?

MR. BEARD: I don't want to use the term "bounding". We're using TRACG, which is an approved code, and that is the water level we have for --

DR. WALLIS: TRACG has uncertainties in it. I just want to know how you're taking account of them.

MR. BEARD: Ralph, if you would like to jump in and bail me out, I would greatly appreciate it.

DR. WALLIS: Which is it, is it neither?

MR. LANDRY: It's a strange feeling for the Staff that they have to bail out the Applicant.

MR. BEARD: I appreciate it.

DR. POWERS: What do you mean? It happens with regularity.

MR. LANDRY: This is Ralph Landry from the Staff.

DR. POWERS: Sometimes the other way around.

MR. LANDRY: The analysis that has been done is similar to the analysis that was done when we reviewed TRACG for LOCA for ESBWR and presented that material to the subcommittee and to the full committee. This is more of a bounding-type calculation than a best estimate or realistic calculation. It's using a realistic code, TRACG, but they have not done the full uncertainty analysis as we have seen in other places with a code for a LOCA calculation.

DR. WALLIS: So this is a sigma thing, is that what it is?

MR. LANDRY: This is using the two sigma bounds on the parameters to stack up the worst limit on each parameter important to the LOCA for this design, so in reality, it's using a realistic code with the worst case parameters, rather than doing an uncertainty analysis and a statistical analysis on all the parameters as inputs. So you've stacked up the worst parameters for this analysis, and with the --

DR. WALLIS: At the two sigma level.

MR. LANDRY: I'm sorry, Bill.

DR. WALLIS: It's at the two sigma level.

MR. LANDRY: Correct.

DR. WALLIS: You reminded me of what I heard before, but I was asking now to see if the new generation of GE people knows what they did. At least you remember, Ralph.

DR. POWERS: So what you're saying is you knew the answer, and you were just testing everybody.

DR. WALLIS: I was testing him, and he didn't seem to know.

MR. LANDRY: Graham has never given up trying to test me.

MR. BEARD: We'll have to bring our thermal hydraulics guys the next time.

DR. RANSOM: Was this level at 72 hours? Is that the level --

DR. WALLIS: It's 500 seconds.

DR. RANSOM: It's 72 hours?

DR. WALLIS: No, 500 seconds, I think he

said.

MR. BEARD: That's the worst water level before GDCS start to inject water into the vessel, or the flow water. I shouldn't say inject, in this case it's a vigorous flow.

Just to give you an orientation to how this looks, one of the differences from the SBWR versus the ESBWR, SBWR we were storing our spent fuel up in the reactor building. We have made the decision to go to separate spent fuel building, grade level on this plant is right here. So the spent fuel pool is entirely below grade and --

DR. WALLIS: When you take the fuel out, you have to have some kind of arm which gets shorter as it pulls the fuel out so you have room for it?

MR. BEARD: Well, we have a collapsible mast auto refuel --

DR. WALLIS: The building doesn't look tall enough to get everything in there.

MR. BEARD: There is a refueling platform that goes here that has a mast that extends out in sections, latch onto the bundle and then you retract it.

DR. WALLIS: That's in sections.

MR. BEARD: Yes. It's a telescoping mast.

DR. WALLIS: You have to do that, otherwise you'd never be able to do it.

MR. BEARD: Correct.

MR. SIEBER: You could add 50 feet to the building.

MR. BEARD: I don't think we want to do that. And then to transport fuel from the upper pools here down to the lower pools, we use what we call our incline fuel transfer system. We have that on our Mark III containment. The big improvement here is on Mark III, this actually penetrated the primary containment, so we had a lot of surveillances that went with that. It's now located entirely outside the primary containment, no leakage concerns regarding the usage of that.

Just wanted to give you an idea how much water we are talking about here. Like I said, when we dump these GDCS pools, these three pools, water level in the reactor will basically be up to that line approximately, as well as the water throughout this area. So even the bottom head drain line break, we're continuously dumping water out the bottom, you still would have this water located here that would keep water up above top of active fuel at all times.

Okay. Talk about the isolation condensers real quick. They are designed to remove the passive decay heat from the reactor pressure vessel when we're at pressure. As pressure goes down –- well, as long as the system is in tact, the isolation condensers will perform their function. They will at some point, when we get down to lower pressures, lose their heat removal capability and you get into a state where you kind of maintain a steady pressure, but it's a safe shutdown state no matter what.

We have applied the single failure criteria. We only need three out of the four to operate. When you get to the schematic, you'll see even beyond that we have some additional features that say even if you have a single active failure, you don't disable an isolation condenser by that single active failure. It operates in all design-basis conditions, except for medium and large break LOCAs where we do depressurize the vessel. There is some heat removal capability. We don't attempt to quantify it or take credit for it.

Like I said, with the ICs, we have no lift to safety relief valves for any of our design-basis accidents or transients, and that includes isolation from the main condenser. We think one of the real attractive things about this design is when the ICS take the heat from the nuclear steam supply system, they transport it directly to the ultimate heat sink. There is no intermediate step. When that water in that pool starts to boil, the steam is exhausted out directly to the atmosphere, and there's no additional cooling step that we have to go through.

DR. WALLIS: How much venting do you have to do with a large break LOCA?

MR. BEARD: Venting.

DR. WALLIS: This doesn't have enough capacity to condense all that steam.

MR. BEARD: The isolation condensers in a large break LOCA are not credited with the condensation of the steam.

DR. WALLIS: So you just vent it to the world?

MR. BEARD: Well, it vents into the containment, could take the suppression pool, takes the initial --

DR. WALLIS: It stays in the containment, though. It doesn't come out into the world.

MR. BEARD: Correct.

DR. WALLIS: I wanted to make that clear. It's not being condensed in the isolation condensers, but it's going into the pool and being condensed?

MR. BEARD: In a large break LOCA? The initial part goes into the suppression pool. After the initial blow-down, the PCCs are condensed in all the steam.

DR. WALLIS: Just didn't want to give them the impression that you were venting to somewhere other than the containment, which is not true.

MR. BEARD: If I conveyed that impression, I did not intend to do so. Okay. Those of you who have been around the business, and this entire body obviously has. When you look at the decay heat curve with the three ICs in operation, look at the whole pressure where it is, and very quickly, 20-30 minutes in there you will start to see the very significant cool down of the reactor pressure vessel. In fact, it is so fast that if we try to limit or to maintain 100 degree Fahrenheit, 100 degree Fahrenheit per hour cool down on the reactor pressure vessel will actually have to start throttling back the ICs to make sure that we stay within that cool down limit.

Having said that, we have designs such that an occasional transient where you have excessive cool down is not going to –- it's one of the analyzed conditions for the reactor pressure vessel, but we fully expect that the operators would step in and try to start moderating the cool down.

DR. SHACK: Now your fluences on the vessel are going to be similar to those from the ABWR?

MR. BEARD: Actually, the fluences are a little bit higher. We have done calculations, and they are within the acceptance criteria that we have established.

DR. SHACK: But they are higher.

MR. BEARD: They are higher. The water gap is smaller. We've got a lot more fuel in there, but we are going with forged ring shells in that area, that high fluence area, to address those concerns.

Okay. I just wanted to put up this schematic of one of the single ICs. This is showing the IC when it is in the standby condition. We do keep the ICs in a hot standby condition during normal operation, and what I mean by that is, the steam line is open. We have steam up to basically the high point of the system, right where I have my pointer right now. And then the rest of the system is filled with condensate grade water.

DR. WALLIS: So it'll stop. It's got enough water in it to get going when it needs to get going.

MR. BEARD: Right. So I have the entire

static CAD coming down from there full of water at all times. I do have steam up here. There will be some condensation because I'm losing heat out through the shell of the pipe. The pipes are pitched so that we do have drain back. Also, to address the concern about accumulation of non-condensible gases, specifically hydrogen, we do have a vent pipe that is attached to the upper points of this header pipe. It's a nominal three-quarter one-inch pipe, comes down and is continuously vented to the main steam line. The way we're able to do that is on the nozzles we have a flow venturi that establishes basically a 40-pound pressure drop across that venturi. The steam line here is on a stub tube that does not have a venturi device, and even if it did, there is no flow here normally, so there's a 40-pound difference between the steam inlet here and the steam pressure here, so we're able to continuously sweep that pipe for the non-condensible gases that might ––

DR. WALLIS: You don't need much flow at all.

MR. BEARD: You don't. No, like I said, it's about a one-inch line, and there's even an orifice built into it.

MR. SIEBER: Is the flow large enough to

control the chemistry in those lines?

MR. BEARD: There is no flow in this portion of piping.

MR. SIEBER: Okay.

MR. BEARD: But it's also all stainless anecano tubing.

MR. SIEBER: Anecano. Okay.

MR. BEARD: Were there any questions on that? I should go back, I'm sorry. I mean, it's all -- in this case, you're sitting in a body of water that's nominal 100 degrees Fahrenheit, and that's what the water -- the temperature of that water will be until we initiate it. When it comes time for the IC to go into operation, the isolation valves in hot standby are kept open. The only thing preventing the system from operating is these two parallel, what we call condensate return valves. We command both of those to go open and the water starts to drain in here, start uncovering tubes, and we start to get a rapid condensation of the steam that's entering into that tube area. In fact, it is so rapid that we have to slow down the opening of these valves to make sure that the amount of cold surface that we expose is done in a regulated manner to make sure that we don't have steam or water hammer issues.

DR. WALLIS: So how do those valves open, by what mechanism?

MR. BEARD: Well, that's a good question. NO stands for nitrogen operated. It's a pneumatic piston assembly. Those four valves, because there's one of these for each of the flow isolation condensers, are actually set up such that should they lose either pneumatic pressure or the electrical signal to the cellanoid, they will fail into operation. The valve will stroke open. The other valve is just a safety-related electrical MOV that you would send the signal to and command the valve to go to the open position.

NMR stands for nitrogen motor operated. We have some diversity here, as well, to make sure that if we need to, we can isolate that.

MR. SIEBER: How do you control the valve speed, with a snubber?

MR. BEARD: Yes, some sort of hydraulic --

MR. SIEBER: On the stem.

MR. BEARD: Yes.

MR. SIEBER: Okay.

MR. BEARD: Well, it could be that, or it could be metering off the pressure of the air. I don't want to commit to whether it's pneumatic or hydraulic.

MR. SIEBER: So you don't know.

MR. BEARD: I fully suspect that it's going to be a hydraulic ash pot, but there is a possibility it could be a meter into --

MR. SIEBER: Okay. Thanks.

MR. BEARD: Passive containment cooling - as I said before, we have six passive PCC heat exchangers. They operate in medium and large break LOCAs. We say they provide backup to the ICs, if needed. The way they provide that is we depressurize the vessel. In fact, it becomes a LOCA when we open the depressurization valves, so we have steam in the dry well and the PCCs, we're moving the decay heat from the containment. They are entirely passive. There is no valves on the entire system, nothing needs to be repositioned for them to go into operation. We only need steam in the dry well in order for them to start operating removing heat.

Forty-hours worth of demineralized water - that was those teal-colored bodies of water I showed you, to get beyond. To get out to 72 hours, I only need to open one of the four valves up on the floor to allow the water, that darker blue water to circulate out into the heat exchanger compartments.

Graphically, we have a steam environment now in the dry well. As I said, the initial 30-40 seconds of blow down is handled by the suppression pool. All of the PCCs are doing some amount, but after the initial blow down starts to tail off, PCCs of steam enters up through the central pipe. It is distributed out to the headers. They fill the pipes, condense the water. Water is collected and then it is returned back to the GDCS pools. There is a loop seal on that pipe to make sure that we don't ever have an attempt to introduce steam back up the opposite way.

To address the issue of non-condensible gases building up in the PCC, and degrading the heat transfer, we have a continuously open vent line. And what happens here is, you can see that the submergence of that sparger on the end of the vent line is less than the upper level events, so as my decay heat capacity removal starts to decay in here because of the build-up of non-condensibles, pressure in the dry well will start to increase. I will start depressurizing the water column, and at the point that the pressure is equal to the submergence here, I will uncover that, and I will blow a combination of steam and non-condensible gases through that sparger. The steam, obviously, will be condensed by the water, non-condensible gases will be accumulated in the wet well air space.

DR. RANSOM: Is that one valve you had open shown there between the IC and the --

MR. BEARD: No.

DR. RANSOM: That's not it.

MR. BEARD: I can go back. There are two connections here, two connections here, each one of those has a valve on it. At 40-hours, I only need half -- no more than half of these, so any one of those four valves opening is going to ensure that I can get out to 72 hours.

DR. RANSOM: Well, what is that, dark blue is sitting up on the roof, too?

MR. BEARD: That dark blue is the water that's in the RPV cavity in the equipment pool. The reason for that is, this is demineralized grade water, this is condensate grade water. Same chemical constituencies, but there is no levels of radioactive contamination in the condensate, so during normal operation we don't want the bodies of water mixing.

DR. WALLIS: Now is this non-condensible vent line - why doesn't that take condensate, as well?

MR. BEARD: It will. There will be steam that comes out.

DR. WALLIS: And condensate, and water, too.

MR. BEARD: Well, actually it would be more -- I don't know that that's graphically correct. It probably taps off on the vertical leg.

DR. WALLIS: I think something of it's --

DR. RANSOM: They have a separator in --

DR. WALLIS: Something that's not exact about the drawing, perhaps. It looks as if the condenser --

MR. BEARD: Probably, we ought to have these pipes switched around.

DR. WALLIS: Drain down into the sparger instead of going to the condensate drain lines.

MR. BEARD: Yes, I think we need to have these pipes switched around.

DR. WALLIS: Something doesn't look right.

MR. WACHOWIAK: Those dotted lines indicate that the vent pipes go to the top and --

DR. WALLIS: They go inside. Okay. Thank you.

MR. BEARD: Thank you, Rick. Rick Wachowiak says those dotted lines indicate that the vent pipes extend all the way up into that lower drum.

DR. WALLIS: That's clearer now. Thank you.

MR. BEARD: Emergency core cooling - talked about how we have three GDCS pools that contain approximately 1,700 cubic meters of water, 264 gallons of water to a cubic meter if you want to do the math. There are four trains of GDCS. Much like most of our centralated systems, we do have four trains. In order for the GDCS to work, we have to have a depressurized reactor pressure vessel. If we have a large break LOCA, that's going to do it for us. If we don't have a large break LOCA, if we have a small break LOCA or the isolation condensers fail to operate, we need to depressurize the RPV. How do we do that? It's actually two stages.

The initial depressurization of the vessel is done just like we do on our existing plants. We open up designated safety relief valves to provide the initial depressurization, the steam is exhausted from those safety relief valves out through tail pipes into quenchers that are located at the bottom of the suppression pool condensing the steam that goes out that. Through that we'll get down to about nominally a 20-pound pressure in the reactor pressure vessel.

At that point, we have eight Squib actuated depressurization valves that will be fired to go ahead vent the steam directly out into the dry well air space, now equalizing the pressure in the RPV with that in the dry well air space, and establishing conditions where the GDCS can flow into the RPV.

DR. POWERS: And, again, how many of those have to work?

MR. BEARD: From deterministic basis or licensing basis, we say seven of the eight. They are single failure proof. I think PRA has looked at it, and is it five, three, five, we need five of the eight.

MR. SIEBER: Are they of a size that you've already manufactured with the Squib valve?

MR. BEARD: They are a size that we did do a full test program on.

MR. SIEBER: Okay.

MR. BEARD: And they are smaller than the ones used on other vendors' designs.

MR. SIEBER: Right.

MR. WACHOWIAK: This is Rick Wachowiak of General Electric. In the deterministic analysis, since they only need to look at a single failure, they have evaluated it with seven of them opening. I don't think they even looked at more than one failing. In the probabalistic calculations, the input for the probababilistic calculations, we can show that if three of those valves open, we'll get sufficient GDCS into the reactor to cool the core, so we set our success criteria at four, one greater than that. So if we have five failures, we'll consider that a failure of the system.

MR. BEARD: And I should mention that on those GDCS valves, they're Squib actuated. Each one of those valves has two Squib charges, one of which needs to fire to cause the valve to guillotine open. I've already said this before, core does remain covered for the entire range of design-basis accidents. As long as I keep water over the top of the fuel, I'm not going to have any core heat-up, so we obviously comply with the requirements of 50.46. The codes that we use to demonstrate that have been approved by the NRC, TRACG, as Ralph was able to bail me out. And the stored water contained inside the containment is sufficient to always keep this flooded up above top of active fuel.

GDCS has what we character as two modes, actually three modes of operation. I'm only going to talk about two. The third mode is to deal with the severe accident scenario. The first mode is what we call our short-term cooling mode; that is, as we see, this is Division A, is typical of one of the four divisions. There is a pipe from, in this case, the two smaller GDCS pools, each have one connection. The larger of the three GDCS pools has two of the trains connected to it. Pipe comes out of that pool, comes down, and then actually separates into two routes attached to two different nozzles on the RPV. Each one of those pipes has a check valve that has a biased open check valve that's accomplished by magnetic torque motor that keeps the valve slightly off its back-seat position. It also allows us to exercise that valve to make sure that it hasn't bound up. But the actual flow into it is when we initiate or fire the Squib charge, opens up the flow path, and then the check valve is there just in case for whatever reason we inadvertently fired that valve during power operation. You won't get flow back out of the vessel, or if there was some scenario where you had repressurization of the vessel following the firing the Squib, we again prevent back-flow through that. So there are eight total of these injection paths. Again, deterministically, we say seven are required PRA. I forget how many he says are needed for success, but it's significantly less than those eight.

Long term we have, again, four trains. It's called the sequelizing line. The reason for this is the PCCs over 72 hours or longer are going to have a net transfer of condensate from the upper dry well, the dry well region over the suppression pool. That's happening because we have that operation of the vent. There is going to be transfer of condensate again from the dry well air space over to the wet well. So at some point, the suppression pool here is going to start to rise. The water level in the dry well is going to start decreasing because I'm moving water over there, constant volumes, and so at the point when the water level in the suppression pool exceeds the water level in the dry well, we can now open that equalizing line, allow gravity to flow that water from the suppression pool back into the dry well, maintaining constant level within the containment spaces.

DR. WALLIS: Now does this automatically happen, or do you have to fire something?

MR. BEARD: Again, it is a Squib valve that has to be fired.

DR. WALLIS: So there has to be some sensor that tells you when these levels are just right before you fire it?

MR. BEARD: There is sensor, and I think there's also a timer on it that says at some point even if we haven't detected it, we're going to go ahead and do it. Part of that is, I don't have prepared slides, much like the AP-1000, our control and monitor function we only support with 24-hour batteries. At 24 hours, we say we've gotten the plant into a stable safe shutdown condition. We're going to be able to monitor it for the next 48 hours, so we would have to open that valve prior to losing the electrical capability to open it. But again, I have a check valve there. I will not have back-flow out into the suppression pool, and my water levels will stay equal. Even if I did have back-flow, they're going to equalize out at some point.

DR. WALLIS: Say that again. You've got a check valve in series with this?

MR. BEARD: Right there.

DR. WALLIS: Only allows flow into the reactor.

MR. BEARD: Only flow into the reactor.

DR. RANSOM: At this point, the PCC pools have dried out?

MR. BEARD: Which point, when this is

occurring?

DR. RANSOM: At the point that you would open this bypass or equalizing line.

MR. BEARD: Opening that valve is entirely independent of what's going on in the PCC/ICC pools.

DR. RANSOM: Why would you open it unless you have dried out the cooling capability --

MR. BEARD: Like I said, the PCCs over long-term operation are going to transfer condensate from the dry well to the wet well, so the water level in the dry well is going to start to depress, water level in the suppression pool is going to come up. I want to be able to equalize them out again.

DR. WALLIS: Actually, if the check valve works, you don't really need that valve.

MR. BEARD: Well, except it's a high pressure system.

DR. WALLIS: And you don't trust the check valve.

MR. BEARD: No, not on a reactor coolant pressure boundary I don't.

DR. WALLIS: No, you don't. Okay.

MR. BEARD: That was the end of my prepared remarks. Rick Wachowiak is now going to give you a brief overview of the PRA, and explain to you how we get to that wonderfully low number.

MR. WACHOWIAK: All right. Once again, my name is Rick Wachowiak, probabalistic risk assessment lead for the GE ESBWR. So let's just quickly go through an overview of what we've done for the PRA, and what the results are.

For internal events, which would be any of the LOCAs and transients, those sorts of things, with power operation we've done a complete Level I accident prevention, or core damage prevention; Level II, severe accident mitigation, and Level III, off-site consequence PRA. The Level III we had to use an assumed site, since we don't actually in the DCD phase you don't actually have a site to work with, but we picked the bounding parameters.

For shutdown, we did an internal events only PRA. However, we've gotten some feedback from the Staff that said they would like to see more on the external events, so we're in the process of getting that information to them.

We did not do a Level II for the shutdown, mainly because almost all of the shutdown core damage frequency occurs in mode six, which is the refueling mode, which there is no containment. So the containment is open there, and there wasn't really much reason to look at the containment for the other modes.

External events non-seismic, we've done screening analyses to show that the things like fire, flooding, high winds don't introduce any new or interesting phenomena that we haven't already addressed in the internal events, and they don't really impact the risk level for the plant. And for seismic, we've done a seismic margins analysis on our safety-related system. Once again, determined that there really aren't any outliers there that would tend to drive risk any different than what we would expect by these other analyses.

DR. KRESS: Level II, did you use MAAP?

MR. WACHOWIAK: Where we used MAAP was for determining the source terms for the off-site consequences. For determining the phenomenological probabilities, we used various combinations of CFD calculations and other codes that were benchmarked against experiments, like the IET test and various things like that to determine the phenomenological probabilities. So in terms of determining what's the probability of a containment failure during a DCH event, we did not use MAAP for that.

DR. KRESS: You used something like ROAAM.

MR. WACHOWIAK: ROAAM, yes, for that. Where we used MAAP was in the other parts, where if we did have one of these events, what is going to be the source term that we would feed into the Level III PRA.

DR. KRESS: And Level III you use CRAAC?

MR. WACHOWIAK: MACCS.

DR. KRESS: MACCS.

DR. POWERS: When you use something like ROAAM, my recollection is that requires judgments on distribution functions, for which nobody has any physical experience, like the fraction of cladding that's not oxidized in a core melt-down accident and things like that. How do you come up with distributions for things like that, usually for a plant that's never been built, and certainly never been melted down?

MR. WACHOWIAK: One of the things that we did was we looked at previous ROAAM applications for things, such as the AP-1000, and instead of trying to pick the entire distribution and work with the means and other various convolutions of different distributions, we picked parameters that were at the end of the distribution. So we did all of our analysis based on the high confidence values.

DR. POWERS: Meaningless distribution is

–- taking the ends of a meaningless distribution is still meaningless.

MR. WACHOWIAK: I understand, and the way that the ROAAM process addresses that is by taking the analysis and the results, and presenting it to several different reviewers and addressing the comments through expert opinion. That's how the process works, and as we get into this, we can discuss more on the process of the distributions that are used.

DR. POWERS: I bet we do.

MR. WACHOWIAK: Okay. I want to go over a couple of definitions that we used in the process, just so everybody's on the same page. For core damage, it's defined as a peak clad temperature of greater than 2200 degrees F. However, for the DCD purposes, for certification purposes, we used core uncovered as a surrogate for core damage, so we've got some margin there. Exactly how much, we didn't attempt to calculate that. So core uncovered is what we used as our surrogate. For containment failures, we included any failure of the containment and uncontrolled release, and we also included any containment venting into the large release category, or into the –- yes, into the large release category.

DR. KRESS: You looked at all containment failures, like early and late, or did you --

mR. WACHOWIAK: We looked at early and late. However, at this point, we haven't really made any distinction between an early failure and a late failure. We included all of them in our category. Now one of the things we may want to look at as we go forward with this, there are some of the containment failure modes that are occurring very late, like out in the third, fourth, fifth day, and we may not want to call those venting releases on the fourth day. We may not want to call that a containment failure.

DR. DENNING: Do you have any bypass scenarios in which the passive systems are providing the bypass route?

MR. WACHOWIAK: A sequence where the containment or where the passive system itself is the cause of the bypass? We've looked at that, and determined that that would not be a significant -- anywhere near a significant fraction of the containment failure probability, so we didn't explicitly treat that.

DR. WALLIS: Are your PCT bigger than 2,200? That's for short-term transient, which you can damage the core by holding it at lower temperatures for a long time. Why is that not part of your definition of core damage?

MR. WACHOWIAK: Once again, what we used was in the ASME standard, that says that if you used a detailed code for calculation, you can use 2,200. If you used a less detailed code, you can use 1,800. However, what we really did was we looked at core uncovery, so we --

DR. WALLIS: There are other ways to damage the core.

DR. DENNING: Yes, but you can't melt the core down.

MR. WACHOWIAK: You can't melt the core if it's covered.

DR. DENNING: I mean, you could damage fuel, but you're not going to --

DR. WALLIS: You could damage the fuel, right?

DR. DENNING: Yes, but the -- true. But then you've got --

DR. WALLIS: You don't melt the core --

DR. DENNING: So you get some release of radioactive material to the pool. I think it's -- melting fuel is important, I think.

DR. POWERS: You very seldom melt fuel in any case. You liquify fuel.

DR. DENNING: Well, some eutectic liquid formation or something.

DR. POWERS: You liquify fuel with a -- and it's not really a eutectic interaction.

MR. SIEBER: If you get to that temperature, your plant is sort of messed up anyway.

MR. WACHOWIAK: It's probably recoverable.

DR. RANSOM: Core uncovered, is that a collapsed liquid level?

MR. WACHOWIAK: What we've done to this point, it's a collapsed liquid level.

DR. RANSOM: All right.

DR. WALLIS: Well, PWRs uncover for quite a long time in a LOCA, don't they?

MR. WACHOWIAK: And as Alan pointed out, the existing BWRs that are out there right now uncover the core, a third of the core for quite a long time during their design-basis analysis.

DR. POWERS: You have to be careful about whether you're talking about collapsed level or not.

MR. WACHOWIAK: In our cases, we have been using the collapsed level.

DR. POWERS: I got that impression. And so you're not really --

mR. WACHOWIAK: We're not really

uncovering the core.

DR. WALLIS: So that's the only way you can get any damage at all, is by having these very conservative assumptions?

MR. WACHOWIAK: Well, that is one of the advantages.

DR. DENNING: Well, he didn't really say that. I mean, if you look at the situations in which you do get the water level below the top of the core, it could be in those situations, it's going to be well below the top of the core. I mean, we just don't know the answer.

MR. WACHOWIAK: And you don't know the timing either, so in my estimation, we probably would not change the core damage frequency by very much if we went to the trouble to use very sophisticated computer codes with a lot of other analyses to show. But as we get to where the results are, we'll see what it takes to get to core uncovered, will probably proceed beyond core uncovery.

We did include a comprehensive systems analysis in this PRA. Someone asked earlier about if we included the non-safety systems. Yes, we did. We included 24 systems which included both the safety-related front line systems, the non-safety-related front line systems, the ones that actually provide cooling to the core, and also any support systems that would be needed to keep those other front line systems working; included all major components, and we had fully linked support systems, which means it's the full fault tree model all the way down to the components in the support systems; included intra-system common cause as most PRAs do. However, for Squib valves, we did include an intra-system common cause on the Squib valves for systems where we might use the Squib valve in more than one application, because it is so important to our passive safety systems.

MR. SIEBER: Do you have any components that are new enough in design concept that you really don't have failure data for? And what did you do?

MR. WACHOWIAK: Well, new enough in concept or in magnitude that the data doesn't apply, and we don't think we're at that point. The Squib valves that we have in the GDCS system are just slightly bigger than the Squib valves that are now being used in the standby liquid control systems of other BWRs. The closest thing we might have is the DPV-type depressurization valve, Squib valve there, and we have tests that we've done with that type of valve.

MR. SIEBER: Okay. Everything else is common stuff, like heat exchangers, pipes, check valves.

MR. WACHOWIAK: Right.

DR. DENNING: Well, I think there's an important thing we have to worry about though, Jack, and that is, you're taking a lot of credit for passive systems, and we have to really be sure that those passive systems really function for all the various conditions that maybe we haven't thought about.

MR. SIEBER: Yes, they're driven by pretty small DPs sometimes, and you're counting on a certain flow rate which you may not achieve. Understood.

MR. WACHOWIAK: Yes. And in some cases, there's a big DP, other cases as you move out along the time curve, the DPS get less. We're also moving farther and farther away from the capacity that we have. I'm sure we'll get into that discussion. We've already started that discussion with the Staff.

MR. SIEBER: Of course, on the other hand, the energy that you need to dissipate is getting lower, and lower, and lower.

MR. WACHOWIAK: As time moves on.

MR. SIEBER: As all these driving forces

are getting smaller.

MR. WACHOWIAK: That's correct. For our containment performance, for any systems level or any systems information that needs to be passed forward into the containment analysis, we've directly linked the Level I and the Level II, so we don't have that arbitrary interface that some PRAs have. And as we mentioned earlier, for determining the phenomena probability, such as what's the probability that we're going to fail the containment during a DCH or things like that, we used the ROAAM process, and used the high confidence rather than mean values when we did that evaluation, or those evaluations.

We talked a little bit about data a second ago. I just want to point out a few things about our data. Our initiating events are all based on the operating fleet, so we took NUREG 57.50, and looked at that. So we didn't try to incorporate some of these new features that we have in the feedwater system that Alan was talking about, where we think it's much more reliable, better than what's out there in the fleet now. So we did not incorporate those types of things into our initiating events, anything that was better. Some things we did take out, if we really knew that there wasn't a failure mode there any more. We took those out.

Generic data we picked from the URD for the most part, the EPRI requirements document. However, we did adjust for things like environmental conditions for the check valves, and GDCS valves that are now going to be operating in possibly a steam environment or a high temperature environment, versus right now the Squib valves that we see in standby liquid control. The environment is different, so we increased the failure rates for those sorts of things. We also looked at long test intervals.

DR. WALLIS: How do you do that? These are just guessing that it's going to be twice as bad, or do you have some rational basis for deciding when you change the environment, how this failure rate will change?

MR. WACHOWIAK: We used a guess, and then we performed sensitivity analyses to show that it wasn't important.

DR. WALLIS: That's not a very secure way of doing things.

MR. SIEBER: Best you got here.

MR. WACHOWIAK: And a guess followed up by sensitivity analyses.

DR. WALLIS: Because, I mean, it might be that the steam environment does something drastic to some kind of --

mR. WACHOWIAK: Well, they're qualified for operating in that condition, so we're starting with something that's qualified to operate in that steam condition, but we're looking at data that was not taken in that same scenario.

DR. WALLIS: You didn't have to use a guess, so I --

mR. WACHOWIAK: It would be better. We've also adjusted things for long test intervals. Most of the data that's in the URD is associated with equipment that's tested quarterly. Since we have some valves that are in locations that we won't see for two years, because they're inside of the containment, and that would be the refueling cycle, we adjusted the failure rates to account for the longer test interval. And with that, we used a method that - I don't remember the name of the method, but it's a method that's typically used for adjusting data for longer test intervals. Yes, a structured guess. I don't -- it's a process that's been used in other PRAs for adjusting data for that.

DR. WALLIS: It probably actually has an equation that goes with it.

MR. WACHOWIAK: Yes, it does. We also, in looking at operator actions in the design certification, we've used screening values where we think the lower bound reliability for our operators, and we tried to use a rule of thumb, things such as if the action had to be taken very early, like in the first 30 minutes, we wouldn't count on the operator. If it had to happen in the first hour, we'd give him some credit, in the first day a little bit more credit, out after the first day a little bit more credit beyond that, but there's still screening values.

DR. WALLIS: But the reliability of the operator actions is pretty high, isn't it here, the probability of the wrong action is 1 percent or something typically, isn't it?

MR. WACHOWIAK: For actions that would need to be taken between one hour and 24 hours, 1 percent is approximately the value that we use.

DR. WALLIS: That's all right if the operator really knows what's going on, but if he misunderstands the accident, then he can do all kinds of things. If he misunderstands what's happening, he's much more likely to cause an error than him actually knowing everything and doing the wrong thing.

It's when something happens to confuse them in the context --

MR. SIEBER: Yes, but with a passive system there isn't too much for the operator to really screw up.

DR. DENNING: He might screw up the passive system. That's the --

MR. SIEBER: Yes, but that would be a mispositioned valve or something like that.

MR. WACHOWIAK: And I want to be clear on what we did with the operator actions for post accident. We've included the types of things where the passive, or the automatic systems didn't work, and the operator is backing up that automatic system. We've included those errors. We did not include errors of commission as other PRAs that are done for nuclear power plants.

DR. POWERS: But, I mean, how can you not do that? I mean, that seems to be the downside of having a hands-off accident scenario where your operators don't have to do anything. The truth of the matter is the operators will do something. I mean, that is in their nature to do stuff, and I don't know how you come up with a 1 percent error rate on errors of commission. I mean, I have no idea how to do the estimate.

DR. WALLIS: I think what you have to do, make it very difficult to do that, and make it so that the system is -- you can't interfere with it once it's -- gravity is working. You cannot do something to screw it up.

MR. WACHOWIAK: So, for example, we do have an example of that in our safety systems. In the combination of ADS GDCS, once that goes into its operation, it can't be overrided by the operators. It continues to its full -- once it's been activated, automatically it continues to its completion.

DR. WALLIS: You can't cut-off the Squib valve or something.

MR. WACHOWIAK: Right. And we've set it up so that you -- so we've attempted to address that in the design, but once again, as other PRAs for nuclear power plants, we have not fully addressed the errors of commission issue.

DR. WALLIS: That's errors of commission by the designer.

DR. SHACK: You have to remember, these aren't real numbers. I mean, this just demonstrates that you've got lots of redundancy in this --

DR. WALLIS: You're telling me PRAs are

not real numbers. Is that what you're claiming?

DR. SHACK: Three times ten to the minus eight.

MR. WACHOWIAK: What we wanted to show in the end --

DR. WALLIS: When you're down to design here, then it means a design fault could be the limiting factor on PRA, if there's something which you overlooked in the design. I don't know if it's a ten to the minus six probability of that, but there must be some probability of that.

MR. WACHOWIAK: And, as a matter of fact, we have included that in some of the areas, especially in the digital instrument and control area, we've looked at design errors in the software systems, so those we've included in the analysis.

What we wanted to show with our data values is that the low CDF we have with the ESBWR is due to the design, the redundancy and diversity in the design, and not a direct consequence of just saying it's a new plant so we have better numbers.

DR. WALLIS: I'm thinking about design is using degrees Centigrade instead of Fahrenheit, and sizing a -- somehow it slips through everything, nobody catches it. Some engineer calculates the pipe size and everything seems right, and the computer calculates it right because something is wrong about that, but in fact, it's passed all the inspection and still the wrong size.

MR. WACHOWIAK: Somebody signed when they should have co-signed, right.

DR. WALLIS: Whatever.

MR. WACHOWIAK: But certainly those are below ten to the minus eight.

DR. WALLIS: Wait a minute.

MR. WACHOWIAK: Those types of things have not been treated in past PRA applications like this, and we're trying to -- our attempt it to do this at the, what we call the state-of-the-art, what's being approved.

DR. WALLIS: But then you're going to tell me that an error in TRACG is likely with a factor probability ten to the minus -- don't tell me that.

DR. SHACK: You could have left off the decimal point.

MR. WACHOWIAK: On this one? Well, I did as I moved down to the next one, I left them off.

DR. POWERS: You were very proud of that point, too. You had to work hard to get that --

MR. SIEBER: I take it external events is seismic, fire.

MR. WACHOWIAK: Seismic, fire, flood.

MR. SIEBER: Flood. You actually analyze those or are you just saying --

mR. WACHOWIAK: Okay. What we did, I mentioned that on the first slide, for the flood analysis, that was as close to actual -- the details in the internal events PRA of any of the external events screening analyses that we did. We came up with a very low number there. It shows about in this decimal point out here, so that's low.

When we looked at fire, we looked at it in a very conservative manner with very bounding assumptions and found that fire itself, those scenarios don't come anywhere near -- with the bounding assumptions, they're out here, so they don't have a large contribution.

MR. SIEBER: Yes, you don't have too many things that have to operate.

MR. WACHOWIAK: Don't have too many things that have to operate, and plus --

MR. SIEBER: Since fire doesn't have much of an impact.

MR. WACHOWIAK: That's correct. And the other thing that's happening here is that we now know when we're building this plant what the right way to design for electrical separation for fires is, versus previous plants that were built or designed 50-60 years ago, or whenever they were designed, they didn't have the advantage we have now of knowing how to prevent fire interactions.

MR. SIEBER: Now the seismic, if I read properly, it's designed for a hard rock site southeast or better?

MR. WACHOWIAK: Central, yes.

DR. DENNING: But they did a margin study instead of a seismic PRA, so they don't know what --

MR. SIEBER: Okay. So you don't really know.

MR. WACHOWIAK: Don't really know.

DR. DENNING: You didn't --

MR. SIEBER: That's the design basis. You have to find a site that's like that.

MR. WACHOWIAK: We did it based on the likely customers that we'll see shortly here.

DR. WALLIS: How much did you adjust this for the fact that this thing has never been built?

DR. DENNING: You take it for what it's worth. And what it's worth is, it says they did a very good job of designing this system, and that's what you believe, and you don't believe it's ten to the minus eight --

DR. WALLIS: It's not practice, it's design.

DR. DENNING: Right. And give a question about you did a sensitivity study where you only credited Class I systems. I don't see it in here, but I saw it in something else.

MR. WACHOWIAK: Right.

DR. DENNING: And the results of that was?

MR. WACHOWIAK: When we only credited our safety-related systems and what we calling our RTNSS systems, the Regulatory Treatment of Non-Safety Systems, when we included those, the CDF was somewhere around ten to the minus five, four times ten to the minus five.

DR. DENNING: I think it was about -- I wanted to point out that it doesn't satisfy Mary Druin's criteria, believe it or not.

MR. WACHOWIAK: Because it's not better than existing plants?

DR. DENNING: No, it's that she wants ten to the minus five, but only with safety class --

MR. SIEBER: At least one of the members objects to that criterion.

DR. DENNING: Yes, well at least one. I'm pointing that out, not to say --

mR. WACHOWIAK: Is that in a published memo somewhere?

DR. DENNING: It's nothing official.

MR. WACHOWIAK: Okay.

DR. DENNING: It's just part of the process of developing technology neutral and various concepts people are thinking of.

MR. WACHOWIAK: Okay. That's good to know.

DR. DENNING: But don't change your design as a result of it.

DR. WALLIS: We talked about this earlier, but when you only consider safety systems, you get a pretty high -- you get a factor of ten to the fourth difference when you --

mR. WACHOWIAK: Well, let's put everything on an even --

DR. WALLIS: Is it fair --

mR. WACHOWIAK: -- on a level playing field here. If you take an existing BWR today that has a calculated core damage frequency of ten to the minus six and eliminate all the non-safety systems from that, they're not going to be anywhere near ten to the minus four, so the PRA analysis is meant to look at all the different things that you have available to you, and the numbers are based on that, and the goals are based on that.

SPEAKER: Just one comment, Rich. That was not the CDF that Mary was -- it was meet the safety goals with safety-related equipment doesn't imply that needs to be ten to the minus five core damage frequency.

DR. WALLIS: Well, I'm just puzzled. Why do you bother to call anything a safety system if you don't need it in the PRA? It doesn't matter what it is in the PRA. Why do you bother to have a Class I if it's -- what's the difference? Why have it?

MR. WACHOWIAK: It's being directed by different sets of regulations.

DR. WALLIS: Why? The PRA is the bottom line, who cares?

DR. POWERS: When the regulations were written, the PRAs were only not a bottom line, they didn't actually exist.

DR. WALLIS: Today is today. I'm just asking why today if the PRA is the great measure of everything, you would want to have the different classifications. It doesn't seem to make so much sense as it used to in the old days.

DR. SHACK: From your old U-Graph it's three times ten to the minus eight for the base case safety, plus RTNSS is four times ten to the minus five. No operator credit is two times ten to the minus six. Multiply the Squib failure by five, it's one times ten to the minus seven. The Squib failure by ten is three times ten to the minus seven.

DR. WALLIS: Well, when you have all these different numbers, what's the basis for making a decision?

DR. POWERS: Ten to the minus seven, ten to the minus eight, and ten to the minus nine are all the same numbers in PRAs. There aren't different numbers.

SPEAKER: Well, I think if you can make it low enough, you don't have to worry about safety culture is the --

SPEAKER: No, if you make it low enough, that's all you have to worry about.

MR. SIEBER: If it's low enough, it's hard to make a change under 1.174.

DR. WALLIS: Well, to bring up Rich's point, if you make it zero, then something else --

SPEAKER: You could build another reactor and still call it a small change.

DR. WALLIS: You can make it zero, and something else like security becomes your dominant safety consideration.

MR. WACHOWIAK: Right. And one of the things that we wanted to do for this whole design process is we wanted to take the experience that we've had from doing risk analyses on existing plants and apply it early in the process of the design, so what we've tried to do is we tried to eliminate those things that were causing risk-significant problems in other plants. And the calculated value comes down because the things that we've identified as problems before are designed out of this plant. They're not there to cause us problems any more.

DR. SHACK: Why are there dents in the bottom of your vessel?

MR. WACHOWIAK: Why are there dents?

DR. SHACK: Is that where you drop --

mR. WACHOWIAK: I think that's where they did the ASME stamp on the --

DR. SHACK: Why do you guys always leave out that forest that's really at the bottom?

MR. WACHOWIAK: I wanted to point out a couple of things here that possibly Alan didn't hit in his other presentation, just for the containment highlights. One, he talked about it finally in the end, is this deluge line, that if we were to happen to get the core out of the vessel, how do we keep water on there, and we'll talk about that a little bit more in the next slide.

The other thing that wasn't really talked about yet was this, what we call the MCOPS, or Manual Containment Over-Pressurization System. It's really part of our containment inerting system, but in the event that everything fails, failure mode on something that has no failure modes and things like that, we still have the capability to reduce the amount of non-condensibles in the containment, and keep it from getting to an uncontrolled release.

DR. WALLIS: So what happens with that hole there, what do you do with that hole?

MR. WACHOWIAK: It's not really a hole. It's the Containment Inerting System. There's a 12-inch pipe that's used to actually inert the containment during things, so you could open that big valve if you needed to. But in our cases, really what we would use is the normal operational vent line which is a 2-inch line, because if we vent off non-condensible gases over a long period of time, the containment strength is still such that --

DR. WALLIS: Is that line now part of your pressure containment system, is that part of the containment, that line?

MR. WACHOWIAK: Yes, and it always has been.

DR. WALLIS: Out to the valve.

MR. WACHOWIAK: Out to the valve. And we've specified from the valve to the stack it needs to be able to handle severe accident conditions.

DR. KRESS: I'm glad to see you don't have a sump with a screen.

DR. WALLIS: That's what that red dotted line is.

MR. WACHOWIAK: That we don't have a what?

DR. KRESS: Sump.

MR. WACHOWIAK: Yes, well there is an equipment drain sump, but not the sump that you're talking about.

DR. KRESS: No recirculation.

MR. WACHOWIAK: No.

MR. SIEBER: Well, there is, but it's --

mR. WACHOWIAK: Well, the sump is up here.

DR. WALLIS: Well, let's talk about debris.

MR. WACHOWIAK: Okay.

DR. WALLIS: When you have this big break, where does all the debris go? Does it go into the suppression pool, does it go through the vents, is there chance that the debris will get up into those condensers and block them up?

MR. WACHOWIAK: We have --

DR. WALLIS: What happens to all the debris, which is flying around with a large LOCA?

MR. WACHOWIAK: The insulation that we use on the vessel itself is the reflective metal-type of containment or of insulation, which we wouldn't expect to provide very much debris.

DR. WALLIS: If it does, it's pretty robust; if it gets in a hole it can block it up.

MR. WACHOWIAK: We have screens keeping debris out of the GDCS pool, and the inlet to the PCCS heat exchanger is also protected, I believe, from debris, so we've looked at those sorts of things. The equalizing line does have a debris screen on it, but once again, we wouldn't expect a lot of debris to be coming through here, but it might.

DR. WALLIS: It might go down into that well there.

MR. WACHOWIAK: Into the well here, but as long as it's not out here, we're okay.

DR. WALLIS: So there is a consideration of debris in the safety evaluation at this plant? I think there has to be.

MR. WACHOWIAK: In the design, yes.

DR. WALLIS: Well, in the safety evaluation, too. Is there at least a discussion or an analysis of what happens to the debris? It's nice to know it's all reflective metal.

MR. WACHOWIAK: Those deluge lines, what they actually go down to is this device we call the BiMAC, Base Mat Internal Melt Arrest and Coolability. It's a type of core catcher that's actually built into the floor of the lower dry well. The way that it works is that if we were to get core material down into here, this actually, it is built this way so that it has a cup, if you will. The lid is just a walking surface, it's not any sort of barrier. Yes, so you could walk on the corium, is that -- so once we detect that we have core material down there based on thermal couples embedded in the material down here, we would open this line, and any water that's in the GDCS pools would come down through and be distributed amongst pipes that are laid out parallel covering the entire floor, spill out over onto the top, which would then cool the core from the bottom, from the sides if it gets there, and to the top, and then there's also provision made so that after a few hours when the water is gone, it can go into a natural circulation mode.

DR. POWERS: Have you just been paid off by the people doing steam explosion research? Is that --

mR. WACHOWIAK: What's that?

DR. POWERS: Have you just been bought off by the people doing steam explosion research? Is that why you put this water in there?

MR. WACHOWIAK: Have we been bought off by them?

DR. POWERS: Yes.

DR. KRESS: They want to do some more.

DR. POWERS: Yes, they want to do a lot more here.

MR. WACHOWIAK: Okay.

DR. POWERS: They've got alternate contact modes, they've got embedded wire injection. They've got all the modes here.

SPEAKER: Well, I'm sure ROAAM came up and said it was wonderful.

MR. WACHOWIAK: We looked at the

possibility of steam explosions from inside these pipes. That's been looked at. I don't know that we included that part in the report, but that question did come up, and we've looked at that. The heat transfer rate that's going on through here into the different sections is low enough where we wouldn't expect that to be a problem.

DR. POWERS: I'll remind you that at the Beta facility in Germany, they also did that calculation, and we stunned to discover that maybe calculations aren't 100 percent accurate.

MR. WACHOWIAK: And that was the specific test we were talking about.

DR. WALLIS: With all that water there's no recriticality?

DR. POWERS: Not when it's all --

mR. WACHOWIAK: No, not in this geometry, and plus there's probably a lot of -- if you've melted that much core to get down there, too, you've melted as much control rod in addition to that. Plus, we have the standby liquid control that's been injected earlier on.

DR. POWERS: See now, if you melted the boron and it oxidizes into boric acid which boils at 1830 Kelvin, and the core melts - how much boron do you have left in this core?

DR. WALLIS: Boil after the control rods?

DR. DENNING: It's not needed for the criticality. I mean, you have to have an optimum configuration with this enrichment.

MR. WACHOWIAK: It's not the one we want to see, I'll tell you that much.

DR. POWERS: Not a good fueling plant at all.

MR. WACHOWIAK: I'm trying to think. One of the questions that we didn't get to here that I would have thought of, how do we have water still in the GDCS pools if we're going to use it for this? The main reason is, if we've used the GDCS pools to put the water in the vessel, you don't melt the core. The only way to melt the core is to keep the GDCS out of the vessel.

DR. WALLIS: Isn't there going to be water down there anyway?

MR. WACHOWIAK: No.

DR. WALLIS: No?

MR. WACHOWIAK: Because of steam explosions in this area when the core comes out of the vessel, we've done the best we can of avoiding having a large or a deep pool of water in the lower dry well before the core comes out of the vessel. There are a few accidents that have –– maybe are calculated 1 percent or less of our severe accident, start out with a large pool of water down here.

DR. WALLIS: I'm confused. I thought you said that in these accidents the hole at the bottom of the containment filled up with water.

MR. WACHOWIAK: Okay. In our design-basis evaluation accidents, so if we have an accident where we're looking at a pipe break of one of these lower pipes - yes, that will happen. However, as we know from doing PRAs for many, many years, pipe break scenarios aren't the ones that drive risk. It's other scenarios that drive risk, so most –– the vast majority of our sequences that lead to a core damage event have very little water down here.

DR. WALLIS: It's dry down there.

MR. WACHOWIAK: It's dry down here, and we've done what we can to ensure that it's dry down there just so that we can avoid the steam explosion.

DR. WALLIS: That's why there's still water in the ––

mR. WACHOWIAK: That's why there's still water in the GDCS.

DR. POWERS: Well, even if you had an ex-vessel steam explosion, what in the world could it possibly do to you?

MR. WACHOWIAK: We'll touch on that in a one-liner at the end, but I'll just bring it up now. We'll get there quickly. I think I'm close to done.

Okay. One last thing I want to talk about during shutdown, if we were in the refueling mode, that's why the head is gone now and there's water up here, and we were to have some sort of an event that caused a LOCA in the shutdown, the reason that the shutdown core damage frequency is very low is that when we dump the water that's already up here and what's in the GDCS pools in, we end up filling the containment all the way up this high. You end up –– it takes days to melt the core in a shutdown event where we have some sort of loss of integrity. So the containment itself acts as a separate backup containment vessel.

So talk about severe accident threats in the failure modes that we analyzed. Direct containment heating event - if we were to have the core melt through the bottom of the vessel while the vessel was still at high pressure, you could see direct containment heating, which might involve an energetic failure of the upper dry well or a liner failure of the lower dry well and connections between those. When we went through the evaluation, the energetic failure of the upper dry well, the pressure suppression features of the containment preclude this energetic failure. We don't generate a high enough pressure peak to challenge the containment in a DCH event. And what we have also seen is that the liner failure, due to the high temperatures, we also don't see a liner failure due to temperature or penetration failures due to temperature.

The other possibility is this ex-vessel steam explosion we talked about. We have a deep sub-cooled pool of water below the vessel. You drop core material there. The conditions are right, it won't always happen, but the conditions are right for having some sort of a steam explosion, so we looked at the strength of the pedestal, and what we see is that if the pool of water is saturated, or if it's very shallow, like below 500 or 770 centimeters, it's not going to fail the pedestal.

The other problem that we looked into was in the BiMAC, all those pipes, if we have some sort of an impulse load down into that, that we might crush some of those pipes. And once again, as long as we don't have a deep sub-cooled pool of water, we don't have to worry about that.

DR. WALLIS: I'm sure someone's going to ask you about E being as a threat to public safety.

DR. POWERS: Let me ask you about that. I mean, I'm quite frankly stunned that you could even threaten the pedestal. Were you working at the Hicks Menze limit or something on these?

MR. WACHOWIAK: I'm sorry?

DR. POWERS: The Hicks - you were taking the thermomatic limit on these steam explosions?

MR. WACHOWIAK: Yes. We were involving --

DR. POWERS: Hicks Menze I could understand.

DR. KRESS: It's really more like 3 percent of that.

DR. POWERS: Well, that's 30 percent of that, but 3 percent is the kind of numbers I would --

DR. KRESS: Hicks Menze is almost 50 percent.

DR. POWERS: Well, it's about 48, 49.

DR. KRESS: Okay.

MR. WACHOWIAK: And to talk about these probability distributions with -- when we got into looking at that, really with the deep sub-cooled pool of water, the tail-end of the impulse curve just met with the front end of the containment failure curve, and because they overlapped we just said okay, deep sub-cooled pool, we'll call it a containment failure.

DR. POWERS: Yes. I mean, I can understand how you do that. I mean, how you would come up to that conclusion. That's fine.

MR. WACHOWIAK: With the rest of the things, we didn't see an answer.

DR. POWERS: The pipe crushing is the more real issue. I mean, we've actually broken things underneath steam explosions because there is a pretty good requel.

MR. WACHOWIAK: Right.

DR. POWERS: In real tests we would bust things.

MR. WACHOWIAK: Finally, on the base mat melt penetration, in the past like with the ABWR, the certification just used the spreading criteria. If it's spread out enough, and you put water on it, that was okay. What recently in the last 10 years, that's been called into question - does it really spread enough, does it really have enough coolability from the top? So in order to go ABWR method plus, we added the BiMAC so we can get cooling around all sides, so that we think we have a double protection there now, just not only the spreading, but also from cooling from below.

DR. WALLIS: Is there any quantitative assessment of these risks, quantitative assessment of things like base mat melt penetration?

MR. WACHOWIAK: The ROAAM process gives us this number that we used in the analysis, so we said it has this probability of failing. The question that came back is, how good is the floor if you don't have the BiMAC there, and we're working on answering that question.

SPEAKER: We didn't answer it in our initial submission.

DR. POWERS: One of the things that you really want to think about is cooling core degree is a tough thing to do. What you're really worried about is keeping the efficient product release down. Water on top is a wonderful thing.

MR. WACHOWIAK: Right.

DR. POWERS: Water underneath is useless for efficient product retention.

DR. KRESS: In fact, it enhances it.

MR. WACHOWIAK: Remember, the way it works is the water comes down through, force conductive cooling on the bottom, keeps going, and then pours on the top, so when this device works, it actually gives you both of those.

DR. POWERS: I'll believe that right after I see it demonstrated.

DR. WALLIS: You want to see it demonstrated?

MR. SIEBER: I don't want to see it demonstrated.

MR. WACHOWIAK: It's about a 40 percent void fraction is what we're expecting on the longer tubes. Basically, just want to get to the conclusion here. When we went through our ROAAM process, we determined that with all those different threats, the containment failure was really going to be in the physically unreasonable range. We think we've addressed all the different energetic phenomena, and the things that can really challenge the containment. The rest of that, I --

DR. SHACK: What's a complement?

MR. WACHOWIAK: I'm sorry. What?

DR. SHACK: I don't know what a complement is.

MR. WACHOWIAK: A very nice severe accident. We've addressed -- so why is the ESBWR risk numbers coming down low? We talked about this, several different things, but the main reason is due to redundancy and diversity. We didn't really touch on the instrument and control systems, or the control and instrumentation systems, but we have five of them installed in the plant that do various things. There's a safety-related, there's a non-safety backup, there's the feedwater control systems, there's the on-safety systems, and then there's the ATWS prevention systems.

In order to get the core damage just based on INC system failures, you actually have to fail three of those systems, and they're independent. They're on different architectures. They don't have ways that you'd have common mode failures.

If we look at the top cutsets in the PRA, we see a lot of common cause batteries, common cause Squib valves. You don't really see any individual components anywhere in the top cutsets, so you have to get the common mode failures, possibly these design things or whatever before you get to a core damage event.

One of the other interesting things is if we have the SBO plus, loss of all AC and all DC power, we still survive that because the isolation condenser goes into service on its own in that scenario, and it doesn't result in core damage. The containment failure itself, we've seen in past designs where containment failure would lead to an environment that would take out the systems that are needed for continued core cooling. In the ESBWR that doesn't happen, so if we do have a containment failure, it really is based on how long it takes to boil off the water that's already in containment, and that's greater than 72 hours. Containment can be flooded to above the core using passive systems is another thing.

DR. KRESS: About that, what is the diameter of this vessel compared to say a PWR, compared to ABWR?

MR. WACHOWIAK: The diameter of the vessel, it's the same diameter.

DR. KRESS: As the ABWR?

MR. WACHOWIAK: As the ABWR.

DR. KRESS: How about the AP-1000?

MR. WACHOWIAK: I don't know the answer to that.

DR. KRESS: Well, the reason I'm asking is that the effectiveness of flooding the vessel external to the thing depends on the diameter of that vessel. It also depends on where there's a forest of things down there, and how well the steam can get away, so I was wondering how you know how effective that would be, and is that to keep the core inside the vessel? Is that what it's for?

MR. WACHOWIAK: No, that's not what we're counting on this for.

DR. KRESS: I see.

MR. WACHOWIAK: What we're counting on this for is if we do have pipe breaks somewhere in the containment that we could get a challenge to the water level in the vessel, we can flood the containment up and provide core cooling.

DR. KRESS: Okay. I was just --

mR. WACHOWIAK: We're not taking any credit for in-vessel retention.

DR. KRESS: Okay. I was misinterpreting.

DR. WALLIS: Now these common cause failures are most likely due to human action, core maintenance, core connection, somebody connected up the batteries in some incorrect, or didn't maintain them properly so that acid leaked out and corroded something, or something. That's what you look for in common cause, some human action which was common to all the batteries.

MR. WACHOWIAK: Well, I don't know if it's only due to human action, but it's something that's common.

DR. WALLIS: That seems to me, you know, if you're talking about ten to the minus ninth or something, then that seems to be just as likely as this --

mR. WACHOWIAK: But we have to remember on the --

DR. POWERS: We have established Greek letter method. The Greek letter method is the way you --

DR. DENNING: There's a magical method, Graham.

DR. WALLIS: Well, that's just a symbol you use in the math for common cause failure.

DR. POWERS: No, it's not.

DR. WALLIS: You only put numbers on it.

DR. POWERS: It has a number.

MR. WACHOWIAK: It has a number and it's supported by data.

DR. WALLIS: Well, let's not go that far.

DR. POWERS: It has an accepted number.

MR. WACHOWIAK: Okay.

DR. WALLIS: This is why, for instance, you get recalls of automobiles, is a common cause failure of something which is recognized after experience.

DR. POWERS: This is why NRC is the world leader in common cause failure probability estimates.

MR. WACHOWIAK: But we have to remember, though, typically you're not going to get a core damage event from a single common cause failure. It's going to have to be multiple diverse common cause failure. They involve those kinds of common cause failures, but it's not if you have this one, it's core damage. That's not the case. You have to have that plus other common cause failures.

DR. DENNING: And I think the point isn't that they can accurately estimate the common cause failure. The point is that they've designed the system such that you've done away with the importance of single failures, so you're down into the noise of common cause failures.

DR. POWERS: Well, you an argue that that's true even for existing plants. Single failure you just don't kill plants, it's always multiple failures, and nearly always common cause failures.

DR. DENNING: In a well-designed plant, that's true, but you do find some single failures in those outliers that get you in trouble. But I agree with you. I mean, typically that's why our plants are safe.

MR. WACHOWIAK: Yes. Some of the other things, our containment ultimate strength is fairly high, 1.2 megapascals for the high confidence failure pressure. In most scenarios that we look at that involve a severe accident, we have .9 and less in the containment. Conditions for ex-vessel steam explosion, we talked about that. We do what we can to avoid those so that we don't have that phenomena. The containment we've shown can survive the DCH events. Once again, our various diverse depressurization systems keep us away from those scenarios that that could happen, but even if it did, we can still deal with it. And then we're not just relying on the melt spread and water on top for basemat melt attack. We've added an engineering feature to augment that.

So in conclusion, we believe that our report provides a comprehensive assessment of the capabilities. We've incorporated the risk insights during the design phase, and that's what helps drive our risk numbers down to this low range. And we meet all the goals with significant margin, and we think it's a very safe plant, with a good safety design.

MR. HINDS: That's the conclusion of our

prepared presentation today. We thank you for your time. If you have further questions for us --

DR. WALLIS: Thank you, that's very nice. We've heard this sort of thing before. What we now need to do is do some real work with subcommittees to look at the details of this, it seems to me.

MR. HINDS: Thermal hydraulic stability is the first one up for subcommittees?

MS. CUBBAGE: Yes, that'll either be in January or February for thermal hydraulic stability, and then we're also looking at a PRA subcommittee meeting also in the February --

DR. WALLIS: Are there any materials issues that need to be looked at?

DR. POWERS: One question I forgot to ask you is was the dry well, wet well through containment leakage in this plant?

MR. WACHOWIAK: It's similar to other BWRs. It's half a percent per day weight volume, or weight leakage. It's all the same. Okay?

DR. POWERS: Okay. Thank you.

DR. WALLIS: I'm very glad we finished on the quarter hour, the half hour. We're going to take a break. We don't need the transcript after the break. Thank you very much. We're going to take a break until quarter to four.

(Whereupon, the proceedings went off the record at 3:27:58 p.m.)