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NUCLEAR REGULATORY COMMISSION

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556TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARD

(ACRS)

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THURSDAY, OCTOBER 2, 2008

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. William J. Shack, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

WILLIAM J. SHACK, Chairman

MARIO V. BONACA, Vice Chairman

DENNIS C. BLEY, Member

SANJOY BANERJEE, Member

JOHN W. STETKAR, Member

J. SAM ARMIJO, Member

DANA A. POWERS, Member

SAID ABDEL-KHALIK, Member

MICHAEL T. RYAN, Member

COMMITTEE MEMBERS PRESENT (Continued):

OTTO L. MAYNARD, Member
CHARLES H. BROWN, JR., Member
HAROLD B. RAY, Member
MICHAEL CORRADINI, Member
GEORGE E. APOSTOLAKIS, Member

NRC STAFF PRESENT:

BRIAN HOLIAN
DONNIE HARRISON
MATTHEW DENNY
MAURICE HEATH
JIM MEDOFF
STEPHEN SMITH
BILL RUTLAND
PAUL KLEIN
MATT EWER
JOHN LENNING
RALPH LANDRY

NRC STAFF PRESENT (Continued):

HOSSEIN HAMZEHEE
MARK CARUSO
AMY CUBBAGE
MARIE POHIDA
ED FULLER

ALSO PRESENT:

DAVE CORLETT

MIKE HEATH

BILL ROGERS

BARRY SCHNEIDMAN

CHRIS MALLNER

MO DINGLER

STEVE BAJOREK

RICK WACHOWIAK

C O N T E N T S

P R O C E E D I N G S

(8:29 a.m.)

CHAIRMAN SHACK: The meeting will now come to order.

This is the first day of the 556th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the Committee will consider the following:

License renewal and final SER for the Shearon Harris Nuclear Plant, Unit 1;

Status of resolution of Generic Safety Issue 191, "Assessment of Debris Accumulation on Pressurized-Water Reactor Sump Performance";

Selected chapters of the SER associated with the economic simplified boiling water reactor design certification application;

Quality assessment of selected research projects;

Historical perspectives and insights on reactor consequence analyses; and

Preparation of ACRS reports.

A portion of the session selected chapters of the SER associated with the ESBWR design certification application may be closed to protect proprietary information applicable to this matter.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswamy is the Designated Federal Official for the initial portion of the meeting.

We have received no written comments or questions nor request for time to make oral statements from members of the public regarding today's session.

Mr. Cardell Julian, Region 2, is on the phone bridge line listening to the discussion regarding the Shearon Harris license renewal application. He will answer any questions directed to him during the Shearon Harris license renewal application review.

Also Mr. Jack Sieber, ACRS member, who was not able to attend the meeting today due to personal issues, is on the phone bridge line listening to today's discussions.

A transcript of portions of the meeting is being kept and it is requested that speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they may be readily heard.

Our first item is the license renewal application for Shearon Harris and Mr. John Stetkar will be leading us through that.

John.

MEMBER STETKAR: Thank you, Mr. Chairman.

We're here for the Shearon Harris license renewal application. We had a subcommittee meeting on May 7th. At the time of the subcommittee meeting there remained one open item on the safety evaluation report, two confirmatory items. So we're anxious to hear how those items were resolved.

And at the time of the meeting, we also asked the applicant to be prepared to discuss two or three additional technical issue that came up during our meeting, and to get the process rolling here, I'm just going to turn it over to Mr. Brian Holian, Director of the Division of License Renewal, for introductory remarks.

MR. HOLIAN: Good, thank you.

My name is Brian Holian, Director of License Renewal, and I'd just like to do a few introductions.

To my left is Dave Pelton, Branch Chief in License Renewal, who has responsibility for the Harris plant. Dave replaced Louise Lund, who is right behind you. Louise is in the ICS Candidate Development Program and is still in License Renewal and still assisting us.

To my right is Maurice Heath, who is the project manager for the license renewal application and will be doing the majority of the staff's presentation today.

I'd just also like to highlight a few of the technical branch chiefs that are in the audience that have helped with the review. We have Jerry Dogier, who is right behind me there, and he's responsible for one of the Technical Audit Branches in License Renewal.

We also have Donnie Harrison from Balance of Plant in NRR.

And Matt Mitchell from Component Integrity.

And Bill Rogers is acting for Raj Auluck, the other Technical Audit Branch.

With that, as was mentioned, we did forward the final SER, and both the staff and the applicant will cover the open item and the two confirmatory items and how they were resolved in the time frame from the subcommittee meeting to the final meeting.

With that, the applicant will lead off the presentation, and with that I'll turn it over to Mike

Heath, the Director of License Renewal for the Harris Plant.

MR. MIKE HEATH: Thank you, Brian.

With me today I've got Dave Corlett, who is the licensing and regulatory program supervisor at the Harris plant.

Matt Denny, equipment performance supervisor.

Back here in the corner, Chris Mallner, who is our lead mechanical engineer.

Next to him is Barry Schneidman, who is handling all of our implementation activities.

And Mike Fletcher, who wrote our application for us.

They may be answering questions as we move forward.

We are going to provide you some general information on the Harris plant, and we were asked to address four topics. The first of those is the water sources for the Harris plant, and Dave will be doing that.

Dave will also be discussing the open item on the feedwater regulating valves scoping.

I'll be discussing our electric manholes and the cable system associated with that.

And Matt will be discussing corrosion associated with the containment valve chambers.

So with that, I'll turn it over to Dave.

MR. CORLETT: Thank you, Mike.

Briefly, a little information on the Harris plant located approximately 20 miles south of Raleigh, North Carolina, originally licensed in 1986. It's a 900 megawatt, electric, three-loop Westinghouse PWR. The containment structure is a steel-lined reinforced concrete containment, and next I'll talk about the ultimate heat sink.

This is an overview of the main reservoir with the main band being right here, if you can follow the pointer, and the plant located approximately here. The auxiliary reservoir is another hold-up right here with a dam right there.

And the following is a closer in view of how we use that ultimate heat sink, and the red is the emergency service water. This is the emergency service water pump intake structure here that those pumps can take a suction either from the main reservoir or the auxiliary reservoir. The auxiliary reservoir is a higher elevation at approximately 250 feet, and the main reservoir approximately 220 feet of elevation.

The emergency service water pumps pump directly through the reactor auxiliary building in various heat exchangers and discharge to the auxiliary reservoir. So, for example, if the suction is aligned to the main reservoir, they would pump into the auxiliary reservoir raising that level. There's a small diversion dike right here which causes the discharged water to go through a longer flow path to return back to the auxiliary reservoir suction.

The cooling tower is shown here. You can see the plume there. In the dark blue is the normal service water pumps which use the cooling tower basin water and remove heat from the heat exchangers in the reactor auxiliary building and return that back to the cooling tower because the emergency service water pumps are not needed to run during normal operation.

And in the light blue are the circulating water flow path, which of course goes through the main conductor back to the cooling tower.

MEMBER ABDEL-KHALIK: What's the difference in the service water flow rate if it's pulling from either one of the two sources, given the difference in elevation, 30 foot to first?

MR. CORLETT: The flow rate is approximately the same. The emergency service water pumps are not significantly affected by --

MEMBER ABDEL-KHALIK: Thirty feet?

MR. CORLETT: The way that the auxiliary reservoir feeds the emergency service water pumps, it's a gravity flow from the screening structure here. Gravity flows, and it dumps into the same bay. So the reservoir water flows into that bay with the pump running. So it's not that much. There's some amount of feed of head difference, but it's not dramatic.

MEMBER CORRADINI: So just so I understand your arrows, so regardless of auxiliary or main reservoir, the lower right arrow is where the suction is taken for the emergency feedwater, emergency ESW?

MR. CORLETT: Yes. That's where the pumps are, and that's where the pay is where the pump is located. So regardless of whether the water is gravity flowing from the auxiliary reservoir into that bay or whether the valve is open for the main, that's where the pumps are located.

MEMBER MAYNARD: Which one is considered your safety related supply there? Is that both the main dam and the auxiliary or --

MR. CORLETT: The auxiliary.

MEMBER MAYNARD: Okay. For automatic line-up, does it automatically line up to the auxiliary reservoir then?

MR. CORLETT: Would normally line up to the auxiliary reservoir. Those suction valves do not automatically reposition, however.

MEMBER MAYNARD: Okay.

MR. CORLETT: It's just a normal line-up.

MEMBER MAYNARD: So it would be a manual action to switch to the main if you needed to for some reason there?

MR. CORLETT: Yes, it's manual action, manually operated valves.

With that, I'll move into the open item discussion on the feed regulating valves. The open item was related to the scoping, and the resolution is that the feed regulating valves, or feed reg. valves, are scoped for (a)(2).

I want to talk a little bit about where these are located. The feed reg. valves, feed reg. bypass valves, are in the non-safety related turbine building. It's an open turbine building, and as the feed lines progress through to the steam generators, they go through the reactor auxiliary building, and the check valve there that you see and the feedwater isolation valve in green are safety related in the safety related reactor auxiliary building before they go into the steam generators.

To start with an overview of the licensing basis discussion, and then I'll move into safety considerations after this slide, they are non-safety related, and the safety function of isolating feedwater is accomplished by the feedwater isolation valves in the reactor auxiliary building. The feed reg. valves are a backup to that, and our design is consistent with applicable NRC guidance.

MEMBER BANERJEE: I guess I'm missing something. Why is this an issue with the license renewal and not an ongoing issue?

MR. CORLETT: Mike can you help us?

MEMBER BANERJEE: I don't have any background. I didn't attend the subcommittee meeting.

MR. MIKE HEATH: Well, during the license renewal review process, we originally scoped these valves then as non-safety related, as (a)(2). They're equipment that supports the safety function.

The question was raised during the review process, well, if they support the safety function and, in fact, provide isolation, shouldn't they -- they had a safety intended function -- shouldn't they, in fact, be considered safety related.

From a license renewal standpoint and from our current licensing basis standpoint of view, they're not safety related. Therefore, they're not (a)(1). So we scoped them in as (a)(2), and that was the question that was raised.

MEMBER BANERJEE: So you're dealing with a specific issue which relates to the renewal or is it always a problem?

MR. MIKE HEATH: Well, it relates to the license renewal in the sense that our current licensing basis has these as non-safety related valves, where in the license renewal space, the question was, well, shouldn't they be considered to be safety related, and that was the issue that we had to resolve.

MEMBER BANERJEE: That's what you're telling us now.

MR. MIKE HEATH: Yes, and we're explaining why they're safety related, why they're not safety related, and why that's true.

(Laughter.)

VICE CHAIRMAN BONACA: They were always in scope, right?

MR. MIKE HEATH: They were always in scope.

VICE CHAIRMAN BONACA: Thank you.

Everything else is okay, like corrosion and all of these things related to that?

MR. MIKE HEATH: Yes.

MR. CORLETT: Well, I'll move on to the safety implications, which was a discussion requested from the subcommittee meeting as well. The feed reg. valves and feed reg. bypass valves do close on a main feedwater isolation signal. That signal is derived from a safety injection signal and the permissive P-14 high steam generator water level.

The valves also close upon a loss of the instrument air system and loss of DC power.

They are designed and maintained to high standards, and that's all I have prepared to say about the safety implications of these valves.

MEMBER BROWN: Well, they're non-safety related. So they just operate under the same auspices that isolation valves do.

MR. CORLETT: Yes.

MEMBER BROWN: If they don't -- I wasn't at the meeting. That was before my time. So it sounds like nobody cares. I mean, is that -- am I getting that wrong?

That's the wrong way to phrase it. It's just like they were never part of the current licensing basis relative to safety functions, and you're just reiterating and reaffirming that they are not for a specific reason. Is that --

MEMBER STETKAR: The issue, if I can jump in here a little bit, and back me up; the issue, Charlie, is that in the current licensing basis under steam line break inside the containment, Chapter 15, FSAR accident analyses, take credit for the feedwater reg. valves and the bypass valves as a backup isolation function because it's only one single safety related, active valve, single feedwater isolation valve.

MEMBER BROWN: Got you.

CHAIRMAN SHACK: To isolate the feedwater line. So if that fails, the actual licensing basis, current licensing basis for the plant takes credit for these non-safety related valves to perform that safety related feedwater isolation function, and there's a long history of why that particular function has been allowed in licensing space to be performed by non-safety related pieces of equipment, and that's the whole basis for this issue.

Because it's kind of a gray area for these particular valves. In the current licensing basis, they are non-safety related, but the Chapter 15 accident analyses and in the current licensing basis take credit for them to perform that safety related function.

MEMBER CORRADINI: So since you brought that up, the implication really is as a matter of periodic testing and QA for these valves going forward?

MEMBER STETKAR: And perhaps for people who are less familiar with this, either the applicant or perhaps the staff could explain in 30 seconds or a minute the functional differences between the (a)(1) requirements and the (a)(2) requirements, because that's the real crux of this issue.

MEMBER CORRADINI: Right.

MEMBER STETKAR: Is what type of performance monitoring requirements are assigned to these valves, if they were classified as safety related or required for a safety related function versus non-safety related pieces of equipment.

MEMBER BROWN: The reason I asked the question, they can answer that, but the flavor I got was this is the way it had always been, and now somebody was looking. Should we consider that in the status?

Is that the point?

MEMBER STETKAR: That's it.

MEMBER BROWN: All right. So a change in the licensing basis fundamentally.

MEMBER STETKAR: Right.

MEMBER BROWN: Okay.

MEMBER STETKAR: It's my understanding there is not necessarily the desire to formally reclassify them as safety related pieces of equipment. That hasn't been an issue. It's whether the performance monitoring programs for safety related equipment should be applied to these valves. So it's not necessarily reclassify -- it's a de facto reclassification, but not a formal, legal reclassification of the equipment.

Do we need a quick primer on the difference between (a)(1) and (a)(2)? I'd try it, but I'd mess it up.

MR. ROGERS: Yeah, hi. I'm Bill Rogers. I work in the Division of License Renewal, and I was involved with this issue, and as far as the process goes between (a)(1) and (a)(2), it really has to do with the way the surrounding environment is reviewed.

So as was stated, these valves were always in scope with the scope of license renewal, and they were in scope for (a)(2). When the technical staff reviewed these valves, there were some questions related to their reliance during an accident scenario, and that was more of a technical discussion.

The difference between the (a)(1) and (a)(2) categorization would be that if they were in scope for (a)(1), there would have to be a review of the surrounding non-safety related environment to see if that could impact the safety functions of an (a)(1) classified component.

When they're in scope for (a)(2), the review of the surrounding area is not required. So what it ultimately would result in is if they're in scope for (a)(2), there wouldn't be additional equipment brought into scope which could affect the performance of their safety function. That's the regulatory distinction between the two.

MEMBER CORRADINI: So just one clarification. So that means that if this was in scope for (a)(1), you'd have to look in the room and the surroundings about any sort of malfunction that would affect their safety function.

MR. ROGERS: That's correct. That's the total difference.

VICE CHAIRMAN BONACA: Capture additional equipment.

MEMBER CORRADINI: Right, right, and then, therefore, you bring in additional equipment that you have to worry about, yes.

MEMBER APOSTOLAKIS: Are (a)(1) and (a)(2) safety related?

PARTICIPANTS: No.

MEMBER APOSTOLAKIS: (a)(2) is not?

MEMBER STETKAR: (a)(2) is not.

MEMBER ABDEL-KHALIK: Have you ever had an LER related to the operability of either the feedwater reg. valves or the bypass valves?

VICE CHAIRMAN BONACA: Say that again. Sorry?

MEMBER ABDEL-KHALIK: I'm asking them if they --

VICE CHAIRMAN BONACA: I missed the question.

MEMBER ABDEL-KHALIK: -- licensee report related to the operability of either of these valves, either the reg. valves or the bypass valves.

MR. CORLETT: We haven't had any failure of the feed reg. valves to close. An LER, upon our unit trip, we would initiate an LER, and early in our operating years, dating back to 1987, we had unit trips related to the feedwater system. So I recall one time when we had lost instrument air system pressure, and the feed reg. valves closed, and the unit tripped, and that would have been a LER.

So we haven't had any LERs related to the failure to close. However, I don't have in front of me any feedwater related LERs, if that answers the question.

MEMBER ABDEL-KHALIK: I guess it has to do, since I'm not sure if you have access to that information -- is there any way you can find out and let us know as to the history of these valves?

MR. CORLETT: We looked at the history of the failure to close, and we have no history of that.

MEMBER ABDEL-KHALIK: Okay.

MR. CORLETT: So there may be history of them closing and causing a transient. I remember one of those.

VICE CHAIRMAN BONACA: It was told to close in that circumstances.

MR. CORLETT: Right.

VICE CHAIRMAN BONACA: It didn't close on its own. It was told by the instrument --

MR. CORLETT: Right, right. It was a reaction to the loss of instrument air. So we have looked at the history. We have no history of them failing to close on demand.

MEMBER ABDEL-KHALIK: But history of incidence of failing to fully close?

MR. CORLETT: From my memory, I'm not aware of any binding or failure to go full stroke. I don't believe that they are leak tested.

Mike, do you know of any leak testing requirements?

Are you talking about leak-by or failure to fully close?

MEMBER ABDEL-KHALIK: Both. I guess the check valves are lead tested, but I'm not sure if these two valves are leak tested.

MR. MIKE HEATH: I don't think we have an answer on that.

MR. CORLETT: I don't have information on the leak test. I'm not aware of any failures to fully close. We did replace the trim and actuator in 2000 with a more reliable design that was designed to make the valves more reliable from an operation -- from an erosion type standpoint, but not as a reaction to failure to close.

MEMBER MAYNARD: Do you have a manual isolation valve for your feed reg. valves?

MR. CORLETT: Yes.

MEMBER MAYNARD: I don't know about you, but at most Westinghouse plants, typically part of the procedure once you shut down or you trip anything that closes the feedwater reg. valves, that you then go out and manually shut that. I don't know what Shearon Harris does.

MR. CORLETT: For that function we have motor operator valves, but we also have manual valves in the turbine building.

MEMBER ABDEL-KHALIK: Thank you.

MR. CORLETT: That's all for the feed reg. valves discussion. I'll turn it over to Mike.

MR. MIKE HEATH: If there are no further questions on that open item, I'll discuss the electric manholes and discuss them in the context of the cabling system that runs through them. The reason this was asked to be addressed is associated with water that we get in those manholes.

We've had two failures of our 6.9 kV cabling system out in the yard over the last several years. The first occurred in 2002. The second occurred in 2006. In both of these cases the failure mechanism was water permeating into the insulation system ultimately resulting in failure.

In the failure in 2002, we could find no mechanical reason for that. There was no scarring. There was no damage caused by installation that we could find.

In the second case, we found that, in fact, when it was installed, we installed it with a minimum bend radius that exceeded the allowable, and we found that the failure occurred at the minimum bend radius. That was a failure of one phase of three. The other two phases were installed correctly and we tested those and those were good.

MEMBER STETKAR: Mike, if I could interrupt you just a second here, for the benefit of the members who were not at the subcommittee meeting, you kind of jumped into answering our concerns without the context for some of the other members.

The concern came up that Harris has, I think, if I remember, 180 manholes that provide access to underground cables, cable vaults, cable channels and things like that. There has been some evidence, a history of water accumulation in those manholes, and in some manholes to a depth where they found the cables submerged a few times.

So we raised a question about what has been the operating history relative to any actual failures of those cables, and we asked for a little bit more information about also the history of inspections of those manholes, any efforts to control water levels and things like that.

That's just a little general context for the other folks who weren't at the subcommittee meeting.

MEMBER BROWN: Are these safety related cable issues?

MEMBER STETKAR: They will discuss that, I think.

MEMBER BROWN: Oh, okay.

MR. MIKE HEATH: These two cables, the first went to an NCC at our intake structure and the second went to the make-up pump for the cooling tower, and neither were associated with safety related equipment.

However, all of our cables, all of our 6.9 kV cables were the same material. So any failure in that environment has implications for all the other cables.

Following the failure in 2002, we did a baseline inspection of all of our manholes. We pulled the lids off of them, took a look at them, and that was as much to look to see if we had water in the manholes as to see what kind of structure damage might have occurred.

We then established a 90-day frequency for pumping out the manholes with the exception of one manhole that has a 45-day frequency, and that obviously is a shorter frequency because we have water problems in that particular manhole.

We do trend that. We do, in fact, find some occasions when we have water over the cables in those manholes.

MEMBER STETKAR: Mike, I had some notes from the subcommittee meeting, and I think during the subcommittee meeting we're told that manholes that contain energized cables were inspected and, if necessary pumped down every 45 days, and manholes that contain normally de-energized cables were inspected very 90 days.

This slide seems to indicate something different.

MR. MIKE HEATH: We do, in fact, pump down manholes every 90 days regardless of whether they have energized cables in them or not.

MEMBER STETKAR: So the normal inspection frequency is once every 90 days?

MR. MIKE HEATH: Every 90 days.

MEMBER STETKAR: With the exception of

this one.

MR. MIKE HEATH: That's a pump-down frequency. With the exception of that one. This one is every 45 days.

MEMBER STETKAR: When you say "pump-down frequency," does that mean also the frequencies which people pull the manhole cover off and look down in the hole?

MR. MIKE HEATH: No.

MEMBER STETKAR: How frequently do people do that?

MR. MIKE HEATH: That is a nine-year frequency. We actually do the inspection. Now, we check water level before we pump it out, but we don't pull off the manhole cover.

MEMBER STETKAR: The water level, do you have lever indicators?

MR. MIKE HEATH: I think they use a dip stick.

MEMBER STETKAR: Huh?

MR. MIKE HEATH: They use a dip stick.

MEMBER STETKAR: A dip stick? Okay.

MR. MIKE HEATH: Yeah. What we're trying to establish now is this program is relatively new, and what we're trying to establish as we go into this program is where the cables are in the manholes and whether or not water gets up over the cables and adjust our frequency based on that information.

As I was saying, we do know that we do have some cases where water gets up over our cables

MEMBER ABDEL-KHALIK: Now, this trending that's being done is based on this 90-day frequency?

MR. MIKE HEATH: It's based on the 90-day frequency.

CHAIRMAN SHACK: But your implication is that you will change that frequency if necessary, if you find water over the cables?

MR. MIKE HEATH: Yes. And what we have found is that we've got some of the manholes where we find inches of water in there each time. So we're not going to continue to do those on a 90-day frequency.

We have this one manhole in particular that we're doing on a 45-day frequency. The last two times we've checked it we've had more than six feet of water in there. Prior to that, we were getting about two or three feet of water in there. So we're going to be looking at increasing the frequency on that while we decrease the frequency on some of the others.

This picture gives you an idea of what

these manholes look like. They're essentially just large cable vaults, concrete vaults. The cable would come in one side, exit another, often changing directions or changing elevations as they go through.

The openings you see at both sides there are actually we have a set of conduit that come in there. For this particular manhole and for most of our manholes, those conduits are not sealed. We do, in fact, have at least one manhole in which we have sealed those conduits, but typically the typical arrangement is not to seal them.

MEMBER BROWN: So they communicate water from one manhole to the other through those conduits?

MR. MIKE HEATH: They could or you could have water getting into the conduits in between the manholes.

MEMBER BROWN: And then it would go either way?

MR. MIKE HEATH: Well, we would assume it goes either way. You may, in fact, have a low spot there where it accumulates.

MEMBER RYAN: Is the source of the water all surface water running down or is there any groundwater coming up?

MR. MIKE HEATH: It could be either.

MEMBER RYAN: Or both?

MR. MIKE HEATH: It could be either. We do see a direct correlation between rain events and water in the manholes.

MEMBER RYAN: The surface going down might be the driver.

MR. MIKE HEATH: We think that is the driver.

MEMBER MAYNARD: I was going to ask about that because just putting it on a number of 45 days or 90 days may not be the right answer. You may have to consider what's causing it, and it may have to be pumped down after a certain amount of rain or after whatever other event might be causing it there. So it may not be just so many days.

MR. MIKE HEATH: A rain event may be implicated. We will be looking as we go forward if this is a problem and continues to be a problem putting in putting systems. You know, whatever is easiest for us to do, we're going to do it. The idea is, of course, you really don't want to have a wet-dry-wet-dry situation with these cables. That's probably the worst possible scenario.

A wet scenario is bad. Wet-dry-wet-dry is probably worse, and dry is what you're looking for.

MEMBER RYAN: Have you ever tried that correlation with rain events or rainfall rates?

MR. MIKE HEATH: We have not. We're too early into it.

MEMBER RYAN: Okay.

MR. MIKE HEATH: And essentially since we started this we've been in drought until recently.

(Laughter.)

MR. MIKE HEATH: Fortunately we've had a lot of rain events. The cables don't appreciate that, but everybody else does.

As a result of these failures and looking at how we do, corporate-wide basis, how we do cable testing, we went out and we looked at all of the different testing capabilities out there, and we decided from a corporate standpoint you have shielded medium voltage weighted cables that we test using the high voltage, very low frequency, tan delta testing.

We've done significant testing at our Brunswick plant, and we've done some testing at Harris, and we find it to be very effective. We do believe it gives very good answers. It shows us where we have degraded cables but not failed cables. It gives us time. In some cases we just monitor those more frequently. In other cases we have replacement work tickets out.

For the Harris plant, we have a total of 17 cables that we're looking at. Those are safety, non-safety, and they may just be going to out-buildings. We've currently tested four cables, one of the normal service water pumps, one of the emergency service water pumps, one of the circulating water pumps, and those have all tested okay.

We did a test on one of our maintenance shop feeders. We tested it because we were having ground faults associated with it and found that it wasn't okay. That cable is still in service. It's still in operation. We have a work ticket out there to replace it at the earliest possible moment, and once we pull it out, we'll take a look at it and see what the issue is there.

The bottom line for us is that we have had cable failures. We've gone out and taken a look at all of our manholes. We have an inspection frequency for the manholes, a pump-down frequency for them, and a testing program for all of our cables that are important to us in the system.

More questions?

MEMBER STETKAR: I think it came up in a subcommittee meeting. Do you have, do you know or have an estimate you can share with us about the number? Is 180 the correct number for the --

MR. MIKE HEATH: For manholes?

MEMBER STETKAR: For manholes.

MR. MIKE HEATH: The manholes that we actually care about are about 50.

MEMBER STETKAR: Okay.

MR. MIKE HEATH: It's not 180. I'm not sure where that 180 came from.

MEMBER STETKAR: I had it written down in notes. So it could have been an anecdotal comment during the subcommittee meeting. So let's say it's 50 if the population is 50.

Do you have any estimate from that population how many contain safety related cables?

MR. MIKE HEATH: Yes. Actually I've got the number in my briefcase. It's ten or 12, something on that order.

MEMBER STETKAR: You said safety related. Insulation, safety and non-safety cables have the same insulation?

MR. MIKE HEATH: Same insulation. It's an Anaconda unit shield.

Yes, sir?

MEMBER MAYNARD: Do I understand you

correctly? A while ago you said you linked the one vault that typically had two or three feet but the last few times you've been finding six to eight feet of water or something like that?

MR. MIKE HEATH: Yes.

MEMBER MAYNARD: Does that get entered into your corrective action? Do you start looking for why that's occurring or do you know why that's changed?

MR. MIKE HEATH: We don't. There were large rain events in each of those cases. The system engineer maintains a spreadsheet of all the work orders. So he goes and collects the work orders, takes it in the spreadsheet and analyzes that, and then he's going to be making adjustments to his frequencies based on that.

MEMBER MAYNARD: Okay. So that can be attributed to the recent rain and --

MR. MIKE HEATH: Yes, sir. He notes that on there, you know. If there has been a rain event, he is noting it only there. Where he knows where the level of the cable is, he's noting that the water is over it or under it. So he's keeping up with all of those things.

Yes, sir.

MEMBER BROWN: I remember you said there were ten or 12 safety cables in this.

MR. MIKE HEATH: There were a total of 17 cables.

MEMBER BROWN: Okay, and it was some number of relative -- I mean, I think John asked about how many of those were safety related or whatever, and I thought you gave a number of some kind.

MR. MIKE HEATH: I did not. There's a total of 50 manholes, but in the license renewal aging management program for this, there are four pumps that are in that system. Two other safety related feeders are to the emergency diesel generators. We also look at those manholes, and we're looking at those cables.

Essentially, we look at all of our 6.9 kV cables in the yard. We're looking at all of manholes that those go through, and we're looking and we're testing all of those cables whether safe related or non-safety related.

MEMBER BROWN: Okay. I guess what I was looking for, and I didn't phrase it right, if there are safety related cables in these manholes that are getting filled up, is it a potential for a manhole filling to compromise the separation or independence of some cables that are running to some other safety related, where you need to maintain an independence such that, for instance, you mentioned communication from one manhole to some other cluster of manholes, and then you said stuff comes in and out.

Do they merge? Do they not merge? Do you always --

MR. MIKE HEATH: My understanding --

MEMBER BROWN: -- maintain a separate train of manholes like you have a separate train of controls or what?

MR. MIKE HEATH: My understanding is --

MEMBER BROWN: My point is could one flooding or two floodings take out the cables?

MR. MIKE HEATH: But you'll have like an alpha train and a bravo train of manholes.

MEMBER BROWN: You maintain separation of trains of manholes.

MR. MIKE HEATH: Yes. However, you would expect the same environment in both trains.

MEMBER BROWN: But you didn't see the same amount of water in all levels.

MR. MIKE HEATH: That's true. That's okay.

MEMBER BROWN: So my point being, my question -- I think you've answered it -- is that for safety related cables you maintain a separation manhole-wise as well as -- I mean, it gives you physical, but there's no communication between those sets of manholes, and you don't mix cables.

MR. MIKE HEATH: We don't mix cables.

MEMBER BROWN: Or allow communication from manhole train to manhole train?

MR. MIKE HEATH: No.

MEMBER BROWN: Okay, all right. Thank you.

MR. MIKE HEATH: Other questions on this?

Okay. Matt will discuss our valve chambers.

MR. DENNY: Thanks.

I'm Matt Denny. I'm one of the engineer supervisors at the Harris plant, and during the subcommittee discussion there was a lot of discussion about the external and some internal corrosion that we've detected on the valve chambers, and we were asked to come back and provide some follow-up.

Was that a summary?

MEMBER STETKAR: Indeed it is, and for the benefit of the people who were not at the subcommittee meeting, could you just briefly explain what the valve chambers are and why the issue came up?

MR. DENNY: I'd love to do that. That's actually my first two slides.

MEMBER STETKAR: Oh, okay. Good.

MR. DENNY: I started off with that.

PARTICIPANT: What a team.

MEMBER STETKAR: I'm a good straight man.

MR. DENNY: All right. On the monitors you'll see a picture of a typical containment valve chamber. This one happens to be for a containment spray. Visually you're seeing approximately one-third of the valve chamber. The other two-thirds is imbedded into the concrete, and the only way to access these valve chambers is from the access hatch on the top of them.

During power operations, they are normally closed. It's considered a containment environment. So it's closed.

MEMBER STETKAR: It's important for members who aren't really familiar with this particular -- it's kind of a feature of a few plants around. If you go back to -- well, this is good, too, right?

MR. DENNY: Right.

MEMBER STETKAR: That thing that you saw, although it's in the auxiliary building, indeed, is the containment.

MR. DENNY: Correct.

MEMBER STETKAR: That's considered the containment boundary.

MEMBER CORRADINI: The atmospheric pressure or the atmospheric containment goes to that steel liner.

MEMBER STETKAR: That is the containment pressure boundary. It is physically inside the auxiliary building.

MEMBER CORRADINI: It kind of bulges out a bit.

MEMBER STETKAR: It bulges out.

MEMBER BROWN: So if you look, that is the auxiliary building on the left-hand side of that?

MR. DENNY: Yes.

MEMBER BROWN: What looks like the structure, concrete, poured concrete, whatever in the heck it is?

MR. DENNY: Let me explain this a little bit and I think I'll answer a lot of these questions. On top of the picture I'm showing is the containment sump. So this is the basement of containment. And this is basically a liner imbedded in the concrete substructure. This is in the reactor aux. building, and this is open to containment.

This is a penetration. It is welded seal or seal welded. So there's no communication with the containment atmosphere. Okay? So it's basically its own atmosphere inside. Once we open it and close it during an outage, it's its own atmosphere.

The process pipe, either RHR or containment spray, is internal to the valve chamber taking the suction off of the containment sump.

The elevation on this, normal ground elevation is --

MEMBER BROWN: Is that filled with water?

MR. DENNY: No.

MEMBER STETKAR: Hopefully not.

(Laughter.)

MEMBER BROWN: The suction for the --

MR. DENNY: Containment sump.

MEMBER BROWN: Okay. Where the reactor is located.

MR. DENNY: Right. The reactor is up top.

MEMBER BROWN: Okay, all right.

MR. DENNY: The normal ground elevation is 261. The elevation of the containment sump is 216. The actual elevation of the containment valve chamber is 190.

MEMBER BROWN: So the auxiliary building is not part of the containment.

MR. DENNY: That's correct.

MEMBER BROWN: Okay, okay. I thought somebody said it was though.

MR. DENNY: No, the reactor aux. building is not part of the containment.

MEMBER STETKAR: That thing bulges into the aux. building and that --

MEMBER BROWN: That boundary in the chamber. Okay. All right.

MR. DENNY: If you're on the 190 elevation of the reactor aux. building, this is the concrete wall that you're going to see at that elevation, and you'll see the structure sticking out of there.

MEMBER BROWN: Okay.

MEMBER STETKAR: A photographs shows that.

MR. DENNY: Yeah, I can go back and show you. So right now we're standing in the reactor aux. building, 190 elevation, looking at the wall, which happens to be not quite underneath containment, but it's --

MEMBER BROWN: Okay. I've got it now.

MR. DENNY: All right. What we have is talking about the groundwater and how it comes into the reactor aux. building. Since the early '80s we've detected water coming into the reactor aux. building. We tried through the late '80s, early '90s to pressure grout, to seal or somehow prevent the water from getting in there.

In 1996 time frame, we implemented the water in-leakage plan where we've started diverting the water to collect it and put it where we can remove it correctly out of the building.

MEMBER CORRADINI: And it's coming in from seepage from the outside, I assume.

MR. DENNY: Correct. It's seeping through the concrete, the seams of the concrete and coming in.

MEMBER CORRADINI: Like a basement.

MR. DENNY: Correct.

MEMBER CORRADINI: Somebody's basement.

MR. DENNY: And we're continuing to monitor where it's coming in. We've made locations and we monitor where it's coming in.

Okay. So what I'm going to go on to now is the external, the external surfaces. So now we're talking about the reactor aux. building side of this.

MEMBER ABDEL-KHALIK: But before you do that.

MR. DENNY: Yes.

MEMBER ABDEL-KHALIK: Internal surfaces, do any of the valves have a history of leakage?

MR. DENNY: Internal surfaces?

MEMBER ABDEL-KHALIK: Right.

MR. DENNY: I was talking to the system engineer, the coding system engineer, who happens to be the structure system engineer also. So it's kind of a two for one deal. He's the one that basically goes into the internals of these and does the inspections, and he says he's never gone in there and seen leakage or seen it wet on the internals.

So to answer that question, they might have minor leakage of the valve packing. I wouldn't expect it because it only has the water head in the containment sump, but there hasn't been any.

MEMBER ABDEL-KHALIK: Okay.

MR. DENNY: What?

MEMBER STETKAR: There's not normally water in the containment sump.

MR. DENNY: Yeah, we maintain the water level in the containment sump.

MR. CORLETT: In the pipe.

MR. DENNY: In the pipe. I'm sorry, yeah.

MR. CORLETT: So there's water in the pipe but not in the sump.

MEMBER BROWN: One clarification for me. It's dry.

MR. DENNY: Correct.

MEMBER BROWN: If water accumulates in the sump, you pump it out. Is it recirc? Is that the purpose? What's the purpose of the containment isolation?

MEMBER STETKAR: These are the safety related containment sump spray RHR re-spray --

MEMBER BROWN: Recirculation back and spray down. Okay. I just wanted to know where it was system-wise.

MR. DENNY: And, again, you wouldn't get the water. When the water is in the sump here, this is a sealed penetration. So it goes internal to the process, which is internal to the containment valve chambers.

MEMBER BROWN: You just lost me. If it's sealed, how do you take a suction on it?

MR. DENNY: This is open, open up top, sealed to the liner.

MEMBER BROWN: Oh, okay. I've got you.

MEMBER MAYNARD: The chamber is basically an encapsulation for the pipe and the valves.

MEMBER BLEY: Charlie, the dashed line is the pipe.

MR. DENNY: The pipe, and there's a penetration on top which seals the internal --

MEMBER BROWN: Okay. I've got it. All right.

MR. DENNY: Okay?

MEMBER BROWN: I never perceived dashed lines as being a pipe.

MEMBER STETKAR: Think of this as a funny looking containment penetration.

MEMBER BROWN: I've never seen a pipe being shown as a dashed line as opposed to a pipe. So it's a pipe within the chamber.

MR. DENNY: That's correct.

MEMBER BROWN: Okay. Boy, that really helps a lot.

MR. DENNY: All right. Moving on, we talked about the structures from the external. Our engineering staff looks at them. Approximately every six years these surfaces are looked at. This is considered part of containment. It is part of the IWE program, which is looked at approximately every two outages. It's every three and a third year, which turns out every two outages.

Well, when we do find evidence of coatings damage, which is what we're going to see on an external surface, it is removed. Examination is performed to determine the extent on the base metal, which would be the valve chambers, and recoated.

To date we haven't found any metal loss. You know, we find corrosion, surface corrosion, no appreciable metal loss.

Going on to the internal, since 2000 we've been doing some internal inspections. QC goes in. Part of the IWE program, we do a visual inspection. We've seen some blistering approximately a 16th inch in diameter, very small. We've attributed it to condensation being the concrete is imbedded -- I mean, I'm sorry, the steel is imbedded in concrete with its own atmosphere, and some degraded coatings to go with that is what's causing the blister on the coatings.

We remove the coating to perform UT thickness measurements; haven't seen anything below nominal thickness yet, which is above a half inch thick in addition. So this is pretty thick itself. In all cases, we always replace the coatings.

Since 2004 we haven't seen further blistering on the interior surfaces. We did have to repair some damage to the coatings that occurred when we were gaining access to the inside surfaces to one of our valve chambers. So that was repaired and some new coatings were put on.

In addition, I talked about QC doing the internal inspections every two outages.

VICE CHAIRMAN BONACA: The program foresees changing the frequency of inspection, that isn't what you find? I would expect that you have some of that element in it.

MR. DENNY: That's correct, and being in the IWE program, it's an ASME Section 11 type program. When you find degradation that you have to evaluate, you have to increase the frequency or put it into another category which would require like an augmented category, they call it, which would require a different type frequency of inspections.

VICE CHAIRMAN BONACA: And currently frequency of inspection is every four years?

MR. DENNY: Right. If it went into the augmented category, it would be every outage. We would have to be doing UT on it, but sine we're not finding the degradation, it hasn't made it there yet.

MEMBER ARMIJO: How many of these chambers do you have?

MR. DENNY: There are four of them.

MEMBER ARMIJO: Four of them?

MR. DENNY: Two for RHR and two for containment spray.

MEMBER ARMIJO: And all of them get the same level of inspection?

MR. DENNY: That's correct.

MEMBER BLEY: Did you find the corrosion in all of them?

MR. DENNY: There has been corrosion found in all of them. It's like one year we find it in one. The next year we find it in another. That's why I didn't get into all of that, because you go to alpha containment spray and bravo RHR. It gets kind of confusing, but there has been corrosion found in all of them.

I say corrosion at surface. What we're really finding is the blistering on the coatings.

MEMBER ABDEL-KHALIK: Are the manholes in these chambers part of the containment leak test?

MR. DENNY: Yes, they are. That's why we don't open them on line, because we do an LRT on them when we start up, and then we leave it closed.

MEMBER CORRADINI: And this is just background since I can't remember. Do you an LRT every ten years?

MR. DENNY: No, local leak rate tests.

We're still Option -- I believe it's Option A, which is review at every outage.

MEMBER CORRADINI: Some sort of leak rate test?

MR. DENNY: We haven't gone to the performance based leak rate test, but we perform that every outage.

MEMBER CORRADINI: Thank you.

VICE CHAIRMAN BONACA: Would you expect any corrosion between the concrete and the metal? I mean they're on the outside surface of it?

MR. DENNY: The exterior surfaces were all coated, and they were imbedded in concrete, and the corrosion rates of the steel in concrete is much lower. So while we do expect it, it is a lot. I would expect it to be a much lower rate than I see visually.

MEMBER BLEY: You don't have any way to look at that.

MR. DENNY: No, the only way we could, if we were suspecting it, we could be doing UT on the ID to see what the OD is showing. If we were suspecting that, that's probably what we would go to.

CHAIRMAN SHACK: But you have full access to almost the whole surface in there.

MR. DENNY: That's correct.

PARTICIPANT: But in a leak you wouldn't expect it.

MR. DENNY: Not with the pipe going up.

CHAIRMAN SHACK: It would surprise me, yes.

VICE CHAIRMAN BONACA: But at times you get surprised.

MR. DENNY: So our conclusion, although we do have -- I'm sorry? -- although we do have water coming in the RAB, we tried to mitigate it with early grouting and pressure sealant, pressure grouting and sealing what's on the grout. We channeled it to where we can control it, and we do routine inspections, which is maintaining the integrity of the valve chambers.

MEMBER CORRADINI: I guess maybe this was asked and I just didn't hear your answer. So the moisture inside the blistering, I assume moisture grew in blistering on the inside of your valve chamber. The source of that is this humidity build-up from leakage?

MR. DENNY: Yeah, it's kind of --

MEMBER CORRADINI: I shouldn't say leakage, but from communication from the rest of containment.

MR. DENNY: Well, we're attributing it to the cold concrete. When we start up, it's still warm in there. So we have a cold and you put a steel structure in the ground and you get cold condensation with some initial contaminants underneath the coatings, which is causing the blistering.

CHAIRMAN SHACK: But there's no communication to the atmosphere, right? This thing is sealed on --

MR. DENNY: Its own atmosphere, that's correct.

CHAIRMAN SHACK: Yeah, it's just a big--

MEMBER CORRADINI: It's sealed on both sides.

MR. DENNY: It's the reactor aux. building atmosphere until we start up. Then it's its own atmosphere.

MEMBER BROWN: Well, that's when you seal it.

MR. DENNY: Correct.

MEMBER BROWN: So it is open. You're exchanging air at least in that point, and if it's warm and humid, then it's trapped in there, and then when you start up it's cold. It condenses.

MR. DENNY: That's correct.

Questions on that topic?

MR. MIKE HEATH: Well, that concludes our presentations. Any other questions concerning Harris license renewal that we can answer for you?

(No response.)

MR. MIKE HEATH: Thank you very much.

MEMBER STETKAR: Thanks very much.

(Pause in proceedings.)

MEMBER STETKAR: Now I guess we'll hear from the staff about resolution of the open items. There were two confirmatory items that we didn't go over in the presentation from the applicant because of time considerations. We wanted to go over and make sure we had enough time to discuss all of the technical issues both on the open SER item and the issues that came up during the subcommittee meeting. So we didn't discuss the two confirmatory items, but they are more or less administratively taken care of.

So with that, Maurice, it's yours.

MR. MAURICE HEATH: Thank you.

And good morning. Again, my name is Maurice Heath, and I'm the project manager for Shearon Harris license renewal application.

Today we have, as stated earlier, we have our staff in the audience and also Mr. Cardell Julian is on the phone from Region 2, who was our lead inspector, and he's there to answer any questions as well.

All right. What we're going to do now, let me just step through what we're going to cover. We're going to have a brief overview. We're going to discuss the resolution of open item 2.2, as well as the resolutions for confirmatory item 3.4-1 and 4.3.

As the applicant mentioned, I will just briefly go through this. LRA was submitted November 2006 as a single unit, Westinghouse three-loop PWR, 2900 megawatt thermal and 900 megawatt electric, and the operating license expires October 2026, and the plant is 20 miles southwest of Raleigh, North Carolina.

At the subcommittee meeting, we presented the results from the safety evaluation report with open items that was issued in March of 2008, and it contained one open item and two confirmatory items.

During our process, we had 346 audit questions asked, 75 RAIs issued, and the end result, we ended up with 35 commitments in the SER with open items.

Now, since the subcommittee meeting, we

have issued our final SER in August 2008, and we have the resolution of open item 2.2 and the two confirmatory items, and we also have two additional commitments that were added as a result, and those two commitments came from the resolution of the confirmatory items.

One open item came from Section 2.2, plant level scoping. What I want to do is kind of give you a little background information and then discuss the resolution of that. So the Harris FSAR credits that feed regulating and bypass valves for redundant isolation function following main steam line break.

However, the feedwater isolation is not listed as a function of the feedwater system in the license renewal application, and the LRA states that the feedwater regulating and bypass valves are non-safety related per the current licensing basis and are in scope per 54.4(a)(2).

In addressing this open item, staff identified the follow. Fifty-four, four (a)(1) specifies that the following safety related SSCs should be included in scope if they meet 54.4(a)(1)(i), (ii) or (iii). The criterion 54.4(a)(1) agrees with the definition of safety related specified in 50.2.

Now, if the applicant's definition of safety related differs from 54.4(a)(1), the methodology the applicant used was based off NEI 95-10, and that states that the applicant should use a criterion 54.4(a)(1) to determine that the SSC is to be included in scope.

And if the applicant has CLB documentation indicating that the NRC has approved specific SSCs to be classified as safety related, which would otherwise meet the applicant's definition of safety related for the 54.4(a)(1) criteria, that these structures, systems, and components are not identified to be within scope in accordance with 54.4(a)(1).

Now, if these SSCs are classified as non-safety related in accordance with the CLB but have potential to affect the functions described in 54.4(a), they should be included in the scope in accordance with 54.4(a)(2), non-safety related affecting safety related.

Now, the resolution of this one item in LR Amendment 8, that was dated May 30th, 2008. The applicant revised Section 2.3.4.6 to add feedwater isolation as an intended function in the feedwater system.

The applicant also has documentation, CLB documentation indicating that NRC has approved classifying these valves as non-safety related.

So LR Amendment 8, also the applicant took exception to the scoping methodology in NEI 95-10 and used the current licensing basis and the scoping definition in 54.4 to determine these valves are in scope per 54.4(a)(2).

So the staff has come to the conclusion that this position is consistent with the current licensing basis and the scoping definition in 54.4.

MEMBER MAYNARD: I'm kind of wondering why this came up with Shearon Harris. What's unique about it? Because this configuration isn't, I don't think, all that unusual for other Westinghouse plants.

MR. MAURICE HEATH: Correct.

MEMBER MAYNARD: So did it come up on other plants, too, and get resolved somehow? What's unique about Shearon Harris, I guess?

MR. MAURICE HEATH: Well, other applications, some applicants have already put it in scope for (a)(1), but Donnie, do you want to?

MR. HARRISON: This is Donnie Harrison, Branch Chief for balance of plant, at least during this review.

(Laughter.)

PARTICIPANT: You're in transition.

MR. HARRISON: That's right. That's right.

But Maurice has got it right. In the past we've asked questions of licensees on this area, and the licensee has put it in scope for (a)(1) and treated it as (a)(1), and this licensee actually tried to address the RAIs, push back and address the RAIs directly and, again, took exception to the NEI guidance that we were reading as driving you to put it into (a)(1), and they reverted back to the actual rule and the rule language to establish the position.

MEMBER STETKAR: So this is the first one? You know, having been on the Committee for only a year and only seen a few of these, is this the first instance where the applicant has, indeed, taken exception and pushed?

MR. HARRISON: Yes.

MEMBER STETKAR: I want to make sure the rest of the Committee is aware of that because we're going to set a precedent here.

MEMBER BROWN: So the rest of the license renewals that come in are going to do the same thing, say, push back on it?

MEMBER MAYNARD: They may or may not.

MEMBER STETKAR: They may or may not, but just be aware of that fact this is (pause) --

MR. HOLIAN: Yes, this is Brian Holian.

Just to add to that, I mean, the Committee who was here last month, you know, faced an issue with station blackout scoping in the switchyard for Wolf Creek. It's not exactly similar to that, but I guess from a license renewal perspective, you're on the edges of how a plant is either scoping an item in in their CLB or not, and in one reality this might have been able to be resolved by either a legal interpretation or, you know, even prior to the subcommittee.

However, it wasn't. One perspective, it's refreshing that we look at the rule on each plant and a technical reviewer and review both the license renewal application and, of course, the CLB application.

So I guess from my perspective, I mean, it's refreshing that the questions still come up and that we're looking at it with new eyes, and you are right. We want a certain percent or certain degree of uniformity, but that's the positive aspect as I'm looking back on it. I mean, we're still questioning the rule as written and how we're implementing it.

VICE CHAIRMAN BONACA: And the question I have is that you look back to see what difference it makes in scope. What I mean is that if you interpret these components as being sensitive like that, you would include then additional surrounding components to explain your caused failure of this. And you have seen it for previous plants.

I mean, is it a significant scope change?

MR. HARRISON: Yeah, but I would say it this way. If you put it in scope for (a)(1) and then bring into scope additional components that are non-safety related, you're actually doing something that's more conservative in that mode.

So this was, again, reverting back to actually what the ruling said and the positions in the Statement of Considerations for the rule. So we have looked back at like feedwater isolation function at other plants, and there's a lot of different ways to get feedwater isolation, and some are safety related; some are non-safety related. It's a very open-ended solution.

So the bottom line is we've looked back. We haven't gone back to licensees and said, you know, take those things out of scope. You've done something that's actually more concerning what the rule requires.

VICE CHAIRMAN BONACA: I didn't mean that. I'm just trying to understand what differences it makes.

MR. HARRISON: The significance would be how much additional equipment and the practicality of bringing additional equipment into scope. If you're in a building that's got a number of non-safety related components around the isolation valve, that could be problematic for some plants, but that's how we would look at it.

MEMBER STETKAR: I think also one of the concerns here is that -- correct me if I'm wrong -- Shearon Harris turbine building is an open --

MR. HARRISON: Yes.

MEMBER STETKAR: -- open turbine building. So there could be additional concerns about environment and how do you control the environment around humidity.

MR. HARRISON: And that I would --

MEMBER STETKAR: Which might not be faced by another virtually identical, you know, system design, but inside an enclosed turbine building and in an environment that could be more easily controlled. I mean, you're not just worrying about proximity to other pumps and pipes and valves.

MEMBER MAYNARD: Every one of these plants has unique differences.

MEMBER STETKAR: That's right.

MR. HARRISON: And I guess from the staff perspective, when we see those unique differences, that's where we start to focus in on our review to make sure we are at least establishing a good regulatory basis for it.

VICE CHAIRMAN BONACA: Thank you.

MR. MAURICE HEATH: I'm going to move on to first confirmatory item, which is 3.4-1, and this came about because the applicant credits managing changes in materials and cracking of elastomeric and other plastic components with the external surface monitoring program.

However, in the GALL aging management program, it recommends visual inspections for carbon steel components, but does not address elastomeric and other plastic components. So the way that we resolved this was the applicant will use the preventive maintenance program which will periodically replace these components based on site and industry operating experience, equipment history, and vendor recommendations.

MEMBER BROWN: What's GALL? Is that an acronym or is that --

MR. MAURICE HEATH: Generic aging lessons learned.

MEMBER POWER: It's the Bible for this stuff.

MEMBER BROWN: The what?

MEMBER POWER: The Bible.

MEMBER BROWN: Why in the world -- elastomeric stuff degrades, and I guess I'm having a hard -- not just a hard time, but just I have a hard time imagining that you would look at the steel components and it shrinks, particularly if it's in a humid temperature varying environment. So --

MEMBER POWER: The basic philosophy of the license renewal that replaceable components are replaced and those that are not get inspected.

MEMBER BROWN: So they replace the elastomeric?

MEMBER POWER: It's got the principle, the number one principle in the GALL report.

MEMBER BROWN: Okay. Thank you.

MR. MEDOFF: Let me clear this up for you. This is Jim Medoff of the staff.

The issue was that the applicant's

external surfaces monitoring program was enhanced to include these types of components, but if you look at the GALL program, it doesn't cover elastomers.

Now, if you look at the AMRs for elastomers in the GALL report, it credits visual examinations for changes in properties, and for cracking we had a couple of issues with this. You can't use a visual examination to detect a change in a material property. Usually you have to analyze for it.

The second issue was if you were going to credit a visual for cracking, you would certainly have to define what type of visual examination you were using. For instance, if you look at the ASME Section 11 IWA criteria, it only credits VT-1 type of examinations for cracking, and for polymers it's not even -- we're not even sure a visual would be capable of doing this. An example would be if you have been riding your bike and you have a plastic water bottle, sometimes it leaks out and you notice your pants are wet, but you can see the water. You can't see the crack.

So the issue with the polymers is that GALL may not currently be quite adequate, and we had to raise the issue of how an external surfaces monitoring the program could be used to manage the aging effects for the elastomers and the polymetric components.

What Harris has done is they decided to, rather than include them in their AMRs, that they're going to periodically replace them, and under the rule if you have components that are periodically replaced on a specified frequency, then you can take them out of the aging management reviews.

MEMBER BROWN: Okay. Thank you.

MR. HOLIAN: Just to summarize -- Brian Holian again -- next month I think we have a license renewal update for the committee on where we are with GALL and how we're updating aspects of that.

MEMBER ABDEL-KHALIK: Now, what is the current practice at the plant with regard to these components? Are they replaced when they fail or is there currently, you know, a periodic replacement program?

MR. MAURICE HEATH: For currently, I would actually pass the applicant for that, what they currently do with these items, these components.

MR. SCHNEIDMAN: Hi. I am Barry Schneidman.

I looked at the PM program basically sets up periodic replacements for these on a scheduled interval, and that's based on that they saw some surface cracking on some of the hoses and decided to select -- there was no substantial damage. It's just some surface crack, and so they decided to use that as a frequency for replacement.

MR. MAURICE HEATH: Our second confirmatory item comes from Section 4.3 of my time limited aging analysis section, and this one came based on the applicant used a WESTEMS special purpose computer code in calculating stresses from transients. The code is benchmarked for pressure, thermal moments and thermal transients. Excuse me.

A 60-year fatigue re-analysis was completed for all 6260 components with two components having a 60-year CUFen greater than one. Now, the confirmatory item was issued to insure consistency between the re-analysis and the original design specification.

Now, for the resolution, the applicant commits to update the design specification to reflect the revised design basis operating transients, which was commitment 37.

Also, the FSAR supplement was updated to reflect that Harris crediting of the fatigue monitoring program to manage aging for reactor coolant pressure boundary components according to 54.21(c)(1)(iii).

CHAIRMAN SHACK: Okay. So this comes from a different vendor. So there's no problem with a 1(d) virtual surface calculation.

MR. MAURICE HEATH: Right, correct. This is the Westinghouse version.

MEMBER ARMIJO: Now, what do you do with those two components that have a 60-year usage factor greater than one? Might you resolve it by changing the design basis transience or --

MR. MAURICE HEATH: No, we resolve it by monitoring those components, and that's what the aging fatigue monitoring program does. They're going to monitor it for the 60-year period.

MEMBER ARMIJO: Okay.

MR. MAURICE HEATH: And with that, on the basis of its review, the staff determined that the requirements for 10 CFR 5429(a) have to be met.

VICE CHAIRMAN BONACA: There were a number of inspections made, right? Were a number of inspections made?

MR. MAURICE HEATH: Inspections for?

VICE CHAIRMAN BONACA: Well, site

inspections for scoping that you would normally have?

MR. MAURICE HEATH: Oh, we had a number of inspections, on-site inspections from audit teams and from our regional inspection team.

MEMBER ABDEL-KHALIK: The two components for which the cumulative usage factor is greater than one --

MR. MAURICE HEATH: Yes.

MEMBER ABDEL-KHALIK: -- was the number of cycles that was assumed in the analysis done based on just linear extrapolation of history?

MR. MAURICE HEATH: I'm going to turn it over.

MR. MEDOFF: This is Jim Medoff of the staff again.

Although I didn't do the fatigue analysis, I was involved with the final concurrence on the LRA, but my understanding is that since the environmental CUFs are not required for the current operating basis, they used the 60-year cycle projections for the transience to do their environmental CUF calculations.

For the two components where the CUFs, environmental CUFs have been determined to be in excess of one, they're using the fatigue monitoring program to count the transients that are involved in those calculations, and then if they get close to their allowable, they'll take the prompt corrective action. It could be re-analysis or repair and replacement, and they do have a commitment on that.

MEMBER ABDEL-KHALIK: The question pertains to the analysis that produced a result greater than one.

MR. MEDOFF: Right. What had happened is my understanding is they had one a re-analysis using some updated transients for those components, and staff had reviewed the re-analysis by the applicant and found it acceptable. The discrepancy that the staff found was that the original design basis document for the original CUFs, the transients for those were not the same as the transients in the updated analysis. So there was a confirmatory item to update the design spec based on the revised transients that were used in the original analysis.

MEMBER BROWN: Were the new transients more severe than the previous one?

MR. MEDOFF: Since I didn't do the review, that I couldn't answer, but I could get back to you on that.

MEMBER ARMIJO: What components were these?

MR. MAURICE HEATH: These were the surge line and the pressurizer lower head penetration, were the ones that were greater than one, the ones you are talking about.

Do we have anymore questions on any of that?

MEMBER BROWN: What was the other one? Surge line what?

MR. MAURICE HEATH: Surge line, pressurizer lower head penetration.

MEMBER ARMIJO: Two locations.

MR. MAURICE HEATH: Yes.

MEMBER STETKAR: Anything more?

Maurice, thank you very much.

MR. MAURICE HEATH: Thank you.

MR. HOLIAN: Just one other item. Brian Holian again.

To clarify from a previous discussion, and I don't know if we need to add much to it, but that was the issue of the water in the manholes, and there was a 2002 info notice that went out kind of to the industry on that aspects. So I just wanted to remind the committee of that, and I know there has been discussion amongst the Electric Branch on that, of whether a need industry-wide to update that or not.

We are finding that in other plants as we're doing our inspections and audits so that Generic Communications has been looking at that issue.

MEMBER STETKAR: I think EPRI also has a program. They're concerned about this wet and dry-out issue on underground cables also. I don't actually know exactly what the status of that is right now, but it is an issue that the industry is aware of and concerned about.

Thank you very much.

Any other questions, discussion?

VICE CHAIRMAN BONACA: Well, at the Subcommittee meeting we talked about DLAs, how they were met, et cetera. I'm not sure that this is being communicated through the Committee.

MEMBER CORRADINI: I want to just ask the Subcommittee. So you're comfortable with the classification of (a)(2) versus (a)(1)?

MEMBER MAYNARD: I am.

MEMBER CORRADINI: I mean, this was a discussion point. I want to make sure.

MEMBER STETKAR: I'm not going to speak for the rest of the Committee members. Personally I'd have to say yes, from a technical -- knowing the pieces of equipment, the failure modes, purely technical, not a regulatory legal interpretation. I'd feel comfortable with that.

How we got there is a different issue.

MEMBER CORRADINI: I don't want to see the sausage making.

MEMBER STETKAR: Indeed. Anything else?

MEMBER BROWN: Yeah, I guess I'll just ask the dumb question. The two CUFs on the surge line an whatever, the pressurizer penetration, I asked a question about did they change based on plant previous operating history, did they redo that analysis with a different set of transients. So those are big pipes, and if they break, there's major consequences to them.

And I realize you can monitor fatigue based on the monitoring program, but was there a reason for changing or now obtaining the new numbers? I didn't get a real crisp answer on that.

CHAIRMAN SHACK: Well, for one thing, those were environmental fatigue, which wouldn't have been in the original design.

MEMBER BROWN: Tell me that again.

CHAIRMAN SHACK: It means that you have to take into account the fact that the light water reactor environment decreases the fatigue life typically.

MEMBER BROWN: But it's an internal environment, not external.

CHAIRMAN SHACK: Yeah. It's the internal water environment.

MEMBER BROWN: So you still have the water coming in and out and the thermal shocks, all the rest of the stuff.

CHAIRMAN SHACK: Just the fact that it's in water rather than air. The ASME code fatigue line that these things were originally designed to was based on fatigue life and air.

MEMBER BROWN: Okay.

CHAIRMAN SHACK: Since then we've found that fatigue life in water can be, in fact, considerably shorter than the fatigue life in air, and so they have to take that into account in this, and so that gives them a different projection than they would get if they were using the air curve again.

MEMBER BROWN: Okay. Now, if I had been in that position, I'm just trying to think what I might have done. Would I then explore my past operations to see if my projection would be that I will really exceed the fatigue life within my plant licensing? It says you will, but look at actual operations to see if I really have the potential to do that.

CHAIRMAN SHACK: Well, they've done more. They're going ot actually monitor their cycles, and they'll just track this.

MEMBER BROWN: No, I understand that. I understand that point. I was just saying if I look at my past, they've got 20 years of plant history.

CHAIRMAN SHACK: Well, we never did get an answer to that, whether this was a projection based on past history or just a --

MEMBER BROWN: Yeah, and that's I --

CHAIRMAN SHACK: -- fraction of an original design spec. That was the question that Said was trying to ask.

MEMBER BROWN: And I was trying to pull the string on that.

CHAIRMAN SHACK: That never did get answered, but you know, the critical thing from my point of view is that, in fact, they're going to be --

MEMBER ARMIJO: They're here. Everybody is here. Let's get an answer. What is?

MR. MALLNER: My name is Chris Mallner, and I'll answer that question for you.

Originally, when we put together the license renewal application and did these analyses, we had used straight line projections for cycles. During the review, there were some questions on the validity of using straight line projections.

Subsequent to the original analysis and in discussions with the staff during our audits, we used a full set of design transients to analyze all the locations. Therefore, we used no transient projections whatsoever. So we don't base anything on saying that, for example, if we have 200 heat-ups and cool-downs in our design specification that we can project we're only going to have 133.

No, we've looked at environmental fatigue with the full set of design transients for the plant. So there are no projections for Harris license renewal at all.

Now, for the fatigue monitoring program, we go back and look at how much we've accumulated in the past by reviewing past operating histories, and that all gets built into the fatigue monitoring software that we're using that was supplied by Westinghouse called WESTEMS, and that provides the models where you can pull the information off the plant computers and provide the delta accumulation of fatigue over the life of the plant, and we will monitor the fatigue accumulation over time, and we have alarms built into our fatigue management program that will allow us to have sufficient time to either replace, replace, re-analyze or whatever the corrective action would be appropriate for those locations.

CHAIRMAN SHACK: But that sounds like a linear -- I mean, if you had 200 cycles for 40 years, you would presumably have 300 cycles for 60 years. Is that what you did?

MR. MALLNER: What we did is use 200 cycles. We used what's in our design specification. Now, the --

CHAIRMAN SHACK: That seems peculiar.

MR. MALLNER: Now, the issue of --

CHAIRMAN SHACK: The design spec was for 40 years.

MR. MALLNER: That's correct, and we said we're going to maintain the design specification number of cycles for 60 years.

MEMBER BROWN: Is that consistent with what your monitoring program to date? In 20 years you then have used only less than a third of the design transient cycles, however it's calculated?

MR. MALLNER: Now, the issue, of course, most importantly is that we are tracking, for those locations, we are tracking accumulated fatigue. So if we were to have a heat-up or cool-down, for example, that happened at less than the design heat-up and cool-down rate, that would accumulate less fatigue for that particular cycle.

But we're tracking fatigue. The goal of the fatigue monitoring program is to insure that the component has a CUF less than or equal to 1.0, not to control the number of cycles per se, because what our code requirement is is to maintain the CUF less than or equal to one, and that's what the program does.

It's just counting the cycles is an adjunct to insuring that the component remains qualified during the entire operating period.

MEMBER ABDEL-KHALIK: And you do have enough data that would allow you to account for everything that happened in the past?

MR. MALLNER: What we did is we looked back at actual operating data for about between five and six years, and we looked at all the data and used that as part of our analysis of the previous cycles, and that gave us an understanding of how the plant operated in the past.

Going forward, obviously the plant is instrumented, and we use that information and feed that into the WESTEMS software to come up with the delta accumulation of fatigue for every present and future cycle.

CHAIRMAN SHACK: Okay, but that backward review, is that what gave you the confidence that the 200 that you had for 40 years was, in fact, bounding for 60 years?

MR. MALLNER: Well, yes. See, the reality of this is that we're using our accumulation to date and our cycles to date to help us design an alarm limit to provide sufficient time for us to do corrective actions. We don't want to bump on the CUF of one and have no time to do anything and be forced to shut down the plant. We want to have sufficient time to be able to manage this, which is the idea that fatigue management program.

I just want to add our update to the design specification was really backwards looking. It goes back to our --

MEMBER ARMIJO: I'm getting more confused.

MR. MALLNER: Okay.

MEMBER ARMIJO: What is your CUFen right now for those two pressurizer components?

MR. MALLNER: It's less than one.

MEMBER ARMIJO: Give me a number, not

"less than one." It is .3, .2? What is it?

MR. MALLNER: One of the locations was approximately between .8 and .9. However, that location has been --

MEMBER ARMIJO: That's close to one.

MR. MALLNER: It looks high. However, that location has been mitigated as part of our alloy 600 program. There's a weld overlay, and the analysis was revised, and that location is not near that. It's very low now.

MEMBER ARMIJO: Okay.

MR. MALLNER: So obviously when we go in there and do other repairs, replacements that affect those locations, we have to update the fatigue analysis as required.

MEMBER ARMIJO: So you're saying because of stress corrosion cracking issues, you put this big weld overlay.

MR. MALLNER: That's correct.

MEMBER ARMIJO: And that somehow compensated for the fatigue usage phenomenon.

MR. MALLNER: Right. It moves the location someplace else.

CHAIRMAN SHACK: It reduces the stresses of that particular location.

MEMBER ARMIJO: Sure.

CHAIRMAN SHACK: And he's still going to have cycles, but he's going to accumulate no usage.

MEMBER ARMIJO: So it's like starting with a new pipe.

CHAIRMAN SHACK: Well, no. It's going to be .8 and it's going to stay .8. It isn't going to get any better, but it's not going to get any worse because he has now reduced the stresses at that location because of the overlay.

MR. MALLNER: I would like to interject, if I could. One of the drivers was the way we had operating procedures in the paste, and years ago we changed or modified operating procedures, and the accumulation now is much lower than it was in the past, and we accounted for the way we used to operate the plant in the old days in the calculations, but our accumulation based on our modified operating procedures is much lower.

Big picture though is that these locations are within our fatigue management program. We monitor them, and we have a program manager who looks at these locations, tracks the cycles, looks at the accumulation, and has alarm limits that trigger the corrective action program to do whatever is required for repair, replacement, re-analysis or inspections, whatever they decide is appropriate for those locations.

MEMBER ABDEL-KHALIK: What are those alarm limits, .9, .95, .99?

MR. MALLNER: The alarm limits, we're working on the -- because we did the weld overlays, we are working on looking at what we're going to make those alarm rates again. We're going to change them now because we can change them to something that will be more appropriate after they've been repaired.

But right now that procedure that we use for this program is being revised now, and we're looking to reissue it before the end of the year. So we're going to go review the alarm limits once again.

But, again, that's part of the overall license rule implementation plan that we have.

MEMBER ARMIJO: Yeah, I'm kind of troubled because you put those weld overlays without inspection, as I understand. You didn't inspect those welds. You just overlayed to address the stress --

MR. MALLNER: I would have to refer to the plant whether these were preempted.

MEMBER ARMIJO: I think I read in the SER or in your application that they were just a preemptive overlay. I'm not -- correct me if I'm wrong, but okay. Let's say --

CHAIRMAN SHACK: He probably wouldn't believe the inspection anyway.

(Laughter.)

MEMBER ARMIJO: But then you have to make an assumption that there might be some stress corrosion cracks there. Now, I've got this other phenomenon of environmental fatigue on top of that. I'm just wondering how all of this works together, fits together so that you can have confidence in your analysis that the CUF is meaningful as far as structural integrity.

So has the staff looked at that?

CHAIRMAN SHACK: CUF is meaningless once you've got a crack. CUF is an initiation thing. So what you need essentially is a flaw tolerance analysis, which I assume that you do with the overlay because you've assumed -- the overlay assumes essentially a full 360 through-wall crack.

MR. MALLNER: If I could interject again, the --

MEMBER ARMIJO: When you have a crack already there, it would be different if you have an initiator.

MR. MALLNER: When you do the weld overlay, there will be two parts. You'll have to redo your Section 3 analysis, which includes the CUF, and you do a flaw tolerance evaluation to meet the requirements of Section 11. It's two piece, parts to it.

MEMBER ARMIJO: Yeah, I'll have to think about it some more unless the staff would like to help me out here. Because I think, you know, you could start with the assumption you've got a crack in that component caused by stress corrosion cracking. You didn't inspect it. So you don't know, but you overlaid it just because there might be.

MR. MALLNER: The mitigation has been performed.

MEMBER ARMIJO: Yea, right. So now you've got potentially a crack. Do you assume that in your fatigue analysis, that there will be fatigue nucleation a lot faster because of the existence of that crack into the weld overlay?

How does this all work?

MR. MEDOFF: I think you've got a certain perspective of -- this is Jim Medoff of the staff again -- the thing about the CUF in that analyses is they're based on design basis calculations which sort of go into the premise that if your CUF is going to be less than one, any micro cracks in the structure won't go and coalesce into a micro crack.

Dr. Shack is correct that once you get a crack, a macro crack in the component, the CUF calculations are basically meaningless. You already have a macro crack.

MEMBER ARMIJO: They're nucleation --

MR. MEDOFF: Right, right. So if they have a component that has a macro crack, a nozzle, for instance, that they put on a weld overlay. The ASME code has come up with an NRC approved code case that they use for these overlays, and the code case requires a flaw tolerance, a flaw growth analysis of the original flaw because the original flaw has grown through wall. They have slapped some overlay weld metal on top of that.

What happens is from what we've heard from the industry is that the overlay has put the cracks in compression. So the crack, existing crack won't grow into the overlay weld metal. So it addresses it that way.

MEMBER ARMIJO: All right. I understand you.

MEMBER ABDEL-KHALIK: Now, you indicated

that one of these two locations has or maybe already has been taken care of with the overlay. How about the other location? What is the cumulative usage factor in the other location?

MR. MALLNER: At that other location, I can't give you the number off the top of my head. It's probably in the range of about .8. I can't tell you exactly. I'd have to go look it up. I'd have to call up the program manager and have him pull the latest number off the software.

MEMBER ABDEL-KHALIK: And the plan is to just simply monitor this and when you reach some alarm value, then you come --

MR. MALLNER: We have to take some compensatory measures.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER STETKAR: Anything else? Anyone?

(No response.)

MEMBER STETKAR: With that, Mr. Chairman, it's yours.

CHAIRMAN SHACK: Okay. Thank you, gentlemen. Thank you, staff and the licensee, for a good presentation.

With that, we'll take a break until 10:15.

(Whereupon, the foregoing matter went off the record at 10:02 a.m. and went back on the record at 10:18 a.m.)

CHAIRMAN SHACK: Gentlemen, we can come back into session.

MEMBER BANERJEE: Is it in my hands, Mr. Chairman?

CHAIRMAN SHACK: Yes. Our next topic is Generic Safety Issue 191, and Sanjoy will be in charge.

MEMBER BANERJEE: Okay. So all the new members, maybe I should give you a little introduction to GSI-191, you know, what it's all about.

So to begin with, it's a concern with long-term cooling of the core. Okay? And the concern is following an accident like the loss of coolant accident, you generate some debris and there are screens in front of the pumps which are supposed to take out this debris, and of course, what you're concerned about is that the pumps shouldn't fail or get closed up or the core shouldn't get clogged up.

So if you can think of the screens, they're put in front of the pumps hopefully to take the debris out and so that the debris doesn't get to the core or to the pumps. That's the purpose. Okay?

Now, what happened? This has been a long-term issue. If you look back in history, in 1979 it was an unresolved safety issue A-41 or something. I don't remember, but in any case, it came to prominence in 1992 with Barsaback 2. You may remember, for those of you who were not involved in this, that a lot more fiber got to the strainers in the BWR than anticipated, and that opened the subject to examination for BWRs.

And eventually what happened is they put much larger screens in to take care of the problem, and remember that BWRs don't have a lot of chemistry problems which you'll see come up, and they have less insulation and things that get into the sump, what was these TORI (phonetic), and things like that.

Now, what happened is later on there were two evaluations done as to whether this could affect PWRs. One of them showed -- and this was NUREG whatever. I forget the number -- that the CDF increased by an order of magnitude if you considered the plugging of the screens, the existing screens.

The second showed that I think about 53 of the 69 plants were affected. There was a study done. This is another NUREG whose number I forget. At any rate, the upshot of all of this was that we had to open this issue and look at it for PWRs. What happens if debris gets in? So it's all brought up in Barsaback.

Of course, we started to look at this in conjunction with the staff who came to make various presentations. Eventually GSI-191 was opened. It's still an unresolved issue, and this has to do, as I said, with the concern regarding long-term cooling of the core with this debris.

We wrote letters, September 30th, 2003, several letters in 2004. The most recent letter was April 2006. Now, as we're going to write a letter again, let me set the stage by telling you what we said in the 2006 letter.

The first thing we concurred with the staff who had recommended that the utilities install larger screens. We thought that even though this might not take care of all the problems, this was a good thing to do. Okay? So that was our concurrence.

However, we were skeptical that it would really resolve the issue and pointed out several things.

One, we said in our letter that prototypical experiments were required in order to be able to extrapolate from these test conditions to plant conditions. I think that's still an open question that you guys need to consider. Okay? There was concern about writing a letter.

The second thing is that we said that there would need to be improved guidance and predicted methods as to how to deal with chemical effects and fiber and particle mixed beds.

The third thing we said was that increasing screen sizes may allow more stuff through and give rise to downstream effects.

So these were the three sort of things in the sense that more material now may get through these screens even though you have a lower pressure loss and get to the core or whatever and start to block this.

Now, I want you to think of this in a way before this presentation as being two screens here. One of these screens is the screen which is supposed to take most of the debris out, but in fact, the core itself has rather small openings. So it acts as a screen as well. Basically you have two screens in series here.

And the concern really is whether in this last point I'm talking about, whether the stuff that gets through the first screen ends up in the second screen, which is the core and then starts to block it. Okay. So this is really setting the stage for what they're going to say.

Now, I want to warn you about one other point when you look at this because this will come out of the blue for most of the new members. It's a very, very complicated issue obviously and regulatory nightmare because there are dimensions related to chemicals, how much debris is formed, the particular geometries of the containment, where the flow is going through, the particular screens which are being installed, which are all sorts of different screens, the parts to the core and so on.

So in this multi-dimensional space, the staff are trying to find a way, and it's not easy because obviously each time they look at something, some other issue pops up, you know, even taking a ballistic effect sort of approach is difficult.

At some point we suggested a risk informed approach. I looked ion the letters way back, but even that, I mean, is difficult to take in this case.

So in that context, you should look at this and clearly what we're looking at here is what path forward is there to closing out this issue, and this is really what the staff are going to present to you today.

Okay? Go ahead.

MEMBER APOSTOLAKIS: It seems to me as you just pointed out that this is a very complex issue and one can have several research projects going on for years. I'm wondering as you said this activation cooling is needed after a LOCA, and a LOCA of pretty good size actually. Now, the frequency of that LOCA is less than ten to the minus five according to here, according to various estimates, if not significantly less.

What role does this play in all of this evaluation? The fact that we're talking about phenomena that, you know, may be needed after such a very rare event, does that affect our thinking? I mean, I'm getting the impression sometimes that we are viewing this as a research project in its own right, and we want to understand this. We want to understand that. I mean, to what extent should we really understand what may happen and then say this is good enough?

MEMBER BANERJEE: I think we should have the staff wants.

MR. RUTLAND: This is Bill Rutland. I'm the Division Director for the Division of Safety Systems.

And it's our responsibility along with

Office of Research and the Division of Component Integrity to disposition this issue. The staff is faced with assuring that the licensees comply with 50.46, the long-term cooling criteria, and it is a question for us about do licensees comply with our rules, and the Commission on a number of occasions has suggested to the staff because they understood the relative infrequent nature of very large LOCAs, they have both suggested to us a holistic review which the staff is performing, and we'll go into that, what we mean by "holistic review," and they have also suggested that we look for realistic scenarios.

And as a matter of fact, that notion for us to look for realistic scenarios came out of an SRM that was basically from an ACRS meeting on this topic. So that's how the staff has tried to incorporate the notion that this is a very low frequency event.

In addition, since it is a low frequency event, that, frankly, has given us the time to, you know, work on this problem. When we issue extension letters to licensees, one of the things we say is because of the relatively low frequency of this event and the unlikely nature of actually having this problem, that gives us the opportunity to resolve this in a more reasonable manner.

MEMBER APOSTOLAKIS: But I don't understand what the holistic approach is.

MEMBER BANERJEE: Maybe they will explain that.

MEMBER APOSTOLAKIS: We're looking at realistic scenarios. Still, okay, you are looking at scenarios, but how far do you want to push the state of knowledge? That's really the question.

MR. RUTLAND: And what I think you're going to hear from the staff today is a set of really engineering testing that has been performed. To some extent some of these technical areas that we're looking at do not have analytical models to support them. We often rely on conservative assumptions based on our engineering judgment.

And as you have eloquently pointed out, and as I have said, this could take, you know, two lifetimes to do the research, to really completely understand the phenomenon.

So hopefully at the end of this presentation you can ask that question again to us, but that is precisely the heart of the matter when you're trying to address this issue.

So before I get the staff to start, I just want to say just to just a very few words. That was a great lead-in for my discussion about what you're going to hear. And to some extent it's engineering judgment, and these are engineering tests that we are relying on, and we have asked for conservative pieces to all of the individual technical areas and finally we're looking for a letter, if possible that the ACRS could say they understand or endorse or agree with or don't object to, whichever you wisely think of.

MEMBER APOSTOLAKIS: So this is an issue then of design basis.

MR. RUTLAND: That's correct.

MEMBER APOSTOLAKIS: Let me ask a hypothetical question. You're familiar with an effort to risk inform 50.46.

MR. RUTLAND: And I'm responsible for that, too.

MEMBER APOSTOLAKIS: Okay. You are. If that had been approved, would it have changed anything here?

MR. RUTLAND: Yes, it could have.

MEMBER APOSTOLAKIS: It would have.

MR. RUTLAND: It could have, yes.

MEMBER APOSTOLAKIS: Could have.

MR. RUTLAND: Well, licensees would have to adopt 50.46(a), and then they could, in fact, avail themselves of that, yes.

MEMBER APOSTOLAKIS: As you very well know, sizes above the transition break size --

MR. RUTLAND: Correct.

MEMBER APOSTOLAKIS: -- which was going to be something like 12 inches for BRWs, whatever, would not be treated as design basis.

MR. RUTLAND: Correct.

MEMBER BANERJEE: But I should warn you that the Germans do this and the problem doesn't go away.

MR. RUTLAND: Entirely, correct.

MEMBER BANERJEE: They don't look at, you know, their debris generation and things are for relatively small breaks.

MEMBER APOSTOLAKIS: I think the --

MEMBER BANERJEE: And it's the amount of debris actually is -- the problem doesn't only arise from the amount of debris. There are two separate issues. If you generate debris in small quantities even, but of a certain type, it can have as deleterious an effect as larger amounts of debris, you know. So there are many issues. This is a very multi-dimensional problem. So you're not going forward.

MEMBER APOSTOLAKIS: And I'm not saying that the issue goes way. All I'm --

MEMBER BANERJEE: Actually it can get worse in some cases.

MEMBER APOSTOLAKIS: All I'm asking is because it's a condition of event after a failure event, to what extent do we need to understand it.

MEMBER BANERJEE: That's a different issue.

MEMBER APOSTOLAKIS: But that's an important issue.

MEMBER BLEY: At least for me there's a related question, and maybe this is an easy one to dispense with. Given there was the real Barsaback event, how does that event align with the current issue? I mean there's a real thing that happened.

MR. RUTLAND: One of the things that the -- can we talk about the BWR disparities a little bit in this, in your presentation?

Just briefly, the staff has asked the question. We have learned an awful lot about chemical effects during this process. When the Barsaback event happened and Limerick, chemical effects really weren't addressed. So we have gone back to the BW Owners Group to engage them to say, "Okay. We can to solve this complete. We don't want to go PWRs, BWRs, back and forth. We want to go back to the boilers," and they're working with us.

I think there's a meeting what, next week?

MR. HARRISON: Yes.

MR. RUTLAND: Next week the BWR Owners Group is meeting on this matter, and we're going to join that meeting. So we're trying to address that issue, too.

MEMBER APOSTOLAKIS: Just would you please remind us very quickly in Barsaback, I mean, you would not have any kind of recirculation or we were surprised because there was some blockage? I don't remember.

MEMBER BANERJEE: There was quite a bit of blockage.

MEMBER APOSTOLAKIS: Quite a bit. Now, what does that mean, "quite a bit"?

MEMBER BANERJEE: If I remember, the strainers bent and all sorts of things happened

MR. RUTLAND: And we have tried and I think you'll hear today, tried to make that determination. You'll see pictures of strainers that look like they've got a lot of stuff on them, and that's not the criteria. The criteria was sufficient flow, was sufficient net positive suction head for the pumps, and you'll hear that today.

CHAIRMAN SHACK: Sanjoy, in order to get through the technical presentation today, we're going to have to get started here.

MR. RUTLAND: Thank you, Mr. Chairman.

MEMBER APOSTOLAKIS: It's very important though because it sets the point of view.

CHAIRMAN SHACK: Well, but I mean, I think we can discuss that in our own session. I think we need to get through this technical discussion today.

MR. RUTLAND: Thank you, Mr. Chairman.

Take it away, Donnie.

MR. HARRISON: Thank you.

I'm Donnie Harrison, and I'm the Branch Chief for the Safety Issues Branch currently while Mike Scott is on rotation in Region 1.

Today we're going to discuss the generic letter closure process. We're going to discuss a number of selected areas that are currently under review, and those involve the strainer head loss testing. Steve is going to follow my presentation with a discussion on that, and then we'll talk about chemical effects, in-vessel downstream effects, and some trace calculations, hand calculations that were performed on fuel inlet blockage.

I'll try to quickly go through a broad overview of the process and how we're approaching closure.

First, just as a quick background to the issue, I believe Dr. Banerjee gave a good intro. What that has led us to under Generic Safety Issue 191 was an assessment of sump blockage, sump performance. In 2003 we issued a bulletin, 2003-01, that requested licensees to confirm regulatory compliance that their sumps actually could perform as required.

Those that did not have the analysis or capability to do the analysis at the time, we asked them to describe their interim compensatory measures that they would implement to reduce risk until those analysis could be performed and any actions that could be taken in response.

All of the licensees responded. Those recognized at the time that the methodologies haven't been developed for performing the evaluations at that time. That led to Generic Letter 2004-02, where licensees were requested to perform the actual analysis of the support or a mechanistic evaluation of the sumps. Most licensees requested and received extensions to that generic letter. It's original date was December of 2007 for it to be closed. Most licensees received extensions and were under those reviews. Those extensions were to allow them to complete their testing and the analysis and any corrective actions they had to implement.

With that I'll jump to the current status on GSI-191. All licensees have installed significantly larger strainers.

MEMBER BLEY: These are already in place, right?

MR. HARRISON: These are already in place. Yeah, this has already been done.

MEMBER BROWN: By larger do you mean physically or just bigger whole sizes.

MR. HARRISON: Physically.

MEMBER BROWN: These are more square feet.

MR. HARRISON: Upwards of 8,000 square feet.

MEMBER BROWN: Okay. I saw that in the write-up. I just didn't know how. Okay.

MR. HARRISON: Significantly larger.

MEMBER BROWN: Was the sump strainer size? I mean is it large by one inch or --

MEMBER BANERJEE: One inch to one-sixteenth.

MR. HARRISON: One-sixteenth? I think there might be a handful of UP TO --

MEMBER BANERJEE: And they're not simple holes.

MEMBER BROWN: Okay. One-sixteenth to one-eighth inch, something like that?

MR. HARRISON: I think there's a handful that would be a little bit more --

MR. RUTLAND: Okay.

MEMBER CORRADINI: The hole itself.

MR. HARRISON: Yeah.

MEMBER BROWN: The strainer holes, lots of holes.

MR. HARRISON: Yeah.

MEMBER BROWN: Okay.

MR. HARRISON: In addition to installing significantly larger sump strainers, licensees have also done a number of other modifications. A number of licensees have removed insulation to reduce their, if you will, exposure to debris. Some have beefed up their banding of the insulation so that it's less likely to come off.

A number have reduced the sump buffer or replaced the sump buffer. Some have installed debris interceptors, and there's at least one plant that's pursuing a water management where they control containment sprays.

In addition, at least all licensees have performed some strainer testing to try to address the generic letter. I say here they performed it. No everyone has completed their strainer testing because some may have to go back and retest in response to the staff review and establishing a proper path for each closure on the generic letter.

Again, as I said before, most licensees requested extensions beyond the December date for the generic letter. This was to allow them to implement additional testing to address the downstream effects analysis that was raised. Questions were raised at the subcommittee back in March of this year, and licensees are addressing that, and to perform plant modifications.

The staff is nearing its completion of the licensee's responses to the generic letter and the supplemental responses. You'll hear more about that in a minute.

There's a pictorial basically showing how the closure process, how we're approaching closure for this generic letter. At the far left we'll walk through this slide with the following slides, but basically an overview of licensees make a submittal on the generic letter to the staff. We perform a detailed staff review. Out of that detailed staff review and 14 different technical areas, draft RAIs developed. That then feeds into an integration review team. Again, we'll talk about that in a few minutes. That integration review team's charter is to do a holistic review, to review the RAIs, the staff review, and the actual application and make a determination as to if the issue can be closed.

That recommendation is said to management to make a decision on closure and either we document closure of the issue or we feed those RAIs to the licensee. Again, we'll walk through this in a little more detail.

MEMBER BANERJEE: I think you should mention that there is a set of review guidance which is available.

MR. HARRISON: yeah, there is review guidance for performing a number of the staff reviews and for doing the testing that the licensees might perform.

MEMBER BANERJEE: And this IRT team not only asks questions of the licensee, but also of the staff doing the review.

MR. HARRISON: yeah, and there's a little failure, and this will be discussed in a couple of slides, but interaction between the two teams.

MEMBER APOSTOLAKIS: Is this the way we close all of the issues? I mean, is there anything unique here about --

MR. HARRISON: The unique piece here I would say is the integration review team. They're actually stepping back after the staff does its traditional review of the acquisition and stepping back looking at the broad perspective of the issue and saying -- looking at the conservatisms, the uncertainties in the issue, and making a determination as to can we close this or do we need to pursue this additional --

MEMBER APOSTOLAKIS: So that's where this issue --

MR. HARRISON: That's where the whole issue of review comes to a head.

MEMBER ARMIJO: Will the same integration review team review all of the licensee submittals to try and come up with some consistency?

MR. HARRISON: Yeah, and you'll hear that in a couple of slides, but yes. It's essentially the same.

MEMBER BANERJEE: But there's an overlap always.

MR. HARRISON: There's a couple of members that have come and gone, but it's basically the same three to four staff members that sit on that integration review team, and again, in a couple of slides we'll actually get to that.

Okay. The licensee submittal, the first block on that diagram, they provided their initial response to the generic letter. All plants provide supplements in the February-March time frame. They'll also need to respond to any RAIs. They'll respond to any open items that were identified at a staff audit that may have been performed at their plant or on their testing.

After they've completed all of their testing and evaluations, they need to provide a final supplement that says this is what we've done, and looking forward, if they're relying on this downstream effects topical report that the PWR Owners Group is doing, they would need to address that after that has been issued and approved by the staff.

The detailed staff review, the second block in the diagram, what I did on this slide was identify basically the technical areas that are reviewed by the staff. It usually involves about ten staff members from DSS, DCI, and Design Engineering, DE, for the structural part.

The output of this initial review, again, is a set of draft RAIs from the staff written in their particular review areas. We're about 60 percent of the way through those detailed reviews. We plan to have the at least initial review completed by the end of October.

MEMBER APOSTOLAKIS: Can you tell us what break selection means?

MR. SMITH: The break selection is basically where the licensees consider different breaks that could happen in the RCS, and they try to determine which break would be the limiting break for their situation or there may be more than one. There may be two or three that they have to evaluate further down the road.

MEMBER APOSTOLAKIS: This is different from what they have already done to get the license?

MR. SMITH: Yes, this is different because --

MEMBER APOSTOLAKIS: -- 50.46, isn't it?

MR. SMITH: The break selection in this case determines how much debris is going to be generated.

MEMBER APOSTOLAKIS: Also it's a different criterion.

MR. SMITH: Yes.

MEMBER APOSTOLAKIS: You are looking --

MR. SMITH: And how it's going to transport to the strainer and things like that. So there's additional evaluation.

MEMBER APOSTOLAKIS: These breaks, do we usually have some idea of the size?

MR. SMITH: Generally the limiting breaks, you talk about a double-ended guillotine break of your largest RCS pipe would be your largest break. You may not be limiting. You have a smaller break that could create more debris.

MEMBER CORRADINI: So I guess that gets to the point that --

MEMBER BANERJEE: Or a different type of debris.

MR. SMITH: Or a different type of debris, right.

MEMBER CORRADINI: So you have to look at the spectrum.

MEMBER APOSTOLAKIS: But it's a fairly sizable break.

MEMBER CORRADINI: So just to make sure the way you answer, George, so what would be the limiting break size for the thermal hydraulic analysis to show coolability to stay within peak clad temperature is not necessarily the break that's going to generate the debris that you then worry about gets plugging for the largest one.

So there's an inconsistency between the debris --

MEMBER BANERJEE: This is long-term cooling remember.

MEMBER CORRADINI: Well, but it doesn't matter. If they're limited by peak clad temperature and that drives them for a certain break that then they have to show long-term cooling, there is not the same debris loading from that same thing. It's the biggest of the two together.

MEMBER BANERJEE: Well, there are two separate criteria for the analysis.

MEMBER POWER: If we are going to rehash issues that have been known for five years, it's going to take a long time to get through this.

MEMBER CORRADINI: I just want to make sure I understood. I'm sorry.

MEMBER BLEY: Well, I'm sorry, but I have to ask one regardless. Two related questions. How big was the Barsaback break?

And, two, was there an experimental program to look at different kinds of breaks and what kind of debris is generated by them with different kinds of insulation or is it all analysis?

MR. HARRISON: Again, I think Barsaback wasn't actually a physical break.

MEMBER BROWN: It's a pilot operated relief valve.

MEMBER BLEY: Okay.

MR. HARRISON: In a steam line.

MEMBER BLEY: But that's not a really big pull, and it generated a whole lot of debris.

MR. SMITH: The break process, since there hasn't been a lot of evaluation about what different breaks would create, you know, different debris, we try to be conservative with that, with our break selection and pre-generation evaluation.

MEMBER BLEY: In centrally analysis or were there experiments done?

MR. SMITH: There was some experiments done to determine different zones of influences or, you know, what pressure it would take to create damage for certain types of debris. There was experiments done for that.

MEMBER BANERJEE: I think the Committee should know that ACRS considered this in a lot of detail in the past and had some concerns about certain things which I don't want to go into right now, but let's say that we have an agreed on sort of methodology for generating debris in how to do this stuff on this side, on the generation side.

MR. HARRISON: If I may go ahead on the integration review team, the team consists of three senior technical staff, including senior level SLs. The membership of that has only been five members in total. One has only reviewed one IRT. There has been one member that's been on every one of the IRTs and another member that's been, I think, on every one except for one IRT.

So the goal there is to have a consistent team membership, to do a holistic review. Again, they step back from the actual review. They review the application, the information from the licensee, the staff's detailed review. They look at the RAIs. They interact with the staff to make sure there's understanding on both sides on what's being sought through the RAIs, and they make a determination regarding the need for pursuing additional information or if there's adequate, sufficient information to support reasonable assurance that the sump performance is achieved.

Currently we're about halfway through the IRT phase as we've progressed towards plant reviews that have considerably more fiber. We've been doing a screening process on the IRT that an IRT member leads this effort. He believes that because of the fiber amount or for other reasons, that we will for sure be going back to the licensee with RAIs. We'll, if you will, by pass the IRT and just go straight to requesting the additional information.

MEMBER APOSTOLAKIS: So this sub-bullet, staff has informed several licensees with more fiber that the staff has a few RAIs. That's what you mean, a few RAIs.

MR. HARRISON: Yeah, it has a few.

MEMBER APOSTOLAKIS: A few. It makes a big difference.

MR. HARRISON: Yeah, yeah. For those plants that are low fiber, typically --

MEMBER APOSTOLAKIS: It does.

MR. HARRISON: -- we've had a few plants that have just gotten a very limited number of RAIs. We've had one licensee for their plants that did not get any RAIs. Most other plants have received RAIs or will receive RAIs, and in addition, we have a place order RAI dealing with the in-vessel downstream effects since it's still, I'll say, under development, under consideration.

MEMBER BANERJEE: There is one plant, I think, that has got yeses in both. I was looking at the chart, right? So even one of those doesn't have any downstream effect.

MR. HARRISON: Right. There's one plant that has so little fiber that they were informed that we would not be pursuing any RAIs related to the strainer or downstream effects. So that licensee's three plants is where the staff believes is pretty much through the process.

MEMBER BLEY: Given they had so little fiber, did they also though have to put in a bigger strainer?

MR. HARRISON: They also installed a larger strainer. That's the counterbalancing.

For closure of these issues as we go through, the staff reviews the supplement information, the licensee's RAI responses in accordance with that process that I laid out earlier. The regions inspect the implementation of any modifications or any other commitments for procedure changes or whatever.

After a licensee provides sufficient information to be determined to have closed the issue, we'll --

MEMBER APOSTOLAKIS: This is a judgment at this time.

MR. HARRISON: This becomes a judgment of the staff, and it's the staff, the IRT, and the management become aligned on closing out the issue. At that point then we'll issue a closure letter to individual plants.

After we close the issue for all the plants, then we'll formally close the generic letter. Recognize that even after we close the generic letter, some plants may have to perform plant modifications to be able to be at the right place to support the closure, and they'll make commitments for maybe future outages to take out fiber or something like that to match. Those future activities would be tracked under the normal NRC commitment tracking approach.

Our expectation, our plan is to complete all of the technical reviews by next year to support closure of the issue.

With that I'll turn it over to Steve Smith to talk about the sump strainer testing.

MR. SMITH: Good morning. Steve Smith of NRR.

This is what we're going to talk about this morning. First, just a quick overview. The plants and vendors for the plants are doing plant specific strainer testing to insure that their ECCS and containment spray systems will function during recirculation. The staff has witnessed testing at these vendors and we've applied the lessons learned to assessment of the testing and also applied the lessons learned to our review of their submittals and to some guidance that we put out.

Today we're going to talk about the observations that we've made, the lessons learned regarding head loss testing, a little bit about the review guidance we put out, and a little bit about our review of the responses in the head loss area, and how we see things going forward.

Okay. We have witnessed a number of head loss tests at each vendor, and we've been on about 25 trips and we've been to at least each vendor one time. Each vendor we've seen at least one time, and the ones that we've only seen once only did a limited number of tests.

The lessons learned from watching this testing, we've incorporated into the review guidance that we put out for testing and evaluation of the testing. And we've also incorporated the lessons learned into a review of the licensee's generic letter submittals.

And because of the significant unknowns that we encountered with the head loss testing and evaluation area, we pushed the vendors and the licensees to use conservative test methods and conservative evaluation of the results.

Most strainer vendors or testers, since not all the testers are vendors, have now developed what we consider to be acceptable test practices for testing the strainers. Some vendors haven't come up with a protocol that we consider to be approved. We just haven't seen enough from them that we consider the protocol to be conservative.

And the licensees that use what we consider to be what we haven't approved or what we haven't accepted as a good test practice, they may try to justify the use of this, but in order to do that, they're going to have to answer some questions and show us that they actually had a conservative test that they ran when they tested their strainer.

And we believe that some licensees are going to have to retest in order to show us that their strainers will function properly.

Okay. These are the major lessons learned that we learned when we went out to look at the strainer testing. I just listed four of the major ones there.

The first one is debris preparation, and what we had learned is that, in general, vendors had been using the generic debris preparation where most of them would just throw it through a leaf shredder and then they'd say, "Okay. That's what we're going to test our strainers with."

And what we found was that the debris sizing that they were coming out with after they threw it through the leaf shredder was not matching what their transport evaluation said would end up at the strainer. It was generally coarser and we found that finer debris ends up with a more conservative or it will give you higher head loss if you test with finer debris.

The second one is the debris introduction methods. Even if they prepared the debris properly, they might put the debris into whatever they're going to put it with the test, with a bucket or something like that, and if they didn't have enough water with it, it would just -- even if it was prepared finally, it would agglomerate into like a large clump, and it might just -- when they put it in, it might sink to the bottom of the flume. It wouldn't transport conservatively and get on the strainer in a fine, uniform bed, which would create the most head loss.

MEMBER CORRADINI: This was probably said in the Subcommittee, and I forgot or missed it.

MR. SMITH: Okay.

MEMBER CORRADINI: Has any of you done a test where they actually try to obliterate the insulation with a blow-down? So actually you have a real blow-down with a real sphere of influence so that you see what you really produce?

MEMBER BANERJEE: There were experiments done.

MR. SMITH: Yeah, there was some testing done. Back in the BWR days the majority of the testing was done.

MEMBER CORRADINI: Oh, was there?

MR. SMITH: Now, that debris wasn't taken from that and then put into the test. That was just --

MEMBER CORRADINI: Characterizing the

morphology.

MR. SMITH: That's correct.

MEMBER CORRADINI: Fine. Thank you.

And that's where you did the comparison.

MEMBER BANERJEE: Just to give you -- this is not a completely closed subject, the characteristics of the debris.

MEMBER CORRADINI: Okay. I just couldn't remember. I figured it --

MEMBER BANERJEE: There was some two-phase jet testing done and some air testing.

MEMBER CORRADINI: Okay.

MR. SMITH: The third area was thin bed test protocol. Thin bed may be a new concept to some people. Basically what you're doing when you look for what we call a thin bed is you're looking for a given amount of fiber to become saturated with particulate debris. When the fibrous debris becomes saturated with particulate debris, it creates a very dense and high head loss bed.

So if you have a lot of fiber with a relatively low amount of particulate debris, it may create a much lower head loss than if you have a smaller amount of fiber with the same amount of particulate debris that creates a very dense bed.

MEMBER BANERJEE: This is addressing your question, George, about it doesn't have to be the largest break, which gives you a lot worse effect.

MR. SMITH: That's correct.

MEMBER APOSTOLAKIS: But it's still large. Let's settle that.

MEMBER BANERJEE: Well, large, yes.

MR. SMITH: If it requires recirculation, it's going to be a relatively large break. I mean, it could be not huge, maybe six inches or so. I don't know. Different plants are different.

MEMBER APOSTOLAKIS: Be as low as six inches?

MR. SMITH: Maybe. It might still require a --

MEMBER APOSTOLAKIS: -- minus four, three.

MEMBER BANERJEE: It certainly could be a line which is leading to the pressurizer or something breaking off. That would be sufficient.

MEMBER APOSTOLAKIS: It would create debris of this magnitude and all of that, I mean?

MEMBER BLEY: If the relief valve created that kind of debris, George, that's a smaller hole than they're talking about here.

MEMBER BANERJEE: I think we should

separate these two issues right now. I think we should proceed to understand that this is a real problem, and let's not try --

MEMBER APOSTOLAKIS: -- design basis case.

CHAIRMAN SHACK: We need to understand regardless of what break size we're addressing. So if we could just keep going.

MR. SMITH: Okay. So we understand what a thin bed is. What we found is that the introduction order can have an effect on the amount of head loss. The amounts of debris need to be considered. The ratio of the fibrous debris to the particulate debris, and the debris sizing needs to be also considered. In general, we think the fine debris is more likely, again, to give you a higher head loss.

The other thing is that we do insure that all licensees perform within bed tests because we think that could be the most limiting test for a lot of plants.

The other thing that we saw issues with was test flume flow patterns. Some plants use stirring in order to keep the debris in suspension, to make sure that it all transports to the strainer, which we consider to be conservative. That's a good thing, but on the other hand, if you have to much turbulence created by the strainer, you can be washing debris off your strainer. Things like that can happen. So we have to be very careful of how we introduce the turbulence that keeps the debris in suspension.

There's other issues that we saw that the test plume didn't really model how the strainer is in the plant. Some strainers are down in sump pits. So they have a very confined space around them where some are laid out on the floor. So we had to take that into consideration.

And I think the point that I'm trying to make here is that we've looked pretty hard at the tests, and we've learned some lessons, and we've incorporated into the work we're doing.

Now, here is a --

MEMBER BANERJEE: I think you went over something quickly or not at all, which is the similarity to the previous slide, plant conditions, and I think the Committee should know that the Subcommittee had concerns about how that last bullet there could be sort of achieved because it's not very easy to have similitude, and one of the points Mike Corradini made at this meeting was that it might be worth looking at this at two different scales to see whether, in fact, scale had an effect or not in terms of the phenomena.

As far as we know, no real attempt to scale things at all have been done up to now; is that correct, Steve, or do you have some experiments that are different?

MR. SMITH: Well, we've seen a number of experiments done with various scaling. What we call scaling is the ratio of the test strainer to the size of the plant strainer basically based on area.

MEMBER BANERJEE: Yeah, we realize. We were talking with more hydrodynamic scaling because of this issue with settling and things which arose, if you recall, in the meeting. Strainers where you stir everything up, test them, there was no issue. Everybody felt this was likely to be conservative.

However, some designs it was necessary to take into account settling on the way to the strainer, and in fact, people were taking advantage of that in some way in their testing.

MR. SMITH: Yes.

MEMBER BANERJEE: And there was concern whether these tests were actually representative of what might happen in the plant, given that the scales in the plant are much larger, and therefore, could have phenomena which were --

MR. SMITH: I understand, and I think we were talking about Reynolds numbers and things like that, and what our position has been is that we have asked the vendors to create at least the same elasticities and turbulence levels, and I can't address, you know, anything --

MEMBER BANERJEE: That's fine. He suggested just stir it up as well and see if it works.

MR. SMITH: Right, right.

MEMBER BANERJEE: You know, that's the easiest way.

MR. SMITH: We have seen these tests that the last element end up with extremely high head losses. So we know that --

MEMBER BANERJEE: They have to do something else.

MR. SMITH: -- that transport is occurring in these tests. The other thing that we know about these tests is that the tests that allow transport, we've been somewhat stricter in the rules, you know, the way we allow them to introduce the debris into the strainer, into the test flume before it gets to the strainer. We've been somewhat more strict. We have a little bit stricter rules on chemical effects and how that particulate chemicals can settle and things like that.

MEMBER BANERJEE: How many plants are coming under this problem where they have to appeal to settling in order to get adequate performance?

MR. SMITH: I wouldn't characterize it as they have to do it. This is just the way that their strainer vendor is testing.

MEMBER BANERJEE: Right.

MR. SMITH: But I'd say probably 15 plants may be using this type. That's just a rough number. There's only two vendors that I'm aware of that use it and one vendor only does it sometimes.

MEMBER BANERJEE: Okay. Well, I think that's good enough. Let's move on.

MR. SMITH: Okay. We were looking at the picture. This is a picture of even though this debris was prepared as fine debris, it shows how it has agglomerated. Because they did not have enough water mixed in with the debris you have a big clump of debris and excessive settling of the debris can occur, and like we've said before, this when it goes into the flume is a big clump. It's less likely to get on the stringer and cause the conservative head loss.

MEMBER ARMIJO: Does that have any

aluminum in there? That looks all fibrous.

MR. SMITH: That's just fiber. That is basically Nukon, Nukon fiber.

I think we've got to go to the movie next.

The next one we're going to show you, this is a short movie. It's what we consider to be an appropriate debris addition, and you can see that when this debris goes in, it is going to basically be a cloud in the water. Some of you guys have seen this before.

And this also gives you an idea of what the test flume flow is like. The flow rate in this flume models what the flow rate would be in the plant. So you have an idea of what the flow rate is here, and you can see that this is very fine debris. This is what we consider will be the highest head loss on the strainer.

MEMBER BANERJEE: You didn't mention anything about chemical effects. I know there's another presentation, but obviously you're integrating some chemical effects in here, right?

MR. SMITH: Yeah. In general the chemical effects, first, the fibrous and particulate debris are added to the strainer. The chemical effects usually will not occur until later in the event. The corrosion has to take place. The chemical reactions have to take place, and then the worst chemical effects, which are the aluminum state, actually have to get the sump temperature down quite a bit before they come out of solution.

And I think Paul will discuss --

MEMBER BANERJEE: But in these tests, do you add surrogates in order to later in the test see what effects they would have?

MR. SMITH: In general, the surrogates are not added until later on. There is some testing, and Paul will go over the different types of testing that are done.

MEMBER BANERJEE: But is not part of this prototype tests the chemical effects?

MR. SMITH: After the particular in-fiber goes on the strainer, they have a head loss for that. Then they put the chemicals in.

MEMBER BANERJEE: So it's done in series.

MR. SMITH: Yes.

MEMBER CORRADINI: So just one question just to nail down the understanding. So the way these are designed is they try to maintain some given turbulence level as pre-predicted by some calculation and velocity.

MR. SMITH: For this particular test, only what is the same as the plant, as the strainer approach velocity. So the velocity at which it approaches the screen.

MEMBER CORRADINI: Yeah, I'm with you.

MR. SMITH: That's the only thing in this particular test because they don't allow settling. Now, if any debris settles, they stir it up. So it's going to get on the strainer.

MEMBER CORRADINI: Okay, all right. So it's strictly the approach velocity to the screen.

MR. SMITH: Yes.

MEMBER CORRADINI: Thank you.

MEMBER BANERJEE: Paul has a comment on the chemical test in particular.

MR. KLEIN: Paul Klein from NRR.

I just wanted to add one clarification. All of the tests that Steve's referring to have chemical addition at some point in the test. So the test that he describes all incorporate chemical effects one way or another.

MEMBER ARMIJO: In the picture, in the video, you showed three different editions. Are those three different types of debris? One, the fibrous first and then maybe the aluminum involved second?

MR. SMITH: It was two different types of debris and not all went in. They didn't want to put it all in the bucket at the same time. So they had to split it up, but, yes, first was the fibrous debris, and then comes the particulate debris, which it's a surrogate for paint basically coatings, and then third, other things that would be in --

MEMBER ARMIJO: And the aluminum or dissolved aluminum?

MR. SMITH: Yes, aluminum. Now, okay. Any aluminum paint would be in there, but then the dissolved aluminum components that are chemical effects, that comes later.

MEMBER ARMIJO: And that's a protocol that you endorse, to do it in that sequence?

MR. SMITH: Yes.

MEMBER ARMIJO: Okay.

MEMBER BANERJEE: I think that could also be CalSil or something, the particulate stuff, right?

MR. SMITH: Yes, it could be. In this particular case it wasn't, but yes.

MEMBER BANERJEE: It depends on the plant.

MR. SMITH: Yes. It could be CalSil, MicroTherm, NK, all of those bad things.

MEMBER BANERJEE: Okay. Let's go.

MEMBER ABDEL-KHALIK: Do the experiments scale the total inventory of the debris to the total inventory of water in the containment, the ratio between the two?

MR. SMITH: No. In general the debris and the testing is more concentrated because the volume ratio is much -- there's a lot more volume in the containment per debris than there is volume per debris. I mean, it's just too hard to build a test flume that big, you know, unless you put a really small strainer in there, which would create other issues.

MEMBER BANERJEE: Debris scaled to the strainer area. That's more --

MR. SMITH: The debris is scaled to the strainer area.

MEMBER BANERJEE: The volume of the water is not scaled to the strainer.

MR. SMITH: That's correct. In general, I would say that the volume of water is much lower. So you have more concentration of debris.

The head loss testing review guidance, this is something that we put out updated guidance in March of 2008. It has incorporated the lessons learned from our industry head loss testing that we talked about earlier. It is publicly available so that the vendors and the licensees can reference it when they're doing their testing and doing their evaluation of the data.

And we believe that tests and evaluations that are conducted in accordance with this guidance will end up with a conservative result for a strainer qualification.

On our path forward, we're going to look at plants that have RAIs, and they're going to have to provide acceptable responses, and this is going to require some additional analysis and may require additional testing for the plants. Some licensees that have had unacceptable results with their current or their most recent testing are now doing what we call -- they're coming in since they didn't pass. They're asking for an extension, and what we do at that point is we say we're asking them to test for success. That's our term, and what that means is they're going to test various plant configurations, debris loads, whatever it takes until they come up with an acceptable head loss for their strainer. Then they will know what modifications they need to make to the plant, and they'll go and do those, and that may require a modification, analytical changes, testing.

Different things for them to be able to show that their strainer will work.

And in the conclusions, we talked over all this stuff. We think that the testing methods have improved. Some licensees have demonstrated acceptable strainer performance. Some licensees have not and they're working to reduce their debris loads, and they may have to do some retesting, and some licensees are going to attempt to stand on the older test methods, and these licensees are going to get some RAIs, and we're just going to have to evaluate the RAIs, the answers to the RAIs as they come in.

MEMBER BANERJEE: So I have sort of a general comment to make about this. So if you look at these tests, they are quite conservative. So in the sense that they are going to give you the highest head losses, but they don't necessarily give you what is going downstream realistically because as I said, they are two screens in series here, and we're not testing these two screens together. Okay? We're testing one screen and they're going to test the other screen, which is the core.

So the conditions passing from one screen to the other, if you're conservative with the first screen, you might get less going to the core. So one has to be careful and keep this in mind because we revisit this point at the end of this discussion.

MR. KLEIN: Good morning. I'm Paul Klein from NRR.

I have four slides here to talk about chemical effects, and before I get started on those, which are pretty much a snapshot of where we are at this point, I thought I'd just spend a minute talking a little bit about where we were. I understand we don't have a lot of time, but initially a concern about chemical effects was raised by the ACRS in either late 2002 or early 2003. Because of that, there was some initial scoping studies done at LANL and then the ICET test series was started in around 2004-2005 time frame.

Those tests pretty much showed that under certain conditions some combinations of plant materials and buffers could cause certain chemical precipitates to form. Those tests really were to see if there could be an issue.

As a result of those tests, the NRC also sponsored some work at Argonne National Lab, and the focus of those tests were to try and evaluate the head loss consequences of these type of amorphous precipitates if they were to form in the post-LOCA environment.

So that work went on roughly in the 2005-2006 time frame. We saw that these products could cause significant head loss under the right set of conditions with a filtering debris bed, and that sort of led onto additional tests by industry, and that's what I'm primarily going to talk about today, is the work that industry is currently doing as well as some additional work that we've done at Argonne National Lab.

Next slide.

At this point, you know, industry has taken a number of different approaches to chemical effects testing. It's very vendor specific. There are predominantly three different methods that they use to generate precipitates in a test group. One is to use a Westinghouse topical report methodology that prepares precipitate outside the test loop. It's premixed, and then it's added to the test flume or test tank after the debris bed is established.

The second basic approach is to actually form precipitates in the test loop by chemical addition, and the third type that we call evolving chemistry is done one of two ways, either by putting all plant materials, including aluminum and metallic coupons in a 30-day test at temperature and at the appropriate pH levels, and the other is to form the debris bed within the long-term test, but then add the aluminum by metered additions of dissolved aluminum rather than using metallic coupons.

We have been very involved with the different vendors. We've observed tests at each of these sites, and we've had multiple interactions to try and understand their test procedures and to try and assure ourselves that each vendor has a conservative approach and that there has been review guidance that we've issued in September of last year. We also issued a safety evaluation on the basis industry WCAP topical report that talks about chemical effects.

Because it has been such a challenge, staff has also tried to bring in some additional technical expertise in the chemical effects area, and in addition to earlier work that was sponsored b the Office of Research, at LANL and ANL and also Southwest Research, we have more recently asked Argonne National Lab to perform some more NRR specific type tests to evaluate different pieces of some of these approaches, and we've also brought in additional expertise from a company that is named EMS, but in particular, their expert is Dr. Bob Litman, who has been in industry for a number of years and provides additional chemistry expertise.

Next slide.

Of the two major pieces that we've had Argonne evaluate within the last two years, one of them has been to try and compare the head losses from precipitates formed in a number of different ways, and so they've done that in their vertical head loss loop.

And we have in this slide a relative ranking of what we've seen. So we've used the WCAP methodology to generate their two different types of aluminum precipitates. We've also used the in situ formation by adding chemicals, and we also put in in one test or actually a couple of tests, aluminum coupons and elevated temperature, high pH conditions to corrode the aluminum and then use the temperature changes to cause precipitation.

And I think the key point that we want to show there in this slide is that the industry approaches tend to be more efficient at driving head loss compared to a version of the aluminum coupons. The bottom line there, the WCAP sodium aluminum silicate high purity water is really not relevant to industry test since they don't use high purity water for their type larger scale tests.

Next slide.

In addition to the head loss test, we have been asked to go on to perform a series of benchtop type tests to evaluate different parameters that we think may be important to chemical effects, and this slide here is trying to show a plot of different solubility type tests that have been done with aluminum. The solid symbols show tests where a precipitate was formed. The open symbols show tests where aluminum remained in solution and did not precipitate, and you can see on the slide that as you go to higher temperatures and also to higher pHs that favors the aluminum staying in solution.

What we're plotting is a term on the Y axis which is a combination of pH plus/minus the log of the aluminum concentration. To try and put it in a little better perspective, we tried to plot a pH of eight and 140 degrees where three different data points would show up on this plot. If you could hit that, this would be for concentrations of ten, 50, and 100 parts per million.

MEMBER BLEY: Are there thoughts that this kind of an idea might lead to some change in emergency procedures for cool-down?

MR. KLEIN: I guess the driver on trying to do this type of plot, we know from the WCAP methodology is very conservative because it assumes that all aluminum that is dissolved and goes into solution precipitates, and we know from a lot of the earlier tests that's just not reality. Some of it will remain in solution.

So we're trying to get an idea about for different plant specific conditions, you know, what would we expect to precipitate and what may stay in solution. So we eventually took this plot and put it into a more user friendly plot that shows solubility as a function of pH and temperature, and we'll use that to inform our reviews of individual plant licensee conditions.

MEMBER BLEY: Okay. Back to what I first asked you, do you know if any of the vendors are using this kind of information to adapt their LOCA procedures?

MR. KLEIN: I don't know that they're changing, say, the emergency operating procedures as a result of dissolution. I think some of the vendors recognize some of the conservatisms that are in the original WCAP methodology and they've adopted test approaches that might try to take advantage of this.

For example, in some of the longer, 30-day tests where they allowed the chemistry to evolve, in general they saw much less precipitate than they would have had to accommodate under a WCAP testing methodology.

MEMBER BANERJEE: These are all experiments, right?

MR. KLEIN: These are all experiments, correct.

MEMBER BANERJEE: What is the bottom line? Can you explain its significance?

MR. KLEIN: The two lines that were plotted here were just trying to show there might be a difference in behavior depending on temperature. So what we tried to do was develop a bounding solubility line that would accommodate all of the data points on here, including the couple of cases of aluminum coupons that seemed to be somewhat different than some of the other tests, and so the lines take into account the temperature.

We probably should have cropped the one more horizontal line to show a bounding type approach.

Next slide.

In summary, I'd just like to mention that we have been to all the vendor facilities. We have seen in general that the vertical head loss type tests are typically a lot more susceptible to chemical effects compared to the larger scale tests, and we think there's a number of reasons for that, not that I'm going into at this point.

Most of the plants that we have talked to and interacted with are using methods that are acceptable to the staff. There is one vendor approach that we recently concluded was not going to provide a conservative approach, and so there is one subset of licensees that are going to be on to a new testing methodology. From the tests that we have seen from both ANL and industry thus far, we think that the WCAP methodology is a very conservative methodology with respect to both the amount of precipitate that forms and that the properties of the precipitates that are used in that approach.

We plan on performing in the next few months a few chemical effect audits at licensees. You might be aware that the GSI team went out to about nine or ten plants and performed audits across the board. Our earlier audits were pretty much incomplete in chemical effects because they were in the process of testing. So the staff plans to go back to a few of the more interesting licensees and a variety of test methods and try to take a more complete look at how they do chemical effects.

MEMBER CORRADINI: I'm trying to understand what you just said, meaning that -- give me more detail of what you just said. You're going to go back and do what?

MR. KLEIN: We will go on site to a few licensees and try to look from the beginning to the end of their chemical effect evaluation to look at the assumptions that they've made.

MEMBER CORRADINI: Oh, to understand their analysis.

MR. KLEIN: Yeah, basically to understand their complete analysis.

MEMBER ABDEL-KHALIK: Is there a big picture metric that you use to rank plants with regard to the severity of chemical effects?

MR. KLEIN: One measure that's used if you use the chemical spreadsheet that's within the WCAP 16.530, that will predict the total amount of precipitate that's formed in that plant specific conditions, and that's a rough measure of, for example, how much chemical precipitate they might need to deal with.

MEMBER BANERJEE: Are any plants changing to sodium tetraborate or things like that?

MR. KLEIN: There's been, I think, about ten units that have done buffer changes and the most common one is the switch to sodium tetraborate. There has been other switches as well. Depending on the plant specific conditions, if there's a higher calcium load, they tend to switch from trisodium phosphate as a buffer.

MEMBER POWER: You're focused on the aluminum hydroxide, gibside (phonetic), boromite (phonetic) equilibria, which is always problematic because it's non-equilibrium and things like that. You don't seem to be paying much attention to the zinc hydroxycarbonate.

MEMBER BANERJEE: Question. We asked that.

MR. KLEIN: I think that's a true statement. Some of the ICET tests and some of the other tests that have been done at temperature and in the appropriate pH range have shown little zinc corrosion compared to aluminum.

MEMBER POWER: I mean, that's correct. The aluminum is much more sensitive in basic pH than the hydroxycarbonate, but it does form. I mean, I would think it would be of interest like in the 30-day test, but I certainly don't know.

MR. KLEIN: The ICET series had fairly low, which were 30-day tests, had fairly low zinc concentrations compared to some of the other materials that either corroded or leached out of insulation materials.

MEMBER POWER: I'm thinking that it is my perception, accurate or inaccurate, that many of the plants are using a zinc primer solely as their coatings for the steel liners, the primer in particular, AP-1000, but I think some of the existing plants also use just the zinc primer coating.

That gets you into a redox equilibria, the atmosphere. I mean a condensation draining down from the walls and things like that might load zinc carbonate more extensively.

MR. EWER: Matt Ewer from the staff.

In regards to coatings, there are some plants that have just the inorganic zinc primer as their coating. The majority are top coated with epoxy, and there are some just epoxy on steel systems.

So to say that the majority of the plants are just exposed zinc I think might be a little bit inaccurate, but they certainly are --

MEMBER POWER: I really didn't mean that.

MR. EWER: There certainly are some plants that have that situation.

MEMBER POWER: Yeah, I think there's some that use, like you say, just the primer. I mean, there are lots of reasons that you'd want to do that, and I'm just wondering if that would increase the hydroxycarbonate because the dissolution is actually occurring in an acid pH, and then it comes down to the sump where it's basic and precipitates.

MR. KLEIN: We did include zinc primed coupons in the ICET in both the submerged condition and in the atmospheric condition, and some of those tests did have initially lower pH spray before TSP was added.

MEMBER POWER: Covering it. That's good.

MEMBER BANERJEE: What was the pH of the spray?

MR. KLEIN: I think it depended on the ICET test, but some of the tests I know the buffer was added after a period of time. So there was pH I think that could have been as low as four and a half or five, I believe, for some period of time.

MEMBER BANERJEE: Well, you know, of course, all of the German experience with zinc, which came up as a question in the Subcommittee meeting.

MR. KLEIN: We are aware of the experience.

MEMBER BANERJEE: Yeah.

MR. EWER: One more comment in regards to the German experiment. It's our understanding that most of those corrosion products from zinc during the German experiments were just that. They were more of an erosion particulate zinc material, not necessarily a precipitate that came from zinc corroding, dissolving, and then forming some other material.

MEMBER BANERJEE: I didn't follow it exactly. So I don't know, but they told me that it came off the ladders and everything. I mean, wherever they had galvanized iron.

MR. EWER: Well, our understanding was that that experiment incorporated both flow and chemistry such that most of the material that was causing the head loss was pieces of galvanizing material that was actually eroding off when it was exposed to this high pH, and you know they're in an unbuffered situation as well. So that contributed to some of that.

But our understanding from meeting with them was that those were particulate material, not necessarily chemical products.

MR. KLEIN: I think, to add to Matt's comment, I think the other thing we looked at, there was a time effect with their data, and we concluded that we would not be at that low pH for the extended amount of time that they observed in that test before they did start to see appreciable zinc corrosion products.

MR. HARRISON: We'll move on to in-vessel downstream effects, and Steve Smith, again, will make a presentation on this topic.

MEMBER BANERJEE: We may want to get you back, Paul, to talk about in-vessel chemical effects. You're not escaping.

MR. SMITH: Steve Smith back again.

Okay. This is just what we're going to go over today. We're going to talk a little background on the downstream effects, debris in the core, and how it is modeled and testing; how debris loads for testing are determined; and then we have two sets of testing that we're looking at, and one is done. That's Diablo Canyon testing, and the PWR Owners Group is doing some testing over a little bit more wide range of conditions, and we'll talk about that. They're just getting started with that test program. Okay.

MEMBER BANERJEE: I see no pictures here, Steve. Can't you show us some nice pictures?

MR. SMITH: Yeah, we heard you might want to see some pictures. Donnie is going to be ready to give some pictures out here. When you want to see the pictures, let us know.

MEMBER CORRADINI: We're a very visual group.

MR. SMITH: Okay. WCAP 16.793 is the downstream in-vessel WCAP that was issued to provide guidance to the plants on in-vessel debris effects. That was presented in March to the Thermal Hydraulic Subcommittee and the ACRS raised some concerns with the adequacy of the WCAP and the methodologies and assumptions that went into that.

And the PWR Owners Group is now working to provide a more rigorous or a better guidance document. In order to do that, they started a program to test for potential head losses in the core, and they're also addressing some staff RAIs.

The testing that they're doing, they're using representative fuel inlet types. There are several inlet nozzle types used throughout the industry and varying debris loads, and when the WCAP is done, when the WCAP is completed, we're going to review it, and we're also going to keep track of the testing that goes on that the PWR Owners Group is doing.

MEMBER ARMIJO: Those are the various types of debris filters that the fuel manufacturers --

MR. SMITH: Yes.

MEMBER ARMIJO: There's several types.

MR. SMITH: Yes.

MEMBER ARMIJO: Areva stuff, Westinghouse stuff.

MR. SMITH: Areva, yeah. Areva has, I think, four different types, and Westinghouse has two plus a CE one, which is somewhat similar to theirs.

MEMBER ARMIJO: Right.

MR. SMITH: So the Westinghouse and the CE ones are relatively similar. The Areva ones are a little bit more wide ranging in the way that they work and the way they look.

MEMBER ARMIJO: Right. All of those have to be tested in this program or evaluated in some way?

MR. SMITH: Yes, they'll all be evaluated, and I think what the PWR Owners Group may do with a different inlet nozzle type, they have two separate programs, one for the Areva and one for the CE, Westinghouse, and they may try to determine which is the limiting -- which gives the limiting head loss when debris gets on it and then just test further with that.

MEMBER BANERJEE: But there's also the problem with the spacers and the grids as you go up, right?

MR. SMITH: Yes.

MEMBER BANERJEE: So those are also somewhat --

MR. SMITH: What we've seen is that the debris doesn't just collect on the inlet nozzle. It collects throughout on the grid spacers and whatever the flow diverters that they have to keep the water stirred up on the fuel. So, yeah, it all plays into the equation.

MEMBER BANERJEE: All sharp, sort of pointy things are very good fiber catchers.

MR. SMITH: Okay. Debris at the fuel inlet. The debris that gets to the core is a plant specific thing. It can include all of the debris that we've talked about already, fibrous insulation materials, coatings, chemical effects, all that has to be considered.

The fibrous debris that gets to the core is determined by testing that's done by the various strainer testers. They do bypass testing to determine how much fiber is going to get by their strainer.

MEMBER ARMIJO: These chemical, when they go through the core, you have all of that gamma radiation. Do they change in the dissolved or flocculated aluminum hydroxide?

MR. SMITH: I couldn't tell you. There's been --

MEMBER ARMIJO: Any testing that says, "Hey, look. If it goes through it's going to keep in solution or flocculated"?

MEMBER BANERJEE: That's why I said Paul doesn't get off the hook.

MR. SMITH: We'll let Paul.

MR. KLEIN: Okay. Paul Klein.

The effect of temperature has been pretty well characterized with these materials, but not the effects of radiation.

MEMBER POWER: Yeah, I can't think of anything more stable. I mean, if I had to run things into a radiation field and hope that they came out intact, that would be my choice.

MEMBER BANERJEE: But, Paul, there was a concern about reverse solubility, particularly with things like calcium, right? Can you address that?

MR. KLEIN: Yes. I think, you know, when we looked at some of the precipitates that could form, that calcium base could have retrograde solubility, which would encourage them to deposit on hotter areas. The aluminum base tend to be more likely to go into solution at elevated temperatures.

MEMBER BANERJEE: So what happens with plants where there is some high calcium loading?

MR. KLEIN: The LOCA DM model, i think, tries to deposit those according to the power density at given locations in areas where you have hotter conditions, where you might have boiling. You get more rapid deposition.

MEMBER BANERJEE: Well, that's barter (phonetic) fuel modeling effort.

MR. KLEIN: That's part of the owners group DM code.

MEMBER BANERJEE: Okay. Go ahead.

MR. SMITH: Okay. The fibrous debris that's used in the testing actually is not just what's used in strainer testing. It's representative of what would bypass a strainer. So what has bypassed a strainer has been looked at. We k now what the size distribution is, and that's what they assume gets to fuel when --

MEMBER BANERJEE: When you come back to this I have some concerns about this.

MR. SMITH: Okay.

MEMBER BANERJEE: But let's table it at the moment.

MR. SMITH: Okay. And the testing to date has assumed that there is no filtering occurring on the strainer, okay, because the debris has to go through the strainer, through the pump and then get into the core. So it's assuming that all of the particulate debris has made it through the strainer and all of the chemical debris has made it through the strainer, and that's a conservative assumption because we're basically assuming that all of that gets to both places.

And the chemical loading in the testing that has been done has been determined by the WCAP 16.530 that Paul discussed earlier.

Okay. The vendor fiber bypass testing on --

MEMBER BANERJEE: I wanted to qualify this for the Committee by saying that there's a certain size distribution which is assumed getting through.

MEMBER CORRADINI: But that is more, as you said, assumed. It is not calculated or estimated from other testing.

MEMBER BANERJEE: That's correct. So if you get longer fibers through, clearly, it has a very different effect from shorter fibers.

MEMBER CORRADINI: I just want to make sure. Is what I just said wrong or is that true?

MEMBER BANERJEE: What?

MEMBER CORRADINI: That there's an assumed distribution.

MEMBER BANERJEE: It's an assumed distribution.

MR. SMITH: The distribution that is created for the testing is based on fiber that has bypassed the strainers.

MEMBER CORRADINI: Oh, okay.

MR. SMITH: So we know basically what the size distribution that gets past the strainer is, and it's probably a little bit different depending on the strainer, but --

MEMBER BANERJEE: That's why I need to tell you about my strainer experiment later.

MEMBER MAYNARD: Well, it's my understanding in the strainer testing through the main strainer that they do not only CAP, but they also measure the size of the particles that are bypassing.

MR. SMITH: That's correct, yes.

MEMBER BANERJEE: Yeah, but it's after sort of recirculation. They call it a cumulative number, but I'll comment on that in a while because there's some issue there.

MEMBER MAYNARD: Do they take that at a couple of different stages or is it only after everything is done that they take what's left to measure?

MR. SMITH: All right. The next bullet, the downstream sampling methods, there's basically two ways that they get the downstream samples. Either they take a grab sample, you know, every once in a while or they set up a bag filter downstream and they catch everything. So that's the two different ways that they would collect the samples.

MEMBER BANERJEE: But I think his question is a germane one because are you sampling in time as you go down and looking at how the fiber size distribution is changing or are you just -- because the concern is always with the long fibers.

MR. SMITH: Okay. Well, I don't think that I have -- I'm not aware of anybody who does that. I'm aware that they do --

MEMBER BANERJEE: I'll tell you about my

two D-strainer experiment after this.

MR. SMITH: When you filter, when you're catching everything downstream, of course, you don't know when it got there. You're just catching everything. When you do the grab samples, you could possibly determine, you know. You could take and look at each one and say, you know, right after the event happened we got bigger through -- which is probably true.

CHAIRMAN SHACK: Yeah, but the question is whether you take the first grab sample before it recirculates. You take the first grab sample on the first pass-through.

PARTICIPANTS: Right.

CHAIRMAN SHACK: and that, I think, is the question.

MEMBER BANERJEE: And until you get long fibers through.

CHAIRMAN SHACK: Well, whatever you get you get, but you clearly need to make a grab sample before it recirculates in order to address that question.

MEMBER BANERJEE: You put your finger on exactly the issue.

MR. SMITH: And I think that there is grab samples that are taken on the first pass, and then generally what they do is they take them very frequently, maybe every minute or every two minutes, and then as time goes on, ten minutes, every hour, you know, just because there's so much less debris getting through.

CHAIRMAN SHACK: Well, I guess what we need is not so much what you think happens, but what does happen.

MR. SMITH: I see John coming over here to help me out.

MR. LENNING: This is John Lenning.

What Steve says is correct. There are some vendors that do that testing. I've seen results, I think, from PCI, is one, and ACL is another, and then there are some vendors that do a cumulative without time information.

CHAIRMAN SHACK: But if you've got a bag filter and it's truly cumulative, that's fine, but what you don't want is some guy running a grab sample on the third pass, on the seventh pass.

MR. LENNING: We understand that, and we look at that one.

MEMBER BANERJEE: Clearly, there are designs with low bypass of these.

MR. SMITH: they've got the steel wool in them basically to cut the bypass.

MEMBER BANERJEE: Okay.

MR. SMITH: Well, after they collect the debris, they dry it, and they weigh it to determine the mass, and then they determine the size distribution, and the PWR Owners Group is on the hook after our last Subcommittee meeting to get us some fiber bypass data, and we'll forward that to you guys once we get it.

Okay. The Diablo Canyon fuel testing.

MEMBER BANERJEE: Now you can show us some pictures, I think, after this.

MR. SMITH: Okay. See if we can get the pictures ready.

And I would say that you're correct in stating that you almost have two strainers or two filters there, and I think we've taken a lot of the lessons learned from our strainer testing and we've applied it to the test, and it's being done for the fuel inlet or further up the fuel blockage tube because it's not just the inlet.

The Diablo canyon testing, they did about 18 tests in various regions.

MEMBER ARMIJO: Could you enlarge that so we can see that?

MR. SMITH: You want to see the --

MEMBER BANERJEE: Yeah, and if the Committee wants, of course, we'll provide those beautiful slides.

MR. SMITH: Okay. This shows how the Diablo Canyon testing was done. There was testing that was done at CDI. Basically here's the mixing tank where all of the debris goes in at first. They have a pump here that pumps through a flow meter so that they know what the flow rate is. This is how they control the flow rate, and then it pumps up through.

Basically they had a very small test article, I would say. It was a normal cross-section, about eight by eight, and it had the bottom nozzle on it. It had the P-grid, protective grid on top of that, which sort of blocks, puts like cross patterns on the holes to keep anything big from going up through.

And then they had one intermediate grid, and that's all they had. So anything that got through that bottom nozzle and intermediate grid, it would cycle back around, and it would come back here. So we think they had a pretty conservative test. It collected probably a lot more debris in a smaller area than what happened if you had the debris collecting on a lot larger assembly.

MEMBER ARMIJO: And the flow rates, pressure drops, temperatures were what you would expect would exist in that region?

MR. SMITH: The temperatures were not. The temperatures were low because basically this is a piece of plexiglass so we could see what was going on, and that's how the testing is being done. Basically Lexan or plexiglass are building these things out of so that it's basically a room temperature test, you know. We're not testing at 200, 300 degrees.

MEMBER ARMIJO: So it would tend to be conservative in respect to keeping things precipitated and stuff like that.

MR. SMITH: Yes, for the aluminum based precipitous things, yes, it would definitely be --

MEMBER BANERJEE: But you are adding surrogates, right?

MR. SMITH: yes, yes. Surrogates were added to the test, but in the Diablo Canyon testing, they used basically the predicted debris for their plant. They're a relatively low fiber plant, and that's probably why it was such a small test article.

They were able to -- their tests actually came out with acceptable head --

MEMBER BANERJEE: They are a very low fiber plant.

MR. SMITH: Yeah, it's pretty low, yes.

MEMBER BROWN: Is that the orientation of the chamber, vertical? I mean, you're pumping stuff upwards?

MR. SMITH: Pumping upwards, yes, and --

MEMBER BROWN: How do you catch filter stuff? I pump stuff up. I've got a filter. I got on through. Why doesn't it fall back down?

MR. SMITH: It's done by the core.

MEMBER BROWN: Oh, you're checking a core approach.

MEMBER MAYNARD: This is a central fuel assembly.

MEMBER BROWN: Yeah, I didn't get that from your earlier discussion.

MEMBER BANERJEE: You see the picture there.

MR. SMITH: Here's a picture. Say, this would be like the vessel bottom here. Here's one fuel assembly out of the whole thing. The water is flowing up through here. Unfortunately you can't see the bottom nozzle, but this is the protective grid which sits right here, which sits right on the bottom nozzle, and this is the intermediate grid. So all of the debris got trapped in here.

MEMBER CORRADINI: These are four assemblies, four subassemblies?

MR. SMITH: It's just one.

MEMBER CORRADINI: Oh, this is one. Excuse me.

MEMBER BLEY: Say again where the debris ended up getting trapped.

MR. SMITH: Go down. We'll show.

Okay. This is clean. This is the bottom nozzle, clean before the test. This is the view from the top before the test, clean.

Okay. Here is the bottom nozzle. So you can see there was quite a bit of debris caught in the bottom nozzle holes.

MEMBER ARMIJO: It looks like the periphery more than the center part.

MEMBER BANERJEE: Yeah, but when you open it up, you see more.

MR. SMITH: Okay, and here's a view from the side. So you can see there was some debris around the external sides, too. Now you can see where there was debris that got through, and actually there was a lot of debris covering the entire protective grid.

MEMBER BANERJEE: That's why we only asked for a uniform calculation.

MEMBER BLEY: But with all of that debris we're seeing, you still have pretty good flow it sounded like. You didn't have any pressure drop.

MR. SMITH: They were usually in the range of inches of head loss. They did one test where they like doubled their CalSil and it went up to 70 inches, which is a pretty significant head loss, you know, maybe five feet of head loss, but with their expected debris, they were down around ten to 20 inches of head loss.

MEMBER BLEY: Is there any way that you know whether flow was blocked almost completely in some areas and not in others, or do we always get good mixing coming out of here?

MR. SMITH: You couldn't really tell. There was a lot of turbulence. You could see, you know, debris, you know.

MEMBER BANERJEE: You mean localized nucleate boiling could occur?

MEMBER BLEY: Something, something you're not planning on.

MEMBER BANERJEE: Yeah. I think probably not. I think this is -- in this case, this is low fiber plant. I mean, it's not a big deal. I mean, it's different if you're at a high fiber plant.

MR. SMITH: And the next thing we were going to talk about is the PWR Owners Group.

CHAIRMAN SHACK: With this low a fiber loading, you say they doubled the CalSil and it went through the roof then, I mean, from two to 70.

MR. SMITH: It made a significant increase in head loss, yes, by putting more CalSil, and they may have put more chemical precipitates in also. They did one test where they threw a lot of stuff at it.

MEMBER BANERJEE: Was that just atypical or was there some limiting scenario which they were testing?

MR. SMITH: You know, they were just trying to see sensitivity, is what they were doing.

MEMBER ABDEL-KHALIK: Were there always breakthrough holes?

MR. SMITH: Breakthrough holes, I don't --

MEMBER ARMIJO: That were unplugged. Was this uniform?

MR. SMITH: It was relatively uniform. I couldn't tell by looking at it if there was any, you know, particular channeling or bore holes or something like that.

MEMBER BANERJEE: They disassemble it.

MR. SMITH: Yes.

MEMBER BANERJEE: You do things which is very hard to -- you know.

MEMBER CORRADINI: So just if I can get a feeling for this, so the purpose of this test was just to get an idea of the delta P in the entry region of a typical assembly assuming you had uniform flow coming in.

MR. SMITH: That's correct. The assumption was uniform flow across all of the assembly.

MEMBER CORRADINI: So similar scaling is the approach philosophy. Here was what somebody somewhere calculated would have been the approach philosophy as I have the low pressure RHR or low pressure pumps going into recirc mode.

MR. SMITH: Right. Their approach philosophy was based on two different break cases. One was the cold leg and one was the hot leg.

MEMBER CORRADINI: Yeah, but it was the same logic.

MR. SMITH: Yes.

MEMBER CORRADINI: Okay, and the picking of the length was considered immaterial. You just wanted to get the initial inlet plate and a few inches of a mock assembly in just to create the screen effect?

MR. SMITH: I believe that when they first designed this experiment that they thought it would all collect on the protective grid, and they weren't thinking that a lot was going to collect on the intermediate grids, but what we've seen with the PWR Owners Group testing is that it collects throughout the assembly.

MEMBER CORRADINI: Well, that's not surprising.

MEMBER BANERJEE: They hadn't seen the German test which showed you that it goes through the inlet and hangs up on these.

CHAIRMAN SHACK: But since they recycle, it just keeps building up.

MEMBER CORRADINI: Okay, and so, again, I wasn't here for that part of the Subcommittee meeting. Did they sample the mixing tank as a function of time?

MR. SMITH: No.

MEMBER CORRADINI: Was anything sampled as a function of time, grab samples? I know you didn't coming into the flow, but I'm talking about the mixing tank, to look at the concentration of the stuff degrading as you're building up.

MR. SMITH: I don't think that they took any samples.

MEMBER CORRADINI: That's fine. Thank you.

MEMBER BANERJEE: Again, I want to warn you that everything is very, very sensitive to fiber length in these things. So if you've got long fibers, you get a very different --

MR. SMITH: What I should say about this testing, they actually took fiber that bypassed their strainer and they put the fiber in relatively slowly because they were trying to collect bypass. They didn't want to clog it up. So they probably had somewhat longer fibers, a higher percentage of longer fibers than what you would have, you know, eventually a fiber layer built in.

MEMBER BANERJEE: But they were taking the -- so let me get it clear. They were doing this two screen experiment almost realistically. They were taking typical fiber lengths as it was passing through and putting it in --

MR. SMITH: They were passing fibrous debris through a strainer, and then they would just collect that in a filter, and then they would take that and use it for this test for the fuel --

MEMBER BANERJEE: But was it as a function of time they were doing it?

MR. SMITH: They were just passing fiber through a strainer in order to get some to use in the test. They were --

MEMBER BANERJEE: The concern, I guess, is really this, that would long fibers pass through in the early stages and get caught in the core because the pressure losses are very much a function of fiber length. We know that. It has been done before for BWRs or whatever. I can probably dig it up.

Allian did some testing way back. So we know fiber length is very important in this exercise.

MR. SMITH: I think that if the fiber collects, I don't really know. I couldn't --

MEMBER BANERJEE: So the only question I think we're concerned about or might be is that if you do this in real time, but the screen maybe in the early stages long fibers are coming through and perhaps getting caught, and those could give you relatively high pressure losses compared to later stages when, you know, you've built up and only very short fibers are going through.

So let's just table it as a concern and let's move on.

MR. SMITH: Okay.

MEMBER ABDEL-KHALIK: What was the total duration of these experiments?

MR. SMITH: I would say they ran for three or four hours, maybe five, six. You know, it depended on the test, how long it took to stabilize and get all of the debris and things like that.

CHAIRMAN SHACK: But they ran until they stabilized.

MR. SMITH: They ran until they got to a certain -- you know, they had a limit on one percent in 30 minutes. I don't remember exactly what the limit of increase was.

MEMBER ARMIJO: What does "stabilize" mean?

MR. SMITH: Head loss, head loss rate of change.

MEMBER ARMIJO: Never got any worse.

MR. SMITH: I think a lot of these were still -- some of them were still --

MEMBER BANERJEE: Rising.

MR. SMITH: -- slowly when they turned the test off.

PARTICIPANT: I mean, this is a closed loop.

MEMBER ABDEL-KHALIK: So if you run this for an infinite period of time, all of the stuff will eventually deposit.

MR. SMITH: Eventually it will level out, but I mean, they had a curve that was, you know, exponential type.

MEMBER ABDEL-KHALIK: Yeah, will never level off.

MR. SMITH: Well, once all the debris is taken out of the system it may level. I mean, in head loss testing we've seen where they do eventually really level out.

MEMBER BANERJEE: But these were still rising as I recall, right?

MR. SMITH: Yes, these were still rising. Some of these were still rising when they terminated them. The thing about this test is that after a certain amount of time they're going to go into hot leg recirc, and it's going to reverse the flow through the core.

MEMBER CORRADINI: So do you have a -- I'm sorry. I'm sorry, Sam. Excuse me.

MEMBER ARMIJO: No, go ahead.

MEMBER CORRADINI: Is there a typical plot of head loss as a function of time? I mean, to get your idea of stabilization, it's coming up and it's hanging up, increasing, but the rate of increase is decreasing. Is there an example somewhere that you showed?

MR. SMITH: You can get that from -- I mean, we have that information from them.

MEMBER CORRADINI: That's fine. That's fine. If you've got it, later is fine.

MEMBER BANERJEE: Please.

MR. SMITH: We're going to talk about the PWR Owners Group testing now. The PWR Owners Group has just started their testing. The last I knew they had two tests done. We saw the second test that was run up there a couple of week ago.

What they used for their test was the standard P grid which seems to be a little bit more able to create a little higher head loss than the alternate P grid because Diablo Canyon actually did both. They did a little test to see which one was worse for head loss.

Their testing is using the hot leg flow

rate, and that's 44 gpm per assembly, typical for I guess they're using a Westinghouse four loop reactor as their model, and that's a little bit higher. Forty-one gpm is what they used for Diablo Canyon.

MEMBER BANERJEE: But they're not doing a cold leg then.

MR. SMITH: The cold leg flow rate is much lower.

MEMBER BANERJEE: Will they be doing that?

MR. SMITH: They may have to do that, but right now the plan, the last I understood it -- and Mo can correct me if I'm wrong -- was to use the hot leg flow rate, and if they could get acceptable results with the hot leg flow rate, they would apply the cold leg acceptance criteria.

MEMBER BANERJEE: But the Diablo Canyon did both, right?

MR. SMITH: Diablo Canyon did both, yes.

MEMBER BANERJEE: And I think later on calculations were done for the cold leg break, right?

MR. SMITH: I don't remember.

MEMBER BANERJEE: Yeah.

MR. SMITH: Cold leg, he may have done both. He may have done both.

MEMBER BANERJEE: I remember the cold leg break.

CHAIRMAN SHACK: He represented the cold leg.

MEMBER BANERJEE: He represented the cold leg.

MR. SMITH: He did do the cold leg. That's for sure because I remember we were talking about the acceptance criteria for the two different valuations.

Basically what we saw up there at the Westinghouse testing or at the testing that was conducted at Westinghouse is that we think that the protocol they're using can create conservative results. What they're doing, what their plans are is that they're going to test, as we discussed a little while ago, they're going to test; the PWR Owners Group will test all of the fuel inlet assemblies. They haven't started any Areva testing yet, and I think that one might be a little bit more interesting as far as the actual bottom blockage because I think the openings are somewhat smaller on the Areva fuel inlets.

And then they plan to increase their debris loads to see how many plants they can actually bound. So they're going to increase the fibrous load, the particulate load, the chemical loads, and they're going to see how many plants they can bound with the testing.

And we're going to continue to look at the data and look at their test results as it becomes available, and like we talked about, the PWR Owners Group is going to try to limit the -- we're going to go back and look at what the limiting head losses, allowable head losses are for the cold leg breaks and the hot leg breaks.

MEMBER BANERJEE: I think now that you have these nice TRACE calculations done by RES, it would be worth feeding that information back.

MR. SMITH: Yeah, and that's something we're going to look at. We're going to look at the trace calcs. We're going to look at the PWR Owners Group calculation, and you know, we'll get a few other inputs probably, too, because it's pretty important to get this right.

And the conclusions in this is that Westinghouse in CE fuel testing is underway. Areva testing will be done later. It's supposed to start later in the year. The testing is going to determine what the allowable debris loads are for various fuel designs, and plants will use that to determine, you know, whether their loads are acceptable.

If it's not, they're going to have to do some additional evaluation or modification to their plant, and WCAP 16.793 will be revised based on the test results and other questions that we've asked.

MEMBER CORRADINI: And so they're going to be looking at what is deposited initially? When you say "testing to determine acceptable debris loading," can you tell me more about what debris loading means?

MR. SMITH: Well, I think we still have the question that we talked about about the fibrous debris sizing, but the debris loading is a plant specific thing. So every plant has done an evaluation to determine how much chemical effects we're going to have, how much particulate debris they're going to have and how much fiber is going to be generated in a plant.

So I guess there's particulate coatings debris. All of that has to be looked at, and what they're going to do is they're going to try to test with maximum amounts of those debris to bound the plants.

MEMBER CORRADINI: Right, but let me ask it a little bit differently because maybe you've answered it and I just don't -- so they're going to have some characteristic debris loading that is specific to their plant, their break, their zone of influence, and their screen.

MR. SMITH: Yes.

MEMBER CORRADINI: And then something passes through, and then so that's your source term, so to speak.

MR. SMITH: Yes.

MEMBER CORRADINI: So given that source term, what are they going to measure to determine how much gets caught up so that you can actually look representative from plant to plant?

In other words, if the source term has so much chemical and so much fiber and so much little stuff and so much big stuff and they run the test, what are they going to look at to decide that it was good, bad or indifferent? Only delta P?

MR. SMITH: Head loss, and that will also be dependent on the fuel design, the fuel characteristic.

MEMBER CORRADINI: So the assumption is if they know head loss and they compute that into some sort of thermal hydraulic calculation, they will then do a calculation to see that they get adequate cooling, given the additional --

MEMBER BANERJEE: This is coming.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: If you just wait.

MEMBER CORRADINI: Okay. Sorry. Thank you.

MEMBER ARMIJO: But that's kind of a gross measurement, but are they going to look at the localized --

MEMBER CORRADINI: I don't think they can.

MEMBER ARMIJO: -- spatial, you know, accumulation around a spacer over a fuel rod causing localized damage, that part of the analysis?

MR. SMITH: That's part of the analysis that's not part of this particular part of the analysis.

MEMBER BANERJEE: I guess there's a good question related to this though. I mean, just looking at the fact that you don't want to uncover the core, but in this situation you're going to have many fuel failures anywhere, so you get local fuel failures, are you going to worry about this or are you just going to worry about core uncovery? That's really the issue.

MR. DINGLER: This is Mo Dingler with the Owners Group.

What we're talking about here is only one aspect. There's four other aspects. As Paul Klein says, we develop a DM LOCA, which is there to define how much debris. We assume all of the chemical, all of the calcium in that and power distribution is sorted onto the fuel assembly. That's one part of the aspect.

We also evaluated local hot spots and see if we maintain that, as you're saying, collect one location. We assume 50 mLs, and it's less than 800 degrees. So the blockage that we're talking about, that Steve and them were talking about is only one aspect of four others that we looked at the total integral.

We did COBRA tracking, the same as what is going to be talked about on TRACE code to show that you've got so much blockage you still have adequate floor or core cooling.

So you put it all together. At the end we're only talking, again, one aspect of many to do the whole thing.

MEMBER CORRADINI: So can I ask a question here?

MEMBER ARMIJO: Ultimately we'll get to see some of those analyses.

MR. DINGLER: You'll be able to see all of it, yes.

MEMBER BANERJEE: And you can ask a question, but we're going to have to move on.

MEMBER CORRADINI: Okay. Then I'll wait. I'll wait.

MR. HARRISON: At this point I'll have Ralph Landry come up and present. Bill Crutiak is not available today to present for Research. So Ralph was gracious enough to step in and present on this.

MEMBER BANERJEE: Head in the lion's mouth.

MR. LANDRY: Foolish enough to come up here.

Okay. To put this analysis into perspective, back in march when we appeared with the Thermal Hydraulic Subcommittee, the staff presented some analyses which we had performed with TRACE, and the Owners Group presented analyses which they had performed with WCOBRA TRAC.

The purpose of those analyses was to determine what the level of core inlet blockage could you sustain and still maintain enough coolant flow into the core to match the boil-off.

We found with the TRACE analyses that we could take a 95 percent core inlet blockage and still have adequate cooling for the core. That blockage though was taken as one little area, by only five percent of the core inlet. Now, the core model that we have is 16 cells, 14 cells high.

So out of those 16 cells, we enough of them blocked so that only five percent area slot was still available for core inlet cooling. The Owners Group had something like a 90 percent blockage that they said they could -- their calculations showed they could take.

With that five percent available inlet area we only got a 300 degree Fahrenheit increase in core temperature. The Committee raised or the Subcommittee raised a number of questions at that point as to the realism of the calculation. Since we were blocking off 95 percent of the area, their concern was do we get jetting coming in or do we get that kind of a spread of a fluid that TRACE was predicting so that the fluid was spread through all of the core rather than just jet and go up in a plume through the center of the core.

Following that meeting, we went back to cohorts in the Office of Research and we said, "Well, let's try something. Let's try taking those 16 nodes, 16 volumes at the core inlet, and let's put a five percent area on each one of those instead of one big five percent area so that we're distributing the area."

We did that calculation, and the temperature was within four degrees of the temperature we had previously calculated. Cohorts in the Office of Research said, "Well, why don't we try something with TRACE? TRACE has the ability to model a porous medium. So let's model the inlet of the core as a porous medium rather than a restricted opening."

So Research decided they would do a porous medium so that you have a head loss over the entire area of the core rather than a simple five percent opening in each cell, and then since we had not performed a lot of the analyses of this nature, they decided they were going to do a hand calc.

I put "hand calc" in quotes because actually it was a calculation using an Excel spreadsheet.

Now, the way the core inlet was modeled as a porous medium was to take data which we had from PNNL tests that were reported in NUREG CR-6917 and NUREG 1862, test data that were taken using Nukon and CalSil debris bed material.

That material was then used to model a

pressure drop, porous medium for the entire inlet of the core.

Now, keep in mind as you've heard all of these discussions so far, they have talked about particulate and all of this other material and chemicals. Those were not considered in this analysis. This was restricted to Nukon, which is fiberglass, and to CalSil because the data that were taken in support of those NUREG reports did n ot take marinite, dirt, paint chips, chemicals, all the other material, and we decided very deliberately that we were going to restrict the porous medium pressure drop to where we had data only. We're not going to try to project into what would be a pressure drop, where we did not have data to support that decision.

Now, you've heard a number of comments already this morning, and Steve talked about it in his first presentation that the volume of debris, whether there's ratio in the fiberglass to particulate can make a huge difference in pressure drop. So we did not want to depart from where we had hard data.

That determination came out with a delta P for the bed as being a function of the bed thickness and the approach philosophy of the fluid. We modeled four cases, the unbroken or unblocked case, and then

1.2, 2.4 and 4.8 inches of debris.

MEMBER CORRADINI: And those numbers were arrived at?

MR. LANDRY: Those were --

MEMBER BANERJEE: Parametric.

MR. LANDRY: Right. It was just parametric numbers to see. This was to determine could we get to a point where this debris bed, this porous bed would get to the point that it would sufficiently slow down the flow, that we could start to see a core heat-up.

MEMBER BANERJEE: You were just looking for core uncovery.

MR. LANDRY: Right. This was not to be a definitive analysis of how thick the debris bed on a core inlet can be. This was to determine could we model a distributed flow into the core. Could we model a restriction sufficient to cause core --

MEMBER BANERJEE: Yes. Mike, to give you back ground, the Subcommittee asked for a uniform bed to be formed and to find what pressure loss across that bed could lead to core uncovery, and that's really what they're trying to answer with this. It's a straightforward question.

MR. LANDRY: Now, this plot is of the

collapsed liquid level in the core, and you can see the bottom of the core, the top of the core, and the figure in black is the point -- is the collapsed liquid level in the core up to the point that we initiate recirculation.

We assume that recirculation would begin at 1,200 seconds, which is just the arbitrary point that we set.

MEMBER BANERJEE: This is the cold leg break.

MR. LANDRY: Yeah, this is cold leg. This was just we said 1,200 seconds. Okay. At this point we're going to initiate the recirculation.

This is when it's easier to use a pointer.

The red curve shows the collapsed liquid level in the core when there is no blockage. The other two curves, the blue, green and brown show the effect of blockage.

Now, you see a big dip at 1,200 seconds when we initiate the blockage. That's because we initiated the entire blockage instantaneously at 1,200 seconds. As you saw in the material that Steve was just presenting, the test data all show that the blockage builds up over time.

So you don't instantaneously have a 4.8

inch block at the inlet of the core. This is going to build up over hours. Instead, because of the way we had to model with the code, we assumed the entire blockage occurred instantaneously. So --

MEMBER CORRADINI: So the core doesn't uncover. It just gets shorter, water logged.

MR. LANDRY: Well, the collapsed liquid level.

MEMBER BANERJEE: That's the collapse. He hasn't shown us the temperature.

MR. LANDRY: You still have two phase flow in the other half, and tests that have been done, Thetis test and RDHT test, show that you can have liquid to the top of the core, two phase liquid. You don't uncover the core. As long as you have a collapsed liquid level that's at least 50 percent or above.

MEMBER BROWN: Right. If you get below 50 percent is when you get core uncovery.

MR. LANDRY: yes.

MEMBER BANERJEE: So you get core uncovery.

MEMBER BROWN: Fifty percent of the core height.

MEMBER BANERJEE: At that level you get

core uncovery.

MR. LANDRY: If we could just go to the next one, now this plot shows the PCT, and you can see that the temperature drops. This is in Kelvin. In real units that would be -- 1,400 is about 2,050, 2,060 degrees, and the 400 degree is a little under 300 in Fahrenheit. It's around, I think, 263 --

MEMBER CORRADINI: The magical temperature to worry about is 1,500 K.

MEMBER BANERJEE: No, it's 800.

MR. LANDRY: Well, 1,473 is 2,200 K.

MEMBER CORRADINI: Heat clad temperature, yeah.

MEMBER BANERJEE: Yeah, but this, for boil-off it's not Appendix K remember.

MEMBER CORRADINI: I understand.

MR. LANDRY: I will get to that, Sanjoy, but thanks for the lead-in.

MEMBER BANERJEE: Okay.

MR. LANDRY: You can see, if I can get the mouse pointer back, that 1,200 seconds is when we initiate the blockage and three of the colors stay right on the curve where they had been. They don't show any increase in temperature.

The one case, the 4.8 inch blockage case, shows an increase in temperature that goes up to about 900, 950 degrees Fahrenheit. We have set an arbitrary limit in these recirculation mode heat-ups of 800 degrees Fahrenheit. We're not allowing a limit of 2,200 as 50.46 allows, the acceptance criteria. We've set the limit at 800 Fahrenheit because the zirconium alloy cladding materials that have been heated to a high temperature -- temperature is on the order of 2,000 and above -- cooled and then reheated have only had data taken for a reheat to 800 degrees Fahrenheit and still show that they maintain integrity.

MEMBER CORRADINI: So after that point it's not clear.

MR. LANDRY: We don't know. They may.

MEMBER CORRADINI: But you don't know.

MR. LANDRY: There are only data in existence for mutual heat-up, quench, and reheat to 800 Fahrenheit. So --

MEMBER BANERJEE: And the Germans don't allow any increase.

MR. LANDRY: So this is why we have said a reheat temperature limit of 800 degrees Fahrenheit is being imposed because there are no data beyond that point.

Now, if the industry wants to say they can go back to 2,200 --

MEMBER CORRADINI: That's fine. I understand.

MR. LANDRY: -- fine. Go get the data.

MEMBER CORRADINI: Okay. I see.

MR. LANDRY: But since Sanjoy gave me the lead-in, this is the explanation of why we're saying 800. In this case the prediction is it goes to 950, but so that we could say somewhere in this range with this kind of debris bed, Nukon/Calsil only, somewhere between 2.4 and 4.8 inches we would expect to see the heat-up begin.

CHAIRMAN SHACK: But we really need to calculate that.

MEMBER ARMIJO: Did you say temperature in Kelvin?

MEMBER BANERJEE: Let's take one question at a time.

MEMBER CORRADINI: I'm sorry.

MEMBER ARMIJO: What's that temperature in Kelvin that you're trying to say it's a limit?

MEMBER CORRADINI: It's there.

MR. LANDRY: Eight hundred Fahrenheit.

MEMBER ARMIJO: Okay.

MR. LANDRY: And this goes up to 800

Kelvin, which is about 950 Fahrenheit. So 800 --

MEMBER ARMIJO: Eight hundred Fahrenheit is --

CHAIRMAN SHACK: Yeah, it's the head loss you really need to look at here to compare with the experiments because you don't really know what the real beds are going to -- we're not going to see a CalSil/Nukon four inch bed, but we'll measure a head loss. So this is what head loss are we talking about for this bed?

MR. LANDRY: I don't have the--

MEMBER BANERJEE: If I recall the numbers, it's between 2.4 and four psi.

CHAIRMAN SHACK: So you can tolerate about that much.

MEMBER BANERJEE: Somewhere between 2.4 and four.

CHAIRMAN SHACK: For the cold leg break.

MEMBER BANERJEE: The hand calculations, if I remember, my memory, showed about four, and that TRACE was somewhere between 2.4 and four, but we can verify that later on.

MEMBER ABDEL-KHALIK: When the code was re-initialized, that 1,200, what parameters, what kept the same? All parameters?

MR. LANDRY: Except for the resistance --

MEMBER ABDEL-KHALIK: For the geometry?

MR. LANDRY: Except for the resistance, yeah, but geometrically it was the same. What was changed was the resistance at the core inlet.

MEMBER ABDEL-KHALIK: At the core inlet.

MR. LANDRY: So the flows stayed the same, and then the flows suddenly saw a step increase in resistance, and that's why you saw that sudden drop in core collapsed liquid level, because the flow coming into the bottom of the core suddenly saw an increase in resistance.

MEMBER ABDEL-KHALIK: So you just added a loss coefficient at the inlet.

MR. LANDRY: It was just a porous medium loss coefficient.

MEMBER CORRADINI: Porous medium loss coefficient. Just a K.

MR. LANDRY: Essentially, yeah.

MEMBER CORRADINI: Okay.

MR. LANDRY: Now, this is calculating. The behavior of porous media is quite complicated. There has been a lot of work done n this over the years. Since back in the '30s porous media have been studied. But there's a paper that just came out in the Nuclear Engineering and Design Journal over the summer written by a group in Germany in which they looked at compressibility of porous media on strainers. It's part of the strainers, the stuff Steve was talking about, but the implications are the same here.

And that is that while the work that we've been doing is using the Darsey Law, in reality when you start talking about these compressible media, the Darsey Law does not apply. This is no longer a linear -- the delta P is no longer a linear function of the approach philosophy, but it's good enough for this case because in this case we wanted to determine could we find a point at which we could restrict the flow enough to cause a heat-up.

MEMBER CORRADINI: So a squishy bed versus a rigid bed.

MR. LANDRY: It becomes even more complicated because work that was done back in the '30s has been shown that it was based on granularity, a granular bed, and today with the fibrous beds that are much more squishy, the work that was done with granularity does not apply to the bed that's compressible with fibers.

But what we have is a bed that is both.

When we look at the fiber being captured, the particulate being captured, you're talking about a granular substance and a fibrous substance together, and then you have the chemical.

So --

MEMBER BANERJEE: Is it true that what you --

MR. LANDRY: -- concerning the properties, they may be very, very much more complex than we've taken it.

MEMBER BANERJEE: Yeah, yeah. What you really used here was the Crutiak had developed a model which fitted the data, and he basically programmed that model, right?

MR. LANDRY: That's right. That's why I said this is very specific to the Nukon/CalSil.

MEMBER BANERJEE: To that specific bed.

MEMBER BANERJEE: But the first approximation is the pressure losses are what really matter. I mean, yes, it's true that the behavior is more or less linear with bed thickness, pressure loss in terms of velocity, but it's the pressure loss that really matters, and was it between 2.4 and four psi? Can you check that?

MR. BAJOREK: I can check, but I think

that's about correct. Let me just clarify what we actually did.

TRACE doesn't have a real porous media pressure loss correlation. What Phil did is he went back to the -- the data had been taken at LANL, and we fitted curves to give us a loss coefficient K equal to an A over V to a B that fitted the experimental data. We took that correlation and for that specific location in the TRACE model. We made the code use that loss coefficient.

So as we turned on the debris at 1,200 seconds, instantaneously forming, as that velocity changed with time, the K would adjust itself.

MEMBER BANERJEE: That's because your K is a function of V in this case because it's more or less linear, but let's not get into the argument right now. So it's fine. I've looked at this, and I'm quite happy with it. Okay?

MEMBER MAYNARD: What's the significance of the drop in temperature at the tail end? Just ending the program or is there something physically going on that the temperature is dropping?

MR. LANDRY: It's requenching. There's sufficient flow to bring the quench front back up and bring -- the collapsed liquid level is coming back up, and the core temperature is coming back down.

MEMBER BANERJEE: The thing of the time constant because of the way the velocity is varying with it and you get more flows. Anyway, that's fine.

MEMBER MAYNARD: I will just stop there. I wanted to make sure.

MEMBER BANERJEE: I think we probably need to.

MR. LANDRY: Okay. I'll do it real quick now.

The hand calc model is really simply a balance of heads and losses, and this was done as a part of a spreadsheet at two points, at the 1,200 second point and at a 2,000 second point, and it was done for the unblocked case and the 4.8 inch thickness case.

And this is taking the plot that I showed earlier of the collapsed liquid level. I'm taking out the 1.2 and 2.4 inch thick beds and just showing the unblocked case and the 4.8 inch block case. This is simply to show that the hand calc shows with the red diamonds for the unblocked and the brown triangles for the 4.8 inch block, that the hand calc solution is giving collapsed liquid levels within the bounds that were calculated by TRACE.

The purpose of this was not to get a definitive analysis of the collapsed liquid level, but simply as a sanity check. Since we're doing something different with TRACE, let's do a simple hand calc and use this as a sanity check to say do we believe what TRACE is giving us, and when we look at this we say, yeah, the hand calc numbers are coming in in the range that we're seeing with the code calc. So it gives us a much better feeling for what we're seeing with the code.

MEMBER BANERJEE: Yeah, the hand calc is with homogeneous. So it will be a little different. TRACE has got that behavior because you've got fluoridium transitions.

Okay, Ralph. Thank you. Very interesting.

MR. HARRISON: And I'll just say in conclusion that through the presentations hopefully today you see that the staff has established a process for being able to close the generic letter, recognize licensees as significantly increased their -- made significant modifications to prevent unacceptable strain velocity that reached their strainers, but the staff has developed guidance to insure there's conservative test profiles and evaluations, and just recognize that the in-vessel downstream effects portion of our review will be addressed through our review of the WCAP 16793.

So with that I --

MEMBER BANERJEE: Thanks, Donnie. I think you've done a great job and progress is being made. So you'll be available, of course, when we write the letters to interact with us.

MEMBER CORRADINI: One thing I forgot to ask Ralph, but I just did a calculation. You said two to four psi was the equivalent delta P.

MEMBER BANERJEE: They're going to check it. Steve will get back to us on that.

MEMBER CORRADINI: Okay. I was going to ask about one or two meters -- that's about one or two meters head height of water. So it's a very big delta P.

MEMBER BANERJEE: Let's get back with those numbers and then we can discuss it.

So when we start to write the letter or even before that, we'll have access to that information.

MEMBER ABDEL-KHALIK: It was also the inconsistency between the industry calculation of the delta P and the staff's calculation.

MEMBER BANERJEE: Well, there is no comparison. Staff has used TRACE. I mean, you know, let's not worry --

MEMBER CORRADINI: They did a hand calculation though. That I like.

MEMBER BANERJEE: Well, I think it's always good to do a sanity check.

MEMBER ABDEL-KHALIK: So the industry calculation was a bounding calculation the way you would expect the delta P to be for a cold leg break and a hot leg break,a nd I think it would be important to sort of reconcile these two numbers.

MEMBER BANERJEE: Well, the industry, if you recall, had a void fraction assumption in the core, whereas this does avoid the fraction calculation in the core.

MEMBER ABDEL-KHALIK: But it is 50 percent.

MR. DINGLER: Yeah, this is Mo Dingler.

MEMBER BANERJEE: But it's less than --

MR. DINGLER: In talking to Bill afterwards, he had pipes, about 4.8, I believe. We took and divided the -- took out the head loss through the core, which was 1.7. So if you take out his 4.8 and put 1.7, we're at about 2.5. So we're about the same thing. So we were comparing apples and oranges in that presentation because he had total psi, and we separated the loss through the core, and that's how.

We talked to Bill afterwards, and we're still checking the numbers, but initially that's what we came away with on that. So there really wasn't discrepancy. It was just how it was presented.

MEMBER BANERJEE: Anyway, let's not worry about that right now. We have gone over TRACE with a sufficiently fine tooth comb that we would want to believe that it produces, whatever anybody else does.

Any other questions? Can we wrap it up now?

I think the staff will be available when we write the letter. So if anything arises, we can interact with them. So I'm going to hand it back to you and thank you for a nice presentation.

VICE CHAIRMAN BONACA: I guess I'm going to recess for lunch.

(Whereupon, at 12:27 p.m., the meeting was recessed for lunch, to reconvene at 1:30 p.m., the same day.)

CHAIRMAN SHACK: I would like to come back into session. Our next topic will be selected chapters of the SER associated with the economic simplified boiling water reactor design certification application. And Mike will be leading us through this discussion.

MEMBER CORRADINI: Okay. Thank you, Mr. Chair. So welcome back, everybody. I'm sure you remember this. This is like deja vu. We just keep on -- so we're on to now Chapters 19 and 22. If you remember that we are doing kind of a continuing look at the SERs as the chapters are produced.

This, in particularly, the topic today will be the PRA and severe accident management. We had a subcommittee meeting on June 3rd, and then a subsequent subcommittee meeting on August 21st and 22nd, where GEH and the staff spoke to us about their open items, the staff spoke to us about their open items, and GEH explained specifics relative to the PRA and their severe accident management work.

I don't really have much more to say, other than I think we've converged, approaching some current views on this. And so we asked the staff and GEH to come today to kind of give us where they are relative to Chapters 19 and 22. And I'll first turn it over to Hossein Hamzehee --

MR. HAMZEHEE: Yes.

MEMBER CORRADINI: -- who will introduce

the players in the game.

MR. HAMZEHEE: Thank you, Mike. Again, I am Hossein Hamzehee, the Chief of the PRA Branch in the Office of New Reactors. And I am mainly responsible for the ABWR and ESBWR designs. And as Mike mentioned, we had already made two presentations in the last few months, and we are here today to present a summary of those two presentations.

And I would also like to take advantage of this presentation and mention to you that we, as part of our review efforts, we planned two site visits in order to get a little more familiar with the GEH PRA models and some of the details. The first one we completed late last year, and we have a second one, which is -- we are planning to perform the second site visit around November/December of this year. And as part of that review, we also plan to cover those areas that were identified by the SER Rev subcommittee members at the August meeting.

And I would also like to mention that we did also go to the BiMAC test area in Santa Barbara, California, in August of 2007, and observed some of the testing of that.

MEMBER CORRADINI: Not the beach.

(Laughter.)

MR. HAMZEHEE: Very close. Very close, but not the beach.

MEMBER CORRADINI: Just checking.

MEMBER BANERJEE: Where is this exactly?

(Laughter.)

MR. HAMZEHEE: Oh, stop it. Just --

(Laughter.)

MEMBER STETKAR: Because I have lost the timeline on the revs of the PRA, this that you made last year, was that Rev 2?

MR. HAMZEHEE: The first site visit that we did on Rev 2.

MEMBER STETKAR: Was 2.

MR. HAMZEHEE: Yes.

MEMBER STETKAR: All right. Thanks.

MR. HAMZEHEE: Before we wrote our preliminary SER.

MEMBER STETKAR: Okay.

MR. HAMZEHEE: Now, before we write the final SER, we would like to perform the second site visit review, and also cover the areas that you brought up at your last meeting.

MEMBER STETKAR: Thank you.

MR. HAMZEHEE: And with that, I would like -- what we plan to do is first turn to GEH, let them present the status of their PRAs, and then we will have the NRC staff to get up there and talk about the status of our reviews. With that, I turn it to Rick.

MEMBER CORRADINI: Mr. Wachowiak, you're going to be presenter and manipulator of the computer?

MR. WACHOWIAK: Presenter, manipulator, and I have a laser pointer if I need it.

(Laughter.)

MEMBER BLEY: If you use the mouse, we can see it on all the screens.

MEMBER CORRADINI: But it sometimes doesn't work, so have a backup for --

MR. WACHOWIAK: Okay. So to introduce myself again, Rick Wachowiak from GEH. And as we said, I'll be presenting the ESBWR PRA and severe accidents, and then we'll get into the regulatory treatment of non-safety systems at the end.

The organization of my presentation today is that I'm going to talk about what it is we are -- that we are certifying, and what the SER is about. We'll then transition into a summary of where we are on the ESBWR review, an overview of the meet -- then an overview of the meetings that we had with the subcommittee over the past approximately several months. We've had several meetings.

Then, we'll talk about which items that we still have open with the staff, and where we think we're going with the different open items. Then, I'll cover the purpose of the regulatory treatment of non-safety systems, and where we are with that and discuss those open items.

So with that, we will go ahead and start. And if anybody has questions --

MEMBER CORRADINI: We're not shy.

MR. WACHOWIAK: -- don't be shy. Just inject them whenever they seem appropriate.

So the first thing I wanted to talk about is, what are the objectives of the Chapter 19 section of the design of the DCD? There are several objectives that have been published by the NRC that cover this.

The first one is 10 CFR, the number here 50.34(f)(1)(i), basically states that all new reactors for design certification need to have a PRA. And then, there are other reg guides and other SRP information for what that should contain.

The things that we are looking for here is that we can identify vulnerabilities for the plant, and vulnerabilities in this would be things that would -- that are -- that could lead to an unacceptable core damage or unacceptable release with very few failures following the initiating event.

We are also supposed to demonstrate that we meet the Commission's safety goals. Those are numerical values that we've talked about here. They are the same goals as the existing plants have. We need to show that we meet them.

We're going to -- we need to look at reducing and eliminating the risk contributors from the existing plants. So where we started it with was the issues that have come up in previous plants, and we need to make sure that we handle things that have been significant contributors to existing nuclear plants and make sure that our design doesn't replicate some of the things that there have been issues with in the past.

Select amongst the severe accident management design features. There is a report that goes along with this. That is the Severe Accident Mitigation Design Alternatives. It's the SAMDA, and I think for many of you dealing with life extension there is a similar thing, SAMA, which also includes operator actions, procedures, things like that. But here we are focused on the design.

We are supposed to be able to identify

risk-informed safety insights, and in Chapter 19 there is a table that takes the highest level insights that we came up with from the PRA, outlines them in the plant's FSAR, and also will show where those different things are addressed. If they are addressed by a design, we have identified where is the design. If they are identified as an operational program, then we put in there a marker for the license applicant to make sure they address that in the -- in their program.

Other things in there are basically just listed as insights, things that are important to know about the risk profile of the ESBWR design. So we have accomplished that.

We want to show a balance of severe accident prevention and mitigation. Basically, that goes back into the Commission's safety goals, where we're looking at a low conditional containment failure probability in this plant.

The last couple of things, we want to show a reduction in risk comparison to the existing plants. There is no numerical criteria required for this. It goes back to reducing and eliminating the significant risk contributors from the existing plants, and we were looking to do that.

And then, the last thing is to support some design programs. And I know in the past we have gotten into, well, can this PRA be used to support other programs that are outside the design maintenance rule or the MSPI, and things like that?

But the answer to that is that probably not, that we are looking at supporting design programs and identifying important components that would be addressed in the design phase, and not things that are necessarily associated with other programs that will be put on later. And we'll talk, as we get through this, how that folds in into the future.

So that was where we want to go. So far, our interaction with the staff on this has been pretty extensive, we think. Almost 450 RAIs have come in. Just to keep a tally, that's about eight percent of the total for the whole certification. So it's a significant interaction.

We've resolved almost all of these issues. There are some that are still out there that we are waiting to see if the response is acceptable, and there is an even smaller number that are still out there that we have yet to respond to. But over the last few years we've had extensive interaction with the NRC on the PRA.

Hossein talked about the three onsite audits. The two that have already occurred, and the one that is upcoming in December -- expected to be in December, we'll put it that way. We don't have a hard schedule for it yet, but it's expected in December -- to review -- essentially, it's to do the final review of the Rev 3 of the PRA.

What they will actually be looking at, though, is Rev 4 of the PRA, because our purpose for Rev 4 was to take the things that were in the addenda chapter in Rev 3 and actually fold them into the entire PRA, so they will be looking at the finished product. And that was the plan from the beginning on that. We've had several meetings and teleconferences over this.

MR. HAMZEHEE: But, Rick, there are no major technical changes in Rev 4. It's basically the documentation of Rev 3.

MR. WACHOWIAK: It's the documentation of what was in Rev 3.

MR. HAMZEHEE: Yes.

MR. WACHOWIAK: We do not have any -- other than specific RAI responses that the staff has already seen --

MR. HAMZEHEE: Or findings of the site

visit that we may come up with.

MR. WACHOWIAK: If we find some at that point, yes. So, but the intention was not to have it as an upgrade to the PRA. It's shifting what we've already told the staff into the final document, so that they could see the thing in total, what they have reviewed in pieces up through now.

You know, and I had the -- this on here as three onsite audits, and I noticed that I had the fourth one here. We actually did have a fourth one, but it was a while back, and it was covering the seismic and severe accidents. We -- the audit that was out in San Jose, oh, what, it was probably two years ago now for that one. So that -- I didn't want to forget that.

MR. HAMZEHEE: Yes.

MR. WACHOWIAK: It was mainly a seismic audit, but there was a significant severe accident portion to that audit, where we looked at the containment performance and the fragility of the containment and the parameters that we would need to put into the containment fragility. It was a significant -- significant audit.

Once again, all of the interaction that we've had with the staff on this has focused on the objectives that I had on the previous page. And the focus was looking at, what is it that we need to meet those published requirements with the PRA that we have in hand? And it will be for a later phase when we will do more.

So I mentioned this before, and I want to emphasize it now, because it's -- I think it's important for your review in the letter that you're writing and what you are saying that you are agreeing with -- with the staff.

This PRA is not the last PRA that is going to happen for the ESBWR. Okay? 10 CFR Part 70 -- Part 70 -- 10 CFR 50.71 has a new requirement for new plants that they have a revised PRA covering Level 1, Level 2, basically all initiating events, and it -- it has got to be completed prior to fuel load, and it needs to cover all of the standards that have been endorsed on -- in the PRA area up to one year prior to that scheduled review date.

So the current ASME standards for PRA quality is covered. The upcoming fire PRA standard, which we expect to be endorsed, will be in that mix. There are some external events standards that are in the wings of being released, and we expect by the time the first plant is operating that those will be in place.

So it is at that point where these -- where the ESBWR PRA would be brought up to speed with the things that you are used to seeing for some of the more complex risk-informed applications. So there wasn't ever any intention that the design certification PRA would satisfy all of those requirements. They were looking at satisfying the things that I had on the first page.

MR. HAMZEHEE: Now, Rick, I -- let me just clarify that that rule requirement is not for just risk-informed application. That is a rule requirement for any COL holder one year initial to the -- prior to the initial fuel load that they must have Level 1, Level 2, all initiators, for those that industry standard, endorsed by NRC, exist, regardless of whether or not they would like to apply for any risk-informed applications.

MR. WACHOWIAK: That's correct.

MR. HAMZEHEE: Yes.

MR. WACHOWIAK: And included in all of the endorsed standards so far is the requirement for the industry peer review.

MR. HAMZEHEE: Correct.

MR. WACHOWIAK: So this would also be a

peer-reviewed PRA that would be required for the site. Now, what I have on here is that the site maintains that PRA. They are required to maintain that PRA. But the only time it would be submitted to the NRC is in the context of a risk-informed application.

MR. HAMZEHEE: Correct.

MR. WACHOWIAK: That's the only requirement for submittal there. So it's a question of: where does this reside? It resides at the licensee, unless they are using it for a risk-informed application. But they must have it. By regulation, they must have that PRA.

MR. HAMZEHEE: Correct.

MEMBER CORRADINI: Just for my clarification, from my understanding. When you say "risk-informed application," somewhere during their life, for some purpose.

MR. WACHOWIAK: Risk-informed ISI or --

MEMBER CORRADINI: Whatever.

MR. WACHOWIAK: -- risk-informed tech spec, something --

MEMBER CORRADINI: Okay.

MR. WACHOWIAK: -- something like that, some major application that typically results in a submittal of portions or --

MEMBER CORRADINI: And then, one other clarification. You said the peer review occurs when? You said, and I didn't hear.

MR. WACHOWIAK: The peer review -- the rule says they have to have the PRA by the time they load fuel, before they load fuel. So the way that that has been treated in the past with MSPI and other things is that the peer review must exist, must have been completed prior to the PRA being done.

So the peer review must happen before --

MEMBER CORRADINI: And if we --

MR. WACHOWIAK: -- apply the similar --

MR. HAMZEHEE: Correct. And also, when they say that the COL holder shall satisfy the standards, the standards currently, like Reg. Guide 1.200 and ASME, already have requirements for peer reviews.

MEMBER CORRADINI: Okay.

MEMBER STETKAR: Let me make sure I understand the process, because it's important. If you have 10 COL applicants, you know, you sell 10 of these things, at that point, the --

MR. WACHOWIAK: Can I sign you up?

(Laughter.)

MEMBER STETKAR: Sure. I'll liquidate

some of my money in the 401(k) and, you know, get back to you.

(Laughter.)

PARTICIPANT: It has already been liquidated.

(Laughter.)

MEMBER STETKAR: If I -- what we have now is the ESBWR PRA, and let's say you have 10 COL applicants that load fuel, you know, in 10 successive years, let's say. At that point in time, the ESBWR PRA splits into 10 COL applicant-specific PRAs for which there is no further requirement of staff review, unless applicant number 1, for example, comes in and says, "I want to use my PRA for this risk-informed application." Is that correct?

MR. WACHOWIAK: That's --

MEMBER STETKAR: I don't know if I've characterized that correctly.

MR. WACHOWIAK: That's not exactly correct, and I'll weigh in first, and then we'll let Hossein give some idea on that, too. That is one way that that could go; you'd have 10 successive applicants that would come online, and you would have 10 successive plant-specific PRAs.

Now, the types of things that -- or one

way that it could play out is that everyone would do that on their own. Other ways that it could play out is that the utilities could get together and decide, since we have standardized this plant, maybe we can have a standard PRA with some things in there.

Some of the things that we don't know are standard yet are things like the procedures and training and other plant -- you know, other things associated with what actually happens on that site. So we'll have to talk about how that goes in the future. How does plant-specific data fall into an overall PRA scheme for this?

But the expectation there is that -- that a major risk-informed submittal would be -- you would submit something to do with the PRA, but there are other things that already happen. When you start up a plant, the maintenance rule is applicable to the plant. The maintenance rule, as part of the baseline inspection, includes an inspection of the PRA that was used to develop the lists of things that are used in the maintenance rule program itself.

So, in the past, everyone who has had a maintenance rule baseline inspection has had an inspection of their onsite PRA. We expect that that would go into the future the same sort of way is that when you start your plant up you are going to have a maintenance rule baseline inspection. So at least at that point it would be an onsite audit, but it would be a look at the plant-specific PRA without a submittal.

MEMBER STETKAR: Without a submittal.

MR. HAMZEHEE: No, I think -- let me just clarify what you said, John, in a nutshell was correct. Right now, Part 52 rule says you shall have Level 1, Level 2, all initiating events, one year prior to the initial fuel load for all those that the consensus standards exist, endorsed by NRC.

So that is a rule that says all these potential licensees have to comply with the standards, and they don't have to submit it to the NRC. However, if there is a reason for us, we can always for a specific purpose go and audit and review their PRAs.

On the other hand, if one of these licensees select to apply for a risk-informed application, then we have to make sure that for that specific application that PRA is adequate, and then we do a detailed review for that specific application.

MEMBER STETKAR: So not a detailed review of the PRA --

MR. HAMZEHEE: Because by rule they are

supposed to comply with the standards. And if they don't, they are violating the rule. And at some point -- because right now, for existing plants, there is no rule. The operating plants, the are no rules that say you shall do PRAs. They only do it when either they apply for risk-informed applications or because of all the benefits they get from it.

MEMBER APOSTOLAKIS: Now, Hossein, you said one year before --

MR. HAMZEHEE: Initial fuel load, yes.

MEMBER APOSTOLAKIS: -- initial fuel load, they have to have the PRA. I thought they had to have the PRA before fuel loading, complying with standards in --

MR. HAMZEHEE: That's what I meant, yes.

MEMBER APOSTOLAKIS: Okay. Not the PRA itself.

MR. HAMZEHEE: No. It says that if one year prior to the fuel load the standards exist --

MEMBER APOSTOLAKIS: Right.

MR. HAMZEHEE: -- then before they start the operation, and start in the plant, the PRAs must be completed.

MEMBER APOSTOLAKIS: Right. But not one year.

MR. HAMZEHEE: Correct, yes.

MR. WACHOWIAK: There's a one-year window --

MEMBER APOSTOLAKIS: One-year window.

MR. WACHOWIAK: -- to complete that PRA.

MR. HAMZEHEE: And then, there were some --

MEMBER APOSTOLAKIS: By which time you have the right to audit it.

MR. HAMZEHEE: Correct. Oh, yes, definitely.

MEMBER CORRADINI: I am glad we are getting all the rules of the game settled. But you said something, as you were going back and forth. So that one-year window between the standards you must comply with is where you do the peer review, I assume.

MR. WACHOWIAK: The peer review is typically done following the completion of the PRA. So when the PRA -- so the PRA would have to be scheduled so that it's completed, including the peer review, prior to fuel load, but everything that needs to be in the PRA, and the subject of the peer review, would be the standards, endorsed standards, that are in effect one year prior to the initial scheduled fuel load date.

MEMBER APOSTOLAKIS: Okay. Thank you.

MEMBER BLEY: Just one minor point on that. Assuming the peer review identifies a number of inadequacies, would they have to be addressed before you could call it complete to go to fuel load?

MR. HAMZEHEE: Well, the way the rule is right now, that PRA, before they start the plant, has to be completed. And the answer is, yes, if there are findings from the peer reviews, they have to be incorporated into their PRAs.

MEMBER APOSTOLAKIS: Yes. But the peer review usually addresses --

MR. HAMZEHEE: Because peer review is part of the PRA. In other words, PRA is not complete until the peer review is done, and the insights and vulnerabilities are incorporated.

Now, if there are things that they cannot do, or there are ways to show that it's okay, then that's a different scenario. But peer review is an integrated part of a PRA. It's not a separate activity.

MEMBER APOSTOLAKIS: So you are referring to the peer review, according to the standards.

MR. HAMZEHEE: Exactly.

MR. WACHOWIAK: Yes.

MEMBER APOSTOLAKIS: Not the NEI review.

MR. HAMZEHEE: No, no, no. It's part of the standard that says you do your PRA, then you have to have an independent review, you have to have peer review, and these are the capabilities, these are the requirements of the qualifications of the reviewers, and all those things.

MR. WACHOWIAK: And the one thing -- to get back to the specific question is -- the way that the peer reviews at least are currently formulated is that if the review team has findings and suggestions -- and they all have different levels of severity, if you will, and the -- when you have your review done, you have these findings and you need to assess whether the finding affects what you are using the PRA for.

So prior to fuel load, if you have a finding that affects your maintenance rule, then that probably needs to be fixed prior to maintenance -- prior to continuing. If you have a finding that affects your MSPI, maybe that would also have to be fixed. But if there's findings that wouldn't affect that specific thing, but would be some other use later, then that would fall into this next part of the rule, which is the requirements for when you have to do maintenance and update of the PRA.

And so typically what happens with these other findings is they get schedule sometime into the future, just like in a corrective action program you get -- you schedule when you are going to update those things based on how you're going to use the PRA.

MR. HAMZEHEE: That's correct.

MR. WACHOWIAK: In this particular case now, the rule says that at least every four years you have to do a maintenance/upgrade PRA revision.

MEMBER APOSTOLAKIS: But there is another aspect of this that makes it, you know, a completed PRA to be to everybody's advantage. I assume that you will -- the agency or its contractors will put a PRA on the SPAR models, right?

MR. HAMZEHEE: We have --

MEMBER APOSTOLAKIS: Because these are an integral part of the reactor oversight process.

MR. HAMZEHEE: Right now, all I can tell you is that for the operating plant, as part of the ROP and significance determination process, the agency has SPAR models for all of them, and that's how we do the SDPs.

MEMBER APOSTOLAKIS: Okay.

MR. HAMZEHEE: Once these new reactors become operating reactors, then we may have to follow the same rules and regulations.

MEMBER APOSTOLAKIS: It seems to me you will.

MR. HAMZEHEE: Yes.

MEMBER APOSTOLAKIS: So this is another forcing function here, that you really want to have a good tool for the significance determination process.

MR. HAMZEHEE: Yes.

MEMBER APOSTOLAKIS: So it's not just a risk-informed application that will force people to look at the PRA.

MR. WACHOWIAK: That's right.

MEMBER APOSTOLAKIS: I mean, the SDP itself is important.

MR. WACHOWIAK: And that's why I said that the two -- the maintenance rule and the SDP are -- which I think NSI is part of the ROP.

MEMBER APOSTOLAKIS: Yes.

MR. WACHOWIAK: Those two things we know are coming, and the PRA that is done for fuel load is expected to support those. The other thing that we have in the -- written into the design -- into the DCD is that that PRA would be used to verify the components that are in the D-RAP list.

MR. HAMZEHEE: Yes.

MEMBER APOSTOLAKIS: The most important question last night about the subcommittee meeting was, okay, there will be all these many opportunities to work on the PRA and bring it up to date. But in doing that, would things that are not really changed in terms of COLA, could the applicant say, "You guys have already approved this during the certification process, don't ask anymore questions"? Or is it a new game all together?

In particular -- in particular, some of the stuff you are doing now in digital I&C, three years, four years down the line, whenever you sell 10 reactors, we may have new members. And you come back and say, "Oh, well, you guys approved it."

MR. WACHOWIAK: My opinion -- I'll start, and then we will --

MR. HAMZEHEE: We will start with Rick's opinion.

MR. WACHOWIAK: -- and then we'll move to the maintenance issue.

The rule talks about the updated PRA associated with the endorsed standards. The current ASME standard for Level 1 PRAs doesn't have anything in there that says you don't have a finding if it was in the -- if it was in the DCD PRA. If there is something wrong, it's written up as a finding. There is no out in the current standard.

So I would expect that if they revised the standard to say just what you're doing, that if it was something that was certified, you don't make up -- that review team doesn't make a finding about it, then Hossein will probably stand up and say, "We won't endorse that statement. We'll modify it."

So my -- my opinion on this is that that would not be a valid reason for saying you don't have to put something in the final PRA, because, remember, this PRA was built to support the design certification decision.

MR. HAMZEHEE: That's right.

MR. WACHOWIAK: And it is not expected to be capable of supporting all future decisions. The PRA that you have in the future needs to be able to support the decisions that you are going to make using that PRA. So it will --

MEMBER APOSTOLAKIS: Even if it requires a revision of some of the things you are doing now.

MR. WACHOWIAK: Exactly. So if we have -- if we have an I&C standard that is endorsed, that says to do something, it's endorsed prior to that, it has to be upgraded to that. There is no shield from a design certification PRA. A design certification PRA answers the question, "Should the plant be certified?"

MR. HAMZEHEE: And that was the reason that the Commission put in the rule specifically that once you're done, you're not done for the life of the plant. Every four years you have to go back and upgrade it. And upgrade means if all of a sudden we have new ways of doing the modeling of digital I&C, because we learn more about how the software can fail, we have more information on common cause failure events, then we go back and say, "Guys, you all have to go back and upgrade your PRA," because now we know more about digital I&C. Ten years ago we didn't have enough information.

MEMBER CORRADINI: Okay. Have we gotten the ground rules set?

PARTICIPANT: I think so.

CHAIRMAN SHACK: Move on.

MR. WACHOWIAK: Okay. Well, and I think these are important ground rules, because there has been confusion about this all throughout our discussions over the last year.

I want to put my pitch up here. The ESBWR design certification PRA does meet the scope and quality necessary for certification. And as long as a

COL applicant doesn't take any departures from things that are modeled in the PRA, then theirs is -- then the design certification PRA is sufficient for a COL at that point, to grab a COL.

And we did this because we drew the boundary around what we were going to model in the PRA, sufficient so that we could make this statement. And we expanded some things, we put some things into the standard design that originally had been planned to be site-specific work, conceptual design in the design certification. We expanded that boundary, so we could make this statement.

Once again, it provides a -- it is intended to provide a starting point for the operating plant PRA. It is not the operating plant PRA.

MEMBER BLEY: I'm -- if the COL -- I thought we have to have all initiating events included, and you don't have all the initiating events included at this time. The externals aren't there, to some extent.

MR. WACHOWIAK: The externals are there.

MEMBER BLEY: Well, not in -- plant-specific enough to stand up for the COL?

MR. HAMZEHEE: Well, when they submitted COL application, the external events must be included.

However, they don't have to be, for instance, fire PRA. There are other methods that have been allowed for the COL application phase, such as fire methodology --

MEMBER BLEY: But that's not in the current --

MR. HAMZEHEE: I'm sorry.

MEMBER BLEY: It doesn't exist for the current PRA.

MR. WACHOWIAK: Yes. Yes, it does.

MR. HAMZEHEE: No. They have to address all of them also.

MR. WACHOWIAK: A modified fire PRA.

MEMBER APOSTOLAKIS: The seismic is the margins.

MR. WACHOWIAK: Seismic margins, and then there's a section where we discuss other types of external events, like nearby facilities and --

MEMBER BLEY: For seismic, all they'd have to show is that they are bounded by the source term you have considered. I mean, they -- I don't mean source term, I mean hazard.

MR. HAMZEHEE: Also, for seismic they can either do seismic PRA or they can do seismic margin analysis to show that there are no vulnerabilities due to seismic.

MEMBER APOSTOLAKIS: And you assume a .3g that --

MR. HAMZEHEE: Whatever -- well, then, they either have that --

MR. WACHOWIAK: We can talk about that when we get to that --

MR. HAMZEHEE: Yes.

MR. WACHOWIAK: -- that piece of it.

MEMBER APOSTOLAKIS: Anyway, they --

MR. WACHOWIAK: That one is -- that's an interesting thing. We tried to look at something that would be more site specific, but it turns out it didn't work out that well for the certification. So it's a bounding seismic PRA.

But, remember, the question that we're answering at the DCD stage, and at the COL stage, is: is this plant imposing undue risk? And if you do a bounding external hazards, you can answer that question in a positive way, that it doesn't pose undue risk. You may not be able to take it and say that I get all the same insights that I need for things like maintenance rule and MSPI from that. And that would happen in the future for --

MR. HAMZEHEE: And let me just make a

quick clarification. Also, let's say GE decides to do the seismic risk assessment at the .3g, and let's say Diablo Canyon decides to use an ESBWR, build it in California. And they have a much higher earthquake -- design basis earthquake level. Then, they have to do a site-specific seismic analysis, because .3g is not adequate for them.

MR. WACHOWIAK: Exactly. And that's where it comes into given no significant departures. If you go into the COL, and you look at their list of departures, if they --

MEMBER BLEY: Fair enough.

MR. WACHOWIAK: -- a departure from the hazard curve, then you need a site-specific COL PRA.

MEMBER STETKAR: To make sure that I -- this is COL application, not --

MR. WACHOWIAK: Application.

MEMBER STETKAR: -- fuel load.

MR. HAMZEHEE: No, no, no, no. That's right.

MEMBER STETKAR: Okay.

MR. HAMZEHEE: This is the transition period from the design certification phase to the COL holder.

MR. WACHOWIAK: Yes. Operating plant is

what I meant by fuel load.

MEMBER STETKAR: Okay.

MEMBER APOSTOLAKIS: We are not deciding right now whether this plan poses undue risk. These words are not used anywhere. We are decided that it is consistent with the Commission's goals, and everything else you have on your slide.

MR. HAMZEHEE: Correct.

MEMBER APOSTOLAKIS: The undue risk is for the future.

MR. WACHOWIAK: I stand corrected. That is -- we are reviewing what I did on Slide -- meant on Slide 2.

MEMBER POWERS: But if we find undue risk here --

MEMBER APOSTOLAKIS: It's a problem.

MR. WACHOWIAK: I tried to use some shorthand, and I --

MEMBER APOSTOLAKIS: No, no, no, no. That's okay.

MR. WACHOWIAK: So now I want to get into what it is that has been reviewed and the documents that you would be looking at. So our PRA -- the submitted part of the PRA is in several pieces. We have DCD Chapter 19, and it's -- it describes the PRA and lists the key insights.

If you want to get into what is in the PRA itself, you'd need to go into the NEDO document 33201. That's the report of the PRA itself, and many of you have looked at various revs of this. Rev 3 is the current revision.

We also have a NEDO 33289, which is our reliability assurance program, and it contains a description of how the PRA is used for the reliability assurance program.

33306 is the severe accident mitigation design alternatives, the SAMDA that we talked about. I know somebody was looking for a copy of that before. This is the number that you had looked for. And currently Rev 1 is out there, and that matches Rev 2 of the PRA. As you read through there, you will probably see why we don't think we need to update that particular document, at least in this -- right now.

We have a combination NEDO and NEDE. That is our document or our naming for things that have public and redacted pieces. The NEDE is the full document. It describes the flood zone drawings and fire zone drawings, other information that was needed for pieces of the PRA.

And it needed to be done this way because we wanted the -- we did not want the PRA to have redacted pieces all over the place for the SUNCI material, the sensitive unclassified, whatever. We didn't want any of that in the PRA document. So what we did was we just moved all of that information into this separate document, which its purpose is to contain -- is to hold that sensitive information.

So if you want a quick read, you can read the public version of that document. I think it's a cover page, and then 450 blank pages after that.

(Laughter.)

But that was the purpose of that document was to -- is to be a container for things that we would redact from the PRA.

The next one is another document that is part public and part proprietary -- the MAC experiments which were done to -- to demonstrate the capability and also fine-tune the design of the BiMAC.

Rev 0 is the current one. And then, finally, the 33411, which is the first implementation of the D-RAP categorization criteria. And that I guess has recently been submitted and is going to be used some -- to some degree in the prioritization of inspections of mechanical equipment.

Go ahead.

MEMBER STETKAR: That last one is the one that I have a hang up on, because that actually is an application of the design cert PRA. It's the only application that I can divine from this, other than the general -- this is a specific application. It's being used to make decisions about these.

Now, I'm troubled because, you know, if I bring up -- those of you who haven't been in the subcommittee meetings, if I bring up my favorite valves that I know about --

(Laughter.)

-- these are not in the PRA. It's difficult for me to understand how that PRA satisfies the quality requirements to make decisions about pieces of the plant that may be important to risk when I don't have all of those pieces of the plant in there.

MR. HAMZEHEE: Let me --

MR. WACHOWIAK: We'll let Hossein start --

MR. HAMZEHEE: Let me take a crack at it, because I have been working on this in the last six, seven months, and there are some ideas and concerns.

D-RAP is almost like the way -- design reliability assurance program is almost like the PRA phases. We have design certification phase of D-RAP that the purpose of design reliability assurance program is, based on the available information, at the design stage make your first attempt to identify risk-significant SSCs that you think are -- that based on your design information are risk significant, and then there is a process that says how you have to identify dose, how you take PRA information, as well as some deterministic information, some expert panels, all those things, and how to include all the risk elements into your consideration.

So when the design is certified, they have that D-RAP, but when the COL application comes in, then they have to take that D-RAP and say, "All right. Now, I'm going to have more information." And as they go closer to the COL holder, then that prioritization list is going to change probably, based on the new information and more detailed information that they have.

MEMBER STETKAR: Except if I do not have a valve in the model, and I do not change the plant design from the design cert stage to the COL stage, there is no requirement for me to put that valve in the model. I do not have the volume control, if you will, to try to adjust to determine whether or not I need to change my surveillance interval.

For example, if I have the valve in the model today, and the best I know is that today there is a functional test that is performed once every 10 years to verify flow for that -- through that valve, the combination of the valve failure mode and that functional test interval, the best I know today, would give that valve some ranking in terms of risk significance.

MR. HAMZEHEE: Right.

MEMBER STETKAR: I don't know what it is.

MR. HAMZEHEE: Correct.

MEMBER STETKAR: At the COL stage, I might decide to change that test interval, for whatever reason. Might -- instead of 10 years, it might be five years, or I might make it 40 years. I don't know. I could then measure the change in importance of that valve based on a decision that I made from the design certification stage to the COL stage.

If the valve isn't in the model, I can't investigate that change.

MR. HAMZEHEE: Now, are you saying --

MEMBER STETKAR: And I can't -- I can't measure its impact on the risk, even today, because it's not in there.

MR. HAMZEHEE: Now, are you --

MEMBER STETKAR: That's my concern.

MR. HAMZEHEE: Yes, I understand. And are you saying that that valve is not included by mistake or intentionally?

MEMBER STETKAR: At the moment, I know it's intentionally not included.

MEMBER CORRADINI: We're clear by the discussions in the subcommittee that you felt there wasn't a large risk contributor. Therefore, you did not specifically model it.

MR. WACHOWIAK: Using the rules that we had when we originally put that model together, it did not make the cut for going into the model. We revisited that, because we've done some additional modeling in the BiMAC, and it -- and it doesn't quite meet those rules anymore.

So one of the things that we have to do is make sure that -- that that's correct, and that's one of the things that we now know about. And it's not just those valves, it's the class of valves that we had excluded from the model.

MEMBER STETKAR: I was going to say, I only used this -- this one valve as a --

MR. WACHOWIAK: We understand that, and when we go and look at these things we typically don't look at them one component at a time. We have to look at the -- at, what is your broad question?

So getting back to your original question on this, using this initial set of risk-significant components, what is the purpose of this? We have had extensive dialogue back and forth with the staff on how this list should be used.

And in the D-RAP program what we have decided is it should be used as an initial list to demonstrate that we know how to create these lists and then -- and how to move forward from when we actually use these things in a maintenance rule and such.

It has now also been asked to use -- and we think that that's an okay way to use the list, because, really, our PRA is built more to identify importance at the system train level rather than at the component level. And that's what we thought we had to do. But there's a requirement for this list, and it's a component-level list. So we've got the ground rules down for how we think that list should be used.

Now, we have other areas in the NRC that are -- that want to use this list to try to prioritize certain inspections. And we're just in the beginning of that discussion right now and how to understand how to use this list to prioritize inspections.

And if -- when we're -- when we get to the end of this discussion, that we can come to an understanding with everyone that you should use it -- even though it's got components listed, you should use the list as a system-level importance and prioritize your inspections on a system basis, which is what I believe they are going to do anyway, because I don't think the database for inspections goes to a component level. I think it's more of a -- I think we'll be in the ballpark for what we need to do.

But this document is written such that this is identified as a preliminary list based on the information that we know now, and that it is intended to be updated as more information becomes available.

MR. HAMZEHEE: So if a valve is by mistake not included, or intentionally, that these are two different cases, John, right? Because if they are intentionally not included, it is based on some evaluation, some analysis.

MR. WACHOWIAK: This is one of the things -- and it gets back to maybe the PRA standard committee, because we thought about this since -- since then, and I have also participated in a peer review for a utility since then, and the question comes down to this completeness.

And I think you pointed out which statement it is you need to be complete, and the instructions that we -- that the industry has been given is that if -- it's complete, as long as it doesn't change the results by too much. Whatever the too much is, okay, that's up for debate right now. But until you know the application, you don't know how much it changes the results. You only know with respect to the base model.

So your particular question there would come into play for any PRA that, by intention, excludes or screens things --

MEMBER STETKAR: That's right.

MR. WACHOWIAK: -- based on some set of rules, and then you -- later you use it for an application where that screening set of rules may not be correct. So I think this is --

MEMBER STETKAR: That's correct.

MR. WACHOWIAK: -- bigger than just the ESBWR PRA.

MEMBER STETKAR: No, it's -- that's -- you're absolutely right, Rick. That's fair.

My -- I think that's true, and I think you have to be a little bit careful about speaking in the context of existing PRAs and whatever they are -- whatever form they are for the existing operating fleet of plants, and however those PRAs are or are not being used, versus where we are today in 2008, looking forward to the future, for PRAs for the new plant designs, and how will they be used, either in a regulatory sense or by the licensees.

And, as a practical matter, the pragmatism of putting things into a model today in 2008, as compared to 25 years ago when a lot of these judgments were made about how you can screen things out to keep the model small enough so that, a) your software could solve the model, and b) solve the model in a time that was not geological.

MR. WACHOWIAK: And I think, though -- you missed one thing, though, for where we are today.

MEMBER CORRADINI: After this one thing, we must move on.

MR. WACHOWIAK: And we --

MEMBER CORRADINI: I think you guys are on the philosophical same plane, so --

MR. WACHOWIAK: Yes. I think the thing that you missed was Reg. Guide 1.200 was released about a year and a half ago, and all the existing PRAs have to be brought up to that standard if you're going to use them for --

MEMBER STETKAR: If they're going to use it.

MR. WACHOWIAK: And MSPI, if you're going to change data in your MSPI, that's using them.

MR. HAMZEHEE: Go on with --

MR. WACHOWIAK: All right. So done with -- we'll go through most of these, because I think most of us have seen this before, talk about the key features of ESBWR risk management. We know we're a passive plant. But, once again, we want to use active systems to back those things up.

And our design philosophy is you have -- for every -- for every function you have some passive way of doing it, backed up by one or more active ways, and you have multiple diverse support systems. And in that way, just before you model anything, designing the plant is going to end up with something that has a risk profile that is going to be found acceptable to us. Then, we have the other words on there that we've talked about before.

To go back to what we have included in our PRA, it's a fault tree/event tree model. It covers Level 1, 2, and 3. Level 3 is using the generic site. Once again, that was determined to be okay for the

COL as well.

Internal and external events we have covered. All modes -- we've done it in a bounding way where we've subsumed some low power modes into our full power mode, and we've addressed why that is okay.

Seismic margins for seismic -- we used generic data, historical initiating event frequencies, and screened for -- for things that are no longer in the plant. So we only removed things that are no longer in the plant.

We do parametric uncertainty, and we have -- this is the key to some of these other things -- a systematic search for modeling uncertainties. The way that we went through this in our models was we had all of the engineers that created a model write down a list. What are all your assumptions? And in a new plant PRA that the plant has not been built everything is an assumption. Okay? Write them all down, including what you put in the model and what you excluded from the model.

Then, we screen all those, and some of them make it into the PRA report as important insights, and then they are screened again with respect to the things from page 2, to see if they make it into the key insights table there.

But in our -- in our documentation, we have the list of all the things that we didn't model in the plant. That is already on our list of assumptions that we have there.

We did an internal review for compliance with the ASME standard, and I guess I should say "slash Reg. Guide 1.200." At the time, Reg. Guide 1.200 wasn't the -- wasn't required -- a requirement at the time. So we used the -- at least in its incarnation we used this, and the interim staff guidance says that an internal review by the vendor is sufficient for design certification. So that's where we are with that.

Risk profile -- as we said before, we won't get into the details of this. It's a nice, balanced profile. There isn't any one particular initiator type that dominates risk. We did that by design.

MEMBER POWERS: Can we go back to the previous slide? Did the subcommittee explore your parametric uncertainty analysis?

MR. WACHOWIAK: There have been some questions about that in some of the previous presentations.

MEMBER CORRADINI: Dana, can you -- can

you expand on what your question is? I'm sorry, I don't --

MEMBER POWERS: I'm trying to find out -- it is apparent you are not going to go into that parametric uncertainty here.

MEMBER CORRADINI: No.

MEMBER POWERS: I'm trying to find out if the subcommittee explored this with you.

MEMBER CORRADINI: We're talking about -- but I'm still -- I'm sorry that I'm still not clear what you are thinking of when you say this. I'm sorry. Can you expand a bit more?

MEMBER POWERS: What I want to know is, did they address correlations among parameters? How did they set distributions for parametric values? How did they set the --

MEMBER APOSTOLAKIS: They used -- I believe there was some discussion -- I'm not sure about the correlation --

MEMBER STETKAR: There wasn't a lot.

MEMBER APOSTOLAKIS: -- the correlations, we -- would you use a 100 percent correlation, state correlation for similar components?

MR. WACHOWIAK: Yes.

MEMBER STETKAR: We looked at high-level

things like that. I know we looked at the failure rate distribution and how it was derived for a couple of -- some interesting pieces of equipment. But in terms of in-depth examination of the parametric distributions themselves, and how the uncertainties were actually propagated through, I certainly didn't look at that.

MEMBER CORRADINI: Well, I was going to say, I'm not sure -- I'm still not sure if I'm -- we're answering your question. Are you more interested in the modeling uncertainties of -- for example, in BiMAC operation, or are you interested more in terms of passive system reliability? They did do -- they did do MAAP. We saw -- we asked for and got MAAP versus TRACG calculations and the effect of modeling uncertainty between those, but not a full uncertainty analysis. Is that -- are we getting closer to what you're interested in?

MEMBER POWERS: I am interested in the mechanics and the details of how they did the parametric -- their parameter uncertainties.

MEMBER APOSTOLAKIS: They assumed 100 percent correlation for similar components. But the distributions -- 99 percent of them are log normal, right? And it was Monte Carlo propagation. This is the -- what people do more or less routinely for PRA. Some of the issues that you raised on Tuesday I don't think they addressed, but they did what you would expect to see in a standard PRA.

MR. WACHOWIAK: And the only thing that remains open in my mind from the Rev 3 that you may have looked at is that the database that we had in the report needed to be modified with additional distributions in order to complete this analysis. And that -- and that set may not have been the one that was in the report.

I think for the -- since that came up, we're making sure that the -- the UNSR database is the one that we actually put in the report. It was a timing thing. We had the -- that section of the report done before we did the other one.

MEMBER BLEY: There was -- since I heard yesterday that -- or the day before that all of these are parametric, I guess there's one area I'd like to add in. We -- Rick described to us how they tried to address new initiating events that might exist for this kind of plant, through a systematic process, and yet I still haven't found the documentation of that. The description was good.

MR. WACHOWIAK: You've seen our internal

-- it didn't make the report. The question could come out, and we could move that forward. But, once again, hot 100 percent of the things made --

MEMBER POWERS: I guess it bothers me to hear that 99 percent of your distributions are log normal. I would have expected -- but there surely must be a reason.

MEMBER BLEY: I think tradition is probably -- the database that we picked for our generic data came from the EPRI URD and the distributions they have in there.

MEMBER APOSTOLAKIS: Are these results point estimates?

MR. WACHOWIAK: Point estimates. It says on the bottom, "Point estimate" --

MEMBER APOSTOLAKIS: It says that. Okay.

MR. WACHOWIAK: -- "UNSR for calendar year" --

MEMBER APOSTOLAKIS: Because I remember when I read the report that the mean value I believe -- after you do the parametric uncertainty propagation, seven 10^{-8}, or something like that. So it's higher. Not an order of magnitude, but it is six or seven 10^{-8}. It's on that order, Rick.

MR. WACHOWIAK: I think one of the earlier versions had that, and in Rev 3 it was nearly the same --

MEMBER APOSTOLAKIS: Really?

MR. WACHOWIAK: -- as this one.

MEMBER APOSTOLAKIS: I would expect it to be higher.

MR. WACHOWIAK: It would. But, remember, we do have a balanced risk profile, and there are --

MEMBER APOSTOLAKIS: So when you --

MR. WACHOWIAK: -- contribute evenly.

MEMBER APOSTOLAKIS: So the point estimates you inserted into the calculation, what the mean values of the underlying distribution --

MR. WACHOWIAK: Yes.

MEMBER POWERS: You conclude from this slide that the only time I worry about your plant is when you're shut down.

MR. WACHOWIAK: The time -- well, let's back this up another way. Based on this, you should conclude that you don't have to worry about this plant.

(Laughter.)

But if you were going to worry, then the shutdown is more important, mainly because one of our key features is taken away in this assumption, or in this particular model for shutdown we model a refueling outage, and we take away the containment. When we take away the containment, we take away some of our past features. So this -- this distribution is completely expected.

MEMBER CORRADINI: So you have a pretty open -- in fact, that was the key thing, if I remember, when you were describing this at the subcommittee.

MR. WACHOWIAK: The LERF is the same.

MEMBER POWERS: That's remarkable, because your most hazardous configuration is a fire during shutdown --

MR. WACHOWIAK: And we explained that --

MEMBER POWERS: -- containment.

MR. WACHOWIAK: And because the systems that would mitigate a transient induced by the fire are taken away by the containment not being there. And we also describe in the report that due to many of the bounding assumptions in the fire PRA, for example, there is no mitigation -- or there is no fire suppression modeled, either automatic or manual, that's not modeled, and we also don't do specific target set fire modeling.

So a fire -- any fire in any area is

assumed to affect everything in the area. So we believe that's a bounding number for fire, explained that in the report, and you're correct, it is the highest number on the --

MEMBER APOSTOLAKIS: You did do some --

MEMBER POWERS: What we want to do is have fully enriched fuel here, so you never shut down.

MEMBER APOSTOLAKIS: Can you remind us real quick, because I remember there was --

MR. WACHOWIAK: We did several sensitivity analyses on these various things, and we looked -- in the fire area, in particular, we looked at things like, is it important to maintain the fire barriers during shutdown? The answer turned out to be yes.

And other things that we looked at were sensitivities to where we would place equipment. I'll get to that in another slide, hopefully in the next few minutes here.

MR. HAMZEHEE: We still have the staff's presentation.

MR. WACHOWIAK: Right.

MEMBER CORRADINI: He is going to get there.

MR. WACHOWIAK: I still have 15 minutes, according to -- because we have to factor in the questions.

MEMBER CORRADINI: We started 15 minutes late, so keep on going.

MR. WACHOWIAK: Okay. In the severe accident analysis, the scope, we have discussed this before. There are things in the rule that says you have to discuss prevention. That's the Level 1 essentially. And then, you discuss mitigation. The things that we looked at -- hydrogen control, debris coolability, high pressure melting -- those types of things, and then the SAMDAs.

This information is contained in DCD Chapter 19, and then also in the NEDO in Section 21, and then in the BiMAC report. Or, I'm sorry, this is I believe the SAMDA report.

Okay. One of the things that I wanted to point out was that the PRA was a major influence on the design. It was a good thing to do while we were designing the plant. Some examples -- even though we can't fully model the digital I&C, we still had a major impact on using our information in the model for how we would set up the interface between the digital and the mechanical equipment, so that we can minimize things like spurious actuations due to fire. And we -- we added features to the digital I&C system so that it would specifically perform this.

Selection of diverse components -- when we looked at how we wanted a system to -- to behave, one of the things that the PRA always looked at is, okay, you put in the system, so where is the diversity, so that we can -- so that we minimize the impact of the common cause in specific systems.

Added redundancy to the reactor water cleanup isolation valve. There was a specific outside containment that basically was -- would have been high on the risk meter, if you will, when we finished the results. And it also resulted in the containment bypass, so we added features to try to minimize that. Added the BiMAC to add additional protection to just the spreading area on the floor for the ESBWR.

MEMBER ABDEL-KHALIK: There were some questions regarding the thermal hydraulic performance of the BiMAC. Are we going to address those at some time in the future, Mr. Chairman?

MR. HAMZEHEE: I think the -- also, NRC staff has some RAI on it and will talk about it.

MR. WACHOWIAK: We still have open RAIs on that.

MEMBER CORRADINI: So the answer to your question is yes.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MEMBER CORRADINI: We have to come back and hear their responses. They still are working on responses to staff.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER APOSTOLAKIS: Which one of these are purely or almost purely defense-in-depth measures?

MR. WACHOWIAK: Which ones are purely defense-in-depth measures?

MEMBER APOSTOLAKIS: In other words, you are pretty confident you have a safe plant, but you are going to do some of these as extra defense-in-depth.

MR. WACHOWIAK: The BiMAC is certainly one of those.

MEMBER APOSTOLAKIS: Okay. Go even if it doesn't work very well --

MR. WACHOWIAK: We are no worse off than --

MEMBER APOSTOLAKIS: -- you are no worse off.

MR. WACHOWIAK: -- than ABWR.

MEMBER CORRADINI: Now, since you said --

(Laughter.)

-- since you said that, and he was my

straight man for this, is there analysis that shows that?

MR. WACHOWIAK: There was an RAI where we were asked that particular question.

MEMBER CORRADINI: And so it's still being developed.

MR. WACHOWIAK: And we -- no, we answered that RAI.

MEMBER CORRADINI: Oh.

MR. WACHOWIAK: And the question there is is I don't know exactly how -- how -- if that's in the final report, or if it was covered in the audit, or where that ended up. I -- I probably should have looked that up to see where that ended up, but we did --

MEMBER CORRADINI: We'll save that.

MR. WACHOWIAK: -- the analysis, and it was given to the staff and they reviewed it.

MEMBER CORRADINI: Okay. That's fine.

MR. WACHOWIAK: In addition, in a severe accident, water injection pump is another thing that it was -- basically came in from the PRA. That's another defense-in-depth measure there. And we have identified enhancements that will be resolved during procedure development, and in the Chapter 19 set of insights there are several of these that say, "When you write your operating procedures, consider this insight and various other things." But there are more insights that came from the PRA that will be done in a later phase, but they are just not done now.

MEMBER APOSTOLAKIS: Let me ask you this, though. The first bullet, okay, what exactly does that mean? You said you wanted to prevent spurious actuation.

MR. WACHOWIAK: Yes.

MEMBER BLEY: It says eliminate. This is not prevent; this is eliminate.

MEMBER APOSTOLAKIS: Limit it. Okay. So how --

MR. WACHOWIAK: The goal is to eliminate it.

MEMBER APOSTOLAKIS: Can you explain, how does that work?

MR. WACHOWIAK: Yes. The --

MEMBER APOSTOLAKIS: Don't worry about that.

MR. WACHOWIAK: The way that it works is our -- first off, our I&C -- the communications amongst the I&C systems is all by fiber. So that's the first thing. We don't have a long wire that is running from the control building over to the cabinet for the actuator that is susceptible to some sort of an impact there. That is all done by fiber.

Then, once we get into -- we recognize that once we get into the cabinet, though, if the control cabinet itself has an issue due to fire, the control cabinet could send the signal out to actuate one of the squib valves, or more of the squib valves, something like that.

So instead of just taking the power from that room in the cabinet and running it to the device, we put two cabinets in separate fire zones on separate floors of the building. So the power comes in from here, has to go through this cabinet, then through this cabinet, and then out to the field. That way, you have to have a simultaneous fire in two different fire zones before it is even possible to get a hot short that would actuate the device.

And we are also now in the process -- you know, that was -- that was originally the goal, to eliminate -- there is one last thing that we need to address with that, and it's being addressed right now, is the smoke propagation that could potentially cause those actuations, and that's something that we have answered to the staff, we think we have the answer.

MEMBER APOSTOLAKIS: And you left it at that. You just did that. You didn't attempt to probabilistically -- which is fine with me, if you --

MR. WACHOWIAK: What we did was we assumed -- we made a deterministic, we thought bounding assumption, was that if the fire barrier failed, then it -- we would have spurious actuations. So that's how it got into the probabilistic portion was that if the fire -- if the fire barriers work, we calculated those probabilistically -- the failure rate of the -- failure probability of the fire barriers. If they worked, no spurious actuation. If the fire barrier fails, spurious actuation.

MEMBER APOSTOLAKIS: It seems to me that that would be an acceptable approach to the whole issue of digital I&C systems.

MR. WACHOWIAK: We think so.

MEMBER APOSTOLAKIS: Rather than saying that there is a probability of six times 10^{-4} of a common cause failure. This would be perfectly fine with me.

MEMBER CORRADINI: Move on, please.

MR. WACHOWIAK: Okay. The other piece of this is we had -- we had the extensive review with the staff, and their review also influenced what the PRA actually ended up looking like. Originally, our Level 3 was only -- was only internal events, and questions about, well, how does it affect external events, we extended the model to include that.

The enhanced documentation of assumptions that we talked about earlier basically started out from questions that came from the staff over and over again about how we did -- how we addressed certain assumptions, and finally we ended up coming up with this systematic process for documenting the assumptions.

Question earlier, did we -- I think zero and one, used five methodology for fire, and when we went to Rev 2 we went to a fire PRA in accordance with the new NUREG that's out, to the extent possible. There are still some things we can't do there.

And then, other things, this review -- systematic review of the PRA with respect to the standard was a question that came from the staff. We had done it piecemeal, and then after that question we went ahead and did a systematic review. So we think that that helped enhance our final product.

Okay. Now, getting to open items, and Hossein is going to talk more in detail about what these open items are. But there is really four or five areas here. That's this quality assessment that we talked about. We have submitted the results of that. We think we are on a path to success there. And, once again, the audit is supposed to close that out.

Seismic margins analysis -- we -- last time we met with the subcommittee in June we -- we said that there was a problem associated with seismic margins and which hazard curves we used for the seismic margins. Right now, where I -- we think we're on a path to success here using the certified design response spectrum.

Since we talked, Hossein, I have seen the results from our most-limiting building, and we are okay on the most-limiting building. We just need to expand that now to all the rest of the components that were done there. So it looks like we're on a path to success for the seismic margins, using the response spectrum that was requested.

In the high winds analysis, there is still an open item here on the assumptions of the building capabilities and extremely high winds, and whether we should treat it probabilistically or deterministically.

We are working on the response for that, and when we know the answer then we will -- we will come back. But this is a problem that I haven't seen addressed in PRAs before, so it's a -- the question that came from the staff is: do you have a building fragility associated with the failure of the buildings during the high wind events? And, once again, there may be something out there for that, but it's not something that I have encountered, how you generate those fragility --

MEMBER BLEY: Yes, people have them. Yes.

MR. WACHOWIAK: So, great. If you could send me a reference, then I'll --

MEMBER POWERS: When you think about high winds, you're thinking in terms of hurricanes and tornadoes?

MR. WACHOWIAK: Yes.

MEMBER POWERS: And since you are designing this plant for many years of operation, maybe 80 years of operation, do you have to think about for the -- how often we would get high winds in various parts of the country? How do you think about that?

MR. WACHOWIAK: We did a couple of different things. The first thing that we did is for hurricanes the data that we used was only the coastal data. So we think we -- for the hurricane type winds, we didn't average in all the different sites. We tried to use the coastal sites.

Then, we also looked at --

MEMBER POWERS: So it would be different than for Gulf of Mexico versus the Atlantic or --

MR. WACHOWIAK: Yes. And we looked at the data that we had there for -- for trends like that, and the Gulf -- I think it's the Florida peninsula and the Gulf of Mexico is where the concentration of the data was.

So if we -- by the way we applied this, we think we set up a bounding -- questions yet that were out there, are these frequencies going to change going into the future? We did some sensitivity analyses to address that, but we think we have got that set up correctly.

The other thing -- for tornadoes now we used -- okay. You're mainly interested in the hurricanes, then.

MEMBER POWERS: Now, you're a little bit too glib there. You say you think you've got it set up. I mean, do you -- you prognosticated about the future. I mean, how do you do that? I think you may be wrong about that. I think the richer data set is the Atlantic coast, and the poorer data set is the Gulf of Mexico data set.

MR. WACHOWIAK: I probably didn't explain exactly how we did this in enough detail to get that. The data that we used for the -- for the hurricanes was based on the coast to determine what the fraction of Category 1, 2, 3, 4, 5 hurricanes would be.

But the data -- but the frequency itself of the upset condition at the plant was based on the upset conditions at actual coastal plants. And the plants that had hurricane-related disruptions were Florida and then the Gulf Coast. So to determine what the fractions of the different hurricanes are, we used the NOAA data. But to get the frequency at a site that there would be an upset, we used site-specific data from upsets.

MEMBER POWERS: You've just got a lot more plants in Florida, so, yes, you obviously used that.

MR. WACHOWIAK: And, actually, I think if you go through and look at the data, you might even screen two of the three events out, because they weren't necessarily associated with the high winds. They were associated with something else other than that. So --

MEMBER POWERS: But now, how did you

prognosticate to the future? Who is to say that historically that is the same as going to be -- what we saw in the past is what we're going to see in the future?

MR. WACHOWIAK: For the base frequency, that's what we did, and then we did a sensitivity analysis by increasing those frequencies to see where the break point would be, where it would become a significant contributor.

MEMBER CORRADINI: Can you remind -- before we move on, can you remind Dana what you found by that sensitivity?

MR. WACHOWIAK: If I remember correctly, and it's something that we're going to have to go back and look at, I think that we found that even a factor of 10 increase didn't make hurricanes a significant contributor.

MEMBER POWERS: Using the same distribution of one to five categories.

MR. WACHOWIAK: Yes.

MEMBER POWERS: I can find people that say that that distribution is going to change in the future.

MR. WACHOWIAK: That's true. You can find people that will say that.

(Laughter.)

And you -- that -- we think that the sensitivity that we looked at there is the appropriate one, mainly because we raised everything together. So the frequency of the -- of the higher would be also increased, as well as the frequency of the lower.

The complement of equipment that we use to address the higher wind speeds is greatly reduced compared to the complement of equipment that we use for the lower wind speeds, because the buildings are designed for up to the -- I think the site wind speed is 155 mile an hour hurricane. So --

MEMBER BLEY: I'm not sure I understood what you just said, that sentence.

MR. WACHOWIAK: Okay. The buildings that we have -- the buildings part or why I think that the distribution is --

MEMBER CORRADINI: Just say it again slower.

MEMBER BLEY: Say the whole thing again slower.

(Laughter.)

MR. WACHOWIAK: When we looked at the sensitivity, we increased all the frequencies --

MEMBER BLEY: That part again.

MR. WACHOWIAK: -- one, two, three, four all together. And we looked at the overall effect. The model looks at all the different distributions. So the -- what we wouldn't expect is to see a factor of 100 increase in Category 5 hurricanes with a factor of zero increase in the Category 3. So I think that's part of what the question is, is did you vary the distributions between those?

MEMBER BLEY: What I really wanted you to say over again was the part about the set of equipment that you looked at for different --

MR. WACHOWIAK: Okay. The set of equipment that we used is reduced in the higher wind speeds, because as you get to the different wind speeds, when we move outside the envelope of design for a certain non-safety-related building, we no longer take credit for any of the equipment in that building.

MEMBER BLEY: Okay. That's what I didn't follow when you said it the first time. Okay.

MEMBER POWERS: But you did -- just did a sensitivity study. You didn't -- and you jacked it up by some factor of 10? Okay.

MR. WACHOWIAK: Yes.

MEMBER POWERS: I mean, I don't know of

anybody that's proposing a factor of 10 increase, so I certainly --

MR. WACHOWIAK: And, once again, we will need to check on exactly how that sensitivity was, since I didn't review that just before I came in this morning, but it was -- it was on that order. And then, remember, what we're doing here is we're looking to see, for that particular thing is, are there any key insights that come from that that we would put in Chapter 19?

So, once again, if you went to a factor of 10, and it didn't encroach on any of the safety goals or the other parameters with the -- in the -- that we looked for with the PRA, then we can say confidently that it's not going to generate anything different with the design.

So we do know the exact number for every site? No. But we think that we know enough for every site that high winds is not going to be a way that you could push the plant to a point where it wouldn't meet the Commission's safety goals.

MEMBER BLEY: I hate to admit there is a hole in my reading, but was this described in the PRA, the sensitivity studies?

MR. WACHOWIAK: The sensitivity, I -- we

had some of the sensitivities in Rev 3, but there were still open RAIs at the time we wrote Rev 3.

MEMBER BLEY: Oh, okay.

MR. WACHOWIAK: And I think a couple of these other sensitivities -- but I think they are more building-related sensitivities are in the -- in the RAIs.

MEMBER CORRADINI: I don't think we dwelled -- I think we're going to have to move on, but I don't think we dwelled on it as much as knowing that the responses are on their way to coming or have come. So --

MR. WACHOWIAK: Yes. For the -- there are some four open items yet in shutdown event, in the details of how those are modeled. Two of the answers are -- have been responded to. Matter of fact, I think the letters came out today, and we are still working on the other two issues. So those -- we looked -- it looks like we're on a path to resolution for those.

And then, in the severe accident area, we have I believe 21 documented questions on the BiMAC right now. Is that not right?

MR. HAMZEHEE: 28.

MR. WACHOWIAK: 28 questions on BiMAC.

That's our most significant area to answer. Those --

MEMBER CORRADINI: We're just very curious.

MR. WACHOWIAK: And the reason that those -- there's those that are left out is the BiMAC test report is a recent submittal to the staff, and we're getting to that point in the review right now. So those are all under development and don't have any reason to expect why they would be -- or would miss the scheduled dates for that. So that's in the PRA area.

Now, I want to get into RTNSS briefly, because this is some --

MEMBER CORRADINI: Very briefly.

MR. WACHOWIAK: I have the different ways that things can become RTNSS. The top two -- A and B -- are deterministic. C and D -- C is definitely a probabilistic thing. D is somewhat probabilistic, somewhat deterministic. And then, E is another deterministic thing, where -- so everybody thinks that RTNSS is all probabilistic stuff, where you find the important equipment and you put it in this program. Most of the ways to get something in the RTNSS is deterministic and are associated with other issues, other things.

The main thing that we focus on in RTNSS with the staff are the quality levels for the Class B and what we call Class C RTNSS equipment. So those are there. You can read those.

The design treatment, which is basically what do you do with the RTNSS equipment once you've identified it, we have certain design requirements for these. These are in our design specifications, and there is some description of this in the BCE as well.

If it's active components that you're looking for in this, we have redundant active components. So if we have a RTNSS function, we'll have redundant active components, which means we can share passive components like buildings, pipes, tanks, things like that.

The RTNSS equipment needs to be fire- and flood-protected. So where you might have a non-safety-related component that used to be combined with other things in a single flood area, what we've identified is that there needs to be some flood protection for these things.

Hurricane Category 5 missile protection is what we're looking at there. This -- so if it's in a building -- if it's in -- what's that? You want me to go back? Okay.

MEMBER CORRADINI: He reads slowly. He has a quick question.

MEMBER APOSTOLAKIS: C.

MR. WACHOWIAK: C.

MEMBER APOSTOLAKIS: I thought that under -- the components that you needed, you need the Commission -- they were automatically safety-related.

MR. WACHOWIAK: No.

MEMBER APOSTOLAKIS: No?

MR. HAMZEHEE: I'm sorry. What was the question, George?

MEMBER APOSTOLAKIS: The focused PRA says do a PRA only with safety-related SSCs, and show that you meet the goals, right? You have to meet the goals --

MR. HAMZEHEE: Yes.

MEMBER APOSTOLAKIS: -- with the safety-related.

MR. WACHOWIAK: No. It's --

MR. HAMZEHEE: It's not safety-related. It says that, first, do your PRAs without the RTNSS systems and see --

MEMBER APOSTOLAKIS: No, forget about the RTNSS. Is it true that if you need something to meet the Commission goals, it becomes safety-related?

MR. HAMZEHEE: Not necessarily, because Rick had the existing PRAs and the PRA safety goals. They take credit for safety systems as well as non-safety systems.

CHAIRMAN SHACK: No, no. But this is for advanced reactors. Clearly, that's not true for current reactors.

MR. WACHOWIAK: The way that this is -- was set up is you do the focused PRA with only the safety-related components.

MEMBER APOSTOLAKIS: Right.

MR. WACHOWIAK: Okay? If you meet the Commission's safety goals with only the safety-related components, then you are done. If you don't, then you add non-safety components until you do meet the goals, and all of those non-safety components must be RTNSS. That's what C is.

MR. HAMZEHEE: I think that he is mostly -- yes, he is correct.

CHAIRMAN SHACK: The answer is that you have regulatory control over all equipment needed to meet --

MR. HAMZEHEE: Because I think that -- remember, George, the purpose of RTNSS is to make sure that those systems that are not safety-related, but are important to safety, are being taken credit, that the risk assessments are going to go through some regulatory treatment, so that they don't become unavailable when they are needed. That's really the purpose. And to ensure that those components are captured, then we do two or three different PRA analysis under C category to capture all those components and systems.

MEMBER APOSTOLAKIS: So how do you determine safety-related? Through some other method?

MR. HAMZEHEE: Chapter 15. There is a Chapter 15 analysis that anything you take credit for in your design basis accidents by definition are --

MEMBER APOSTOLAKIS: They're deterministic.

MR. WACHOWIAK: Correct.

MEMBER APOSTOLAKIS: Sorry. I wasn't there.

PARTICIPANT: I knew you weren't.

MR. WACHOWIAK: Our stuff is actually in Chapter 6.

So what some of -- what our treatment that we have here -- this is our design treatment, and then regulatory -- these things could be -- would be inspected, designed for the environment they're in.

We use quality suppliers. They don't have to be Appendix B suppliers, but they do have to have a quality program; ISO 9001 are examples for -- given in the SRP.

For the RTNSS B functions, the things that are required to achieve or maintain safe shutdown following 72 hours, we have made those seismic Category 2. For other RTNSS functions, they don't necessarily have a specific seismic category.

We do use technical specifications for components that are needed to meet the CDF and LERF goals, and it's not quite as simple as saying the things that you put in RTNSS C go into tech specs. There is a description in there where we added things into RTNSS.

And then, to determine if it needed technical specifications, we did an importance on those things that we added. If they turned out to be important, and the criterion is in the report, then it would have technical specifications. The diverse -- many of the functions of the diverse protection system or diverse digital I&C system ended up in tech specs.

For everything else, it's addressed in what we call the availability controls manual. It looks like tech specs, but it's not. But it's for non-safety components, and it's there to assure that the plant is controlling the availability of the other RTNSS components.

I say here for front-line systems it's because the way we treat support systems in the ACM is that their availability is tied to the front line systems, so that they don't explicitly cull out the support systems.

MEMBER ABDEL-KHALIK: Just an order of magnitude, how many SSCs are there in the RTNSS C category?

MR. WACHOWIAK: A lot.

(Laughter.)

MEMBER ABDEL-KHALIK: It's alarming.

PARTICIPANT: C?

MEMBER ABDEL-KHALIK: C, yes.

MEMBER APOSTOLAKIS: You mean the probabilistic.

MEMBER ABDEL-KHALIK: Right.

MR. WACHOWIAK: Probabilistic. And the reason that it came out that way is associated with how we put the support systems for the plant together. So the system that we wanted to have in RTNSS for C, to address the goals, is the fuel and aux pool cooling system. So it acts like a suppression pool cooling and LPCI system, as an active system for our plant.

That's the system that we needed to have in RTNSS. But that system needs closed cooling water, it needs HVAC, it needs instrumentation, it needs electricity, it needs service water. It needs all the different support systems.

So once we say we want to use that particular system, by definition we drag in all the support systems that are needed to run that particular system.

MEMBER APOSTOLAKIS: And a related question is: how many of the safety-related SSCs will end up being not risk significant? You're not going to do that, but I -- somebody in the future might do it.

MR. WACHOWIAK: That's a different --

MEMBER APOSTOLAKIS: That's a very high percentage.

MR. WACHOWIAK: That's a different question completely.

MEMBER APOSTOLAKIS: Completely.

MR. WACHOWIAK: And it would be -- it would be nice to do that, to see if we could move some things out of safety-related. But in this particular plant, there is really not that many safety-related components, because of the -- there's safety-related structures, but not a lot of safety-related components.

MEMBER APOSTOLAKIS: But did you say that once you decide to use it on a system you bring all these other systems -- don't the deterministic requirements --

MR. WACHOWIAK: For the active systems. For the passive systems, remember, you have a valve, you've got the I&C system, you've got a battery. There's not really a lot of components there.

So for ESBWR, going through that exercise may not get us much in terms of reduction.

MEMBER CORRADINI: We're going to have to have the staff, so I --

MR. HAMZEHEE: Mark has some statistical --

MR. CARUSO: Yes, this is Mark Caruso. I just thought I'd try to be helpful on this question about how many were in C, because there's a handy-dandy list that is in the DCD, and I just happen to have it with me. So I counted them, and there's 22.

MR. WACHOWIAK: Systems.

MR. CARUSO: I don't know if I -- I mean, there's -- it somewhere between -- I mean, it's MSIVs, it's valves, it's systems, it's -- this is a list of 22 things, some of which are components, some of which may be --

MR. WACHOWIAK: They're systems.

MR. CARUSO: 22 particular SSCs that contribute to satisfying certain functions from that category.

MEMBER APOSTOLAKIS: Do you always carry that with you, Mark?

(Laughter.)

MR. CARUSO: Only when I come and visit with the Committee.

MEMBER CORRADINI: Keep on going, please. We need to --

MR. WACHOWIAK: So we do have some open items left in the RTNSS area. On availability controls, what should be in the manual versus what shouldn't be in the manual. And there are some specific questions on that. And I think Hossein is going to cover these in more detail in his presentation, so I won't dwell on them here. I'll just say there are some open issues for how we put that in there.

We had a question before on the design standards for the RTNSS B or the post-72-hour functions. We think that that's a resolved issue now with our latest set of RAIs on that issue.

The augmented design protection, design standards for flood protection, we -- the staff went back and looked at those RAIs. We think that that's a resolved issue now, even though it may have been listed as an open item before.

And then, the status -- RTNSS status of some of the active systems that -- there are some questions about those, and we've got responses in development for those.

Conclusions -- here we go, get me off of here. We think that the ESBWR chapters on this area met the requirements for the certifications. There is very limited open items that need to be resolved, and for those we are pretty much at a -- on a path to resolution on these.

And the review that we've had, and RAIs, and questions/answers, audits, the whole body of things -- of things that we have done I think will confirm that we have met the required objectives with our set of PRA documentation.

MEMBER CORRADINI: Thank you.

MR. WACHOWIAK: All right.

MEMBER ABDEL-KHALIK: Does it give you

pause that there are 22 RTNSS C systems that can push your CDF from about 10^{-8} to greater than 10^{-4}.

MR. WACHOWIAK: We weren't limited by the 10^{-4} criteria. It's the LERF of 10^{-6}.

MEMBER ABDEL-KHALIK: Well, okay.

MR. WACHOWIAK: So it's -- there are things that are backups that end up pushing us over 10^{-6} for CDF cases where there is no containment.

MEMBER ABDEL-KHALIK: But, again, you know, it would push you from 10^{-9} LERF to the minus -- to greater than 10^{-6}. Doesn't it bother you design-wise?

MR. WACHOWIAK: No. Because in a -- in nuclear powerplants, we use a combination of safety-related and non-safety-related equipment to affect the overall risk significance. And there is no reason to believe that only safety-related functions in the ESBWR would be sufficient to drive the core damage frequency and release frequency down into very low ranges.

Remember, deterministically, the safety-related case just shows you have -- just requires you to be one redundant component deep to meet all of the safety functions. And it doesn't even need to be a diverse component to do that. It just needs to be redundant.

So following the rules for what makes things safety-related, I would be surprised if you didn't need anything non-safety-related to meet all of those goals, especially on the LERF side, since that's a fairly low number as well.

MEMBER ABDEL-KHALIK: I understand conceptually. But what surprises me is the magnitude of the change, given the difference --

MR. WACHOWIAK: Three orders of magnitude sounds about right for an active system for me. The reliability of an active system, dual-train active system, tends to be about -- or unreliability tends to be about .001. That's -- so if you -- you pull out some of the ones that we have, the CDF would go up by about that much. And we have other active systems that we didn't count in to RTNSS, so it's the -- it's the reliability of those systems that are being pulled out of the mix.

MEMBER MAYNARD: Is the biggest impact on the shutdown sequences there, while you're shut down, or is it while you're operating?

MR. WACHOWIAK: Those are while we're operating. The -- we took a look at the initiators for shutdown to see if there was anything else that needed to be added from RTNSS, and we didn't have any there. And the rules that were agreed on for the focused PRA, I remember that they were done using the full power PRA, instructions in the agreement, in the SECY.

So, but remember, these components that are supporting the things needed for shutdown -- as we said, we've got 22 of those functions. Most of them are in there already, and they have performed those functions. The system -- front line system that we picked, the FAPCS, is also used as a system in the shutdown as well.

And it's also -- and for the spent fuel pool. That's mainly why -- the main reason we picked that system, was because -- one of the reasons was because it not only protected the core, but it also could be used to protect the spent fuel pool. So we thought it was a good system to put into the pre-treatment.

MEMBER CORRADINI: Other questions for Rick?

(No response.)

Okay.

MEMBER APOSTOLAKIS: There is a big question in my mind, but I don't know that he can answer it.

MEMBER CORRADINI: Can we wait until we have the staff up there?

MEMBER APOSTOLAKIS: Oh, we can wait. We will never get the answer, so --

MEMBER CORRADINI: So I'll thank you for the moment. Don't --

CHAIRMAN SHACK: Let's finish the presentations, then, first.

MEMBER CORRADINI: Let's don't go far, then. And I'll ask the staff to --

MR. WACHOWIAK: I need an escort to go farther than the door anyway.

(Laughter.)

MEMBER CORRADINI: So then we won't give you an escort for a while, good.

MR. WACHOWIAK: I'll be here.

MEMBER CORRADINI: Thank you.

MR. HAMZEHEE: I think now we have three people from the NRC staff that are going to give you a summary of what we already presented to the subcommittees in the last few months. And we have Mark Caruso, who has the lead for the review of the PRA, we have Marie Pohida, who has the lead for shutdown portion of the PRA, and then Ed Fuller, who is responsible for Level 2 and severe accidents.

MEMBER CORRADINI: So who is going to kick off? Mark is going to kick off?

MR. HAMZEHEE: Mark is going to take the lead, yes.

MR. CARUSO: Okay. As Hossein said, our purpose here is to brief the Committee on the status of our review. The crux of it is really focused on the open items. So if you want to -- if you want to cut right to the open items, we can get to that. I just have a few introductory slides before that.

Slide 3 shows the folks that were involved in the review of Chapter 19. Myself focused mostly on the Level 1. I'm sort of overall coordinator. Ed Fuller here on my left worked -- go to 6? Ed worked on severe accidents. He is our shutdown expert. John Lai, who is here, worked on fire; and Glenn Kelly worked on high winds.

Objectives of the staff's review --

CHAIRMAN SHACK: And your structural engineer does seismic margins?

MR. CARUSO: Jimmy Xu is here. He is not --

(Laughter.)

Our objectives are the Commission's

objectives, and they were also GE's objectives. So we're all -- we're all on the same page, and I think Rick went through these.

MEMBER APOSTOLAKIS: Is that a coincidence?

MR. CARUSO: No, it's not. Not at all. Not at all.

Okay. So --

MEMBER APOSTOLAKIS: Can we see those?

MR. CARUSO: Yes. They look very familiar. We have a different order, though. I'm already on the next slide.

MEMBER APOSTOLAKIS: Oh, okay.

MR. CARUSO: I'm on the next slide.

Areas of review with open items. We have a few open items left, as Rick mentioned, and they fall in these areas -- in the PRA quality area, there's seismic margins, high winds, shutdown on power operations, and the severe accident area.

So the next slide in the quality area, and we've actually beat this one I think quite a bit today, the issue -- as Rick said, we had -- we have gotten the DCD Rev 4, and there wasn't much in there about what they had done to sort of assure quality, a level -- some level of quality for the design PRA.

And as Rick said, there really -- there is no regulation here, there is guidance that says an internal level review on the part of the vendor is sufficient. We didn't know what they had done. They had said that they had attempted to try and meet as many capability Category 2 attributes as they could. So we asked them to describe in detail what they had done, which prompted them to do a little bit more formal in-house sort of self-assessment peer review.

They have done that. They submitted the results and RAI response. They did a systematic look at the standard, comparing what they had done with the standards with the capability Category 2 attributes. They identified which of the attributes they felt did not apply to the design PRA, which were -- mostly had to do with things that are plant-specific, procedural stuff, things that, you know, are hard to capture now at this stage.

And then, they identified the few areas where they didn't meet the Category 2, and explained why there was small impact. We were satisfied with their response, but I believe you'd have to say that after our discussion with the subcommittee that there are questions about the effectiveness of what was done.

So we're -- you know, our follow up -- the next step closure on this is for our follow up onsite at GE to take a close look at Rev 3 and make sure that -- that the Rev 3 is robust. So we're going to go there in November and look at the PRA.

When we spoke to the subcommittee in June, the other item that was on this slide was on the success criteria for passive systems, and we had an RAI asking GE to give us some more confidence that the analysis techniques they had used to justify the success criteria that they had selected for passive systems was robust. And they have since done that.

They, in fact, presented that to the subcommittee in August, and we all listened, and we're fairly satisfied with that. So --

MEMBER ABDEL-KHALIK: Now, this dealt primarily of, you know, how many of which widget would you need.

MR. CARUSO: Right.

MEMBER ABDEL-KHALIK: But there are some other things that were sort of pushed into ITAAC category, like tilt of pipes to make sure that gas accumulation doesn't happen. How do you capture errors in that process in your PRA space?

MR. CARUSO: Well, I don't know about

tilted pipes, but, I mean, things like errors in pipe diameters, friction factors, heat transfer coefficients and condenser tubes, all those things are factored into a thermal hydraulic calculation. The things that are not factored into a thermal hydraulic calculation, you know, if they're important, then that's a problem.

But I think, you know, that particular issue on gas is -- you know, it's -- in terms of non-condensables and, you know, the I&C system, the passive containment cooling system, you know, those are treated in the thermal hydraulic analysis.

Now, gas accumulation in ECCS systems, I know an operating plant is not treated very well in PRAs. And so, you know, those kinds of issues -- I mean, a lot of those issues are being looked at in the design reviews. I mean, gas accumulation in ECCS systems is a design issue. It's hard to capture in PRAs. I mean, if you have, you know, things -- you have events and --

MS. CUBBAGE: I think you hit the nail on the head when you mentioned -- when you say "pushed to ITAAC," actually I would say -- contrary, I would say, you know, it's going to be verified by ITAAC that it has been installed as designed. And then, the design is what's modeled in the PRA. So the assumptions of the PRA are validated by the ITAAC verification. You have to make certain design assumptions when you make a PRA.

MR. CARUSO: Well, the PRA does its best to capture the design and model the design and capture the phenomena in terms of barriers. And then, the ITAAC process is to ensure that the design -- the as-built plant recent design, so it's --

MS. CUBBAGE: Right. In fact, the selection --

MR. CARUSO: -- sort of a cascade.

MS. CUBBAGE: The selection criteria for what is included in ITAAC does have a component verifying the significant assumptions in the PRA.

MEMBER ABDEL-KHALIK: Thank you.

MR. CARUSO: Yes. Now, I do know that in one sense in the PCC that there -- you know, in the PRA there is an assumption that you will always get gas up there. And there is in the model -- it is treated in the model that if the gas vents -- if the vents for non-condensables don't work, you fail it.

So there's no probability of will you not get gas or get gas. It always assumes that there's gas, but it assumes that the system will work as designed, which is the vents will open and it will vent if you don't get rid of the gas. So in that particular system, I think they are on pretty good ground.

All right. Slide 8, the open issue on seismic margins analysis. I think Rick went over this one, too, in some detail, which is we had questioned their choice -- their use of a spectrum shape different than the certified design response spectrum. And we are still waiting for their response on that.

Slide 9 is in the high winds area. These are just some questions -- outstanding questions on their assessment that Rick also went through. And I don't have much more to say on these. We are waiting for their -- for their responses.

Slide 10 is the open items on shutdown and operational modes, and Marie is going to go through these for us.

MS. POHIDA: Okay. Thank you.

The first one has to do with a diverse protection system. Okay? And this has to do with assessing breaks outside of containment. Breaks outside of containment were not quantitatively analyzed. Okay? And in the PRA, GE states that they weren't analyzed because you had the safety-related leakage detection system that will be operable, you know, as directed by tech specs, and the non-safety-related leakage detection system will be available.

But when you go review tech specs, the non-safety-related leakage detection system is not required to be operable in tech specs. So what we're asking GE to do is to either consider adding the operability of these non-safety-related systems in Modes 5 and 6, or to go back and assess the risk of RWCU breaks and operator-induced leaks outside of containment. So that's open item number 1.

Okay. Open item number 2 has to do with operator-induced leaks. In general, they were not quantitatively analyzed in the PRA. GE's position was that operator-induced leaks downstream of the containment isolation valves and the RWCU system would effectively mitigate those types of losses.

What we're concerned about is what's going on upstream of the containment isolation valves. What are the sizes of piping penetrations? What are the associated alarms and position indication? That if the operator were to have -- induce a leak in these piping penetrations, what would happen to the system? Is it something that we need to be concerned with? So that's open item number 2.

Open item number 3 has to do with the isolation condensers. The isolation condensers at shutdown are very risk significant. They significantly reduce the loss of RHR events from internal events and external events during Mode 5, okay?

And what we're concerned about is, are there going to be some regimes during Mode 5 operation from which the isolation condensers will not function? And what we're concerned about is levels being raised to remove the head. And once that IC inlet sub-tube gets flooded, will the ICs be able to work? So we have some RAIs on that to GE.

We are also concerned about -- since the isolation condensers are credited with working from a loss of RHR initiating from Mode 5 conditions, how does the venting process work? You know, when are the vent valves supposed to open? Are there any special conditions, you know, involved -- in Mode 5 that would not be necessarily bounded by Mode 1 conditions? So that's open item number 3.

Open item number 4, on Slide 11, this is an RAI that we've developed with Reactor Systems Branch. And what we need more information on is the range of conditions -- and that is both temperature and level -- for which the RWCU system can adequately remove decay heat in Modes 4, 5, and 6.

And what we're concerned about is adequate vessel circulation from inside the shroud and outside the shroud, and we are still looking for information about, what is that minimum level? What is that, you know, minimum vessel level to assure, you know, adequate circulation between what's in the shroud and what's outside the shroud?

And what we're also concerned about is that RWCU injection, it may bypass the core, and we're concerned that there might be inadequate mixing in the downcomer. So that's --

MR. HAMZEHEE: Marie, which one -- are we also planning to do some in-house confirmatory analysis?

MS. POHIDA: On the isolation condensers. What we have asked the Office of Research to assist us with is, given various vessel levels in the core, to provide some confirmatory calculations that the ICs will work, initiating from a Mode 5 condition.

CHAIRMAN SHACK: Okay. GE already assumes that.

MS. POHIDA: They assume that. We have asked for confirmatory calculations. We didn't receive any. Their contention was that this operation is bounded by Mode 1 conditions, and we need some calculations just to confirm that.

The total LERF risk in this design is primarily driven by events at shutdown. You know, 74 percent of the total LERF risk is driven by external events at shutdown, with another, you know, portion driven by internal events. So, you know, functionality of the ICs is important.

MR. CARUSO: This is a little like, you know, the idea -- I think what we've been told is, well, you'll use RHR, and you'll lose the first system you have, and so the system would just go from heat up from low pressure all the way up to 1087, and then go right back to Mode 1 and you'll be a boiling water reactor, and the system will come on and just work.

And it's a little like your BiMAC question, which is that you've told me not to worry when I get to the steady-state condition where I am removing heat. And I -- if you get there, I believe the isolation condenser will do its job. But, you know, is it -- you can, convince us that you're going to -- this is all going to happen without any operators doing whatever they do.

We feel a little uncomfortable that we

don't have that sort of like sequence of analysis that takes you from Mode 5, what I meant -- you know, less than 200 degrees and low pressure, all the way back up. I mean, it's kind of like the same way in PWR, steam generators, you know, the shutdown strategy -- the shutdown strategy of -- I knew you were in 5, but if I keep my generators full of water and ready to go, I can just go back up to Mode 4 and get on the generators.

We don't have a lot of analysis here, any analysis here that -- in this. You know, shutdown is not a design basis. Anyway --

MS. POHIDA: So while we're waiting for responses, we have asked the Office of Research to help us to provide confirmatory calculations.

MR. HAMZEHEE: John has a question.

MEMBER STETKAR: Marie?

MS. POHIDA: Yes.

MEMBER STETKAR: I have to admit complete ignorance about the shutdown PRA.

MS. POHIDA: Okay.

MEMBER STETKAR: So maybe you can ask a quick -- answer a quick one for me. And I haven't asked GE this.

How did they treat -- I see how they

parsed things up into the different operating modes --

MS. POHIDA: Yes.

MEMBER STETKAR: -- according to the tech specs. How did they treat typical equipment unavailabilities during shutdown? You know, outage unavailabilities of equipment, stuff that is out of service for maintenance, for example. That's one of the big challenges of doing a shutdown risk assessment. Did they assume that everything was normally available?

MS. POHIDA: There's two parts. There are systems that are required to be operable according to tech specs.

MEMBER STETKAR: Okay.

MS. POHIDA: Okay. So, of course, that was handled as --

MEMBER STETKAR: Sure, sure.

MS. POHIDA: -- being available. Those include the isolation condensers, the DPVs that are needed for gravity injection to work, and things associated with the gravity injection system. Okay?

The non-safety-related systems were also credited as being available and functional in the shutdown PRA. We did ask GE for --

MEMBER STETKAR: Except for forced

maintenance unavailability, you know, repair of a pump failure or stuff like that, the standard --

MS. POHIDA: I need to go back and check. What we --

MEMBER STETKAR: Okay.

MS. POHIDA: What we do is -- this is my, you know, third advanced -- you know, advanced reactor review. We ask for sensitivity studies saying if -- if a licensee were to choose to adhere to minimal compliance to tech specs, what would the increase in risk be? Just to make sure there is no --

MEMBER STETKAR: Well, minimal compliance to tech -- okay, minimal compliance to tech specs.

MS. POHIDA: In other words, is -- you know, if --

MEMBER STETKAR: Assuming that all non-tech spec required equipment is out of service, you mean?

MS. POHIDA: That is correct. And also, you know, for example, if they -- the DPV valves. If there are eight and only four required to be operable, what happens to the rest? That's a sensitivity study that we do.

MEMBER STETKAR: They've done that?

MS. POHIDA: Yes.

MEMBER STETKAR: Okay.

MR. CARUSO: We are also raising this question on the COLs by saying, you know, we are --

MEMBER STETKAR: It is really important. We're saying -- you're referencing in a doctrine the design PRA, but is there something about the way you do shutdown, the way you take systems out of service, that might be outside what was in the PRA. So --

MR. CARUSO: Typically, shutdown risk is dominated not -- not necessarily how the plant is designed. It's how people do business.

MR. HAMZEHEE: It is configuration-specific.

MEMBER STETKAR: It is configuration-specific, and that's how people manage their outages, which is not --

MEMBER MAYNARD: Most of the current plants today during shutdown, you do credit non-safety equipment. You have controls in place to make sure that that's available, if you're crediting that.

MEMBER STETKAR: Right. That's the reason I was asking.

MEMBER MAYNARD: Yes.

MEMBER STETKAR: Go on. I'm sorry.

MS. POHIDA: Oh, that's it. That's my

four open items.

MR. WACHOWIAK: This is Rick Wachowiak from GE. To get back to your question, we also have to remember with this plant there is really no reason to put those maintenance activities for the non-safety systems into the shutdown.

MEMBER STETKAR: That's true. But don't dig yourself a hole, because I'm going to ask you how you counted the planned maintenance during power operations.

MR. WACHOWIAK: Right.

MR. CARUSO: All right. If there's no questions for Marie, we'll move on to the severe accident mitigation area. And Ed is going to go through the few open items we have there.

MR. FULLER: Basically, at this juncture, it has come down to two significant open items. The first one has to do with the performance of the BiMAC. And in this one, to give you a little background, leading up to the time when we went to visit the test facility a year ago, we had some open RAIs pertaining to whatever the test program might be.

We had asked GE to provide that information to us, so that by the time we got to Santa Barbara that we would at least have some feeling for what we were looking at. And that event came and went without the questions being adequately answered. However, shortly thereafter, they produced a test report, which we received in the springtime of this year.

And the test report came in as a topical report, and so we had to review it as a topical report, and, in so doing, generated 20-some-odd RAIs, 27 RAIs.

I would say they came into the five basic areas. Some pertained to the adequacy of the facility scale for applicability to the ESBWR configuration. And some questions related to the range of measured test data compared with what one would expect during severe accident loadings.

And we had concerns about the adequacy of the theoretical predictions as compared to the data, and we had quite a few questions pertaining to the implications of their design on ESBWR operational safety and how the tests might address those. And some of the RAIs were just simply for clarification and additional design details.

We presented -- made this presentation to the subcommittee in August, and by and large the questions that were raised have been subsumed already in the RAIs that we had prepared, except for one significant question. We forgot to ask GE to provide basically how one would get from the time of vessel breach, if you will, until when the BiMAC would be operating in a steady state, you know, as it was designed to operate.

So what happened when you got from here to there? So since then we have -- we have prepared that RAI and sent it to GE. And so now we have 28 RAIs, none of which have been responded to as of today.

MEMBER CORRADINI: I had a question, if I might, for you. Rick said something -- instead of going and getting details, I guess I'd ask the staff -- so if I understand correctly, there was a request about an analysis that in the absence of the BiMAC would -- would the design essentially be equivalent to the ABWR in terms of how it attended to the severe accident management scheme?

And I thought I heard you say -- and I guess I'll address this to Rick -- that you sent something to staff about an analysis in the absence of the BiMAC.

MR. WACHOWIAK: This is Rick Wachowiak. Yes.

MEMBER CORRADINI: So did I miss it? Did

you guys pass this on to us, or did I just forget to ask, since the August meeting? Because I think in the August timeframe it was in preparation, and it hadn't -- or did I misunderstand?

MR. WACHOWIAK: You misunderstood. That was sent some time -- oh, I'm trying to remember which trailer my office was in when we sent that to get a gauge of the time. But it was more than a year ago when we sent this in.

MEMBER CORRADINI: Oh, excuse me. So I guess just for a matter of -- just in order to understand it, I'd like to see that analysis, so that the subcommittee can just see. So just to do a comparison point. Because as you -- as Rick answered, you view BiMAC as a defense-in-depth measure, which means in its absence I ought to see similar behavior in this design. I'd like to just look through that if I could.

CHAIRMAN SHACK: That seems peculiar, because at that time, I mean, you still hadn't settled on the top material in the BiMAC. Even at the last meeting you were -- you know, you were changing the design of that. So, you know, the ablating material -- I'm not sure how you could demonstrate that it was equivalent to the ABWR. Yes, I know you said you weren't convinced it was going to be low -- you know, low-gas concrete at that time.

MR. WACHOWIAK: What we did in that sensitivity was we assumed that the BiMAC and its coating material would be --

CHAIRMAN SHACK: Gone.

MR. WACHOWIAK: -- gone. And we did the calculation with both limestone and the low-gas concrete. So the results that were presented to the staff were both sets of results.

CHAIRMAN SHACK: Just for that portion of the base mat, then, below the BiMAC.

MR. WACHOWIAK: Yes.

MEMBER CORRADINI: So it's as if the BiMAC weren't in existence is the way you did the analysis.

MR. WACHOWIAK: That's the way we did the analysis.

MEMBER CORRADINI: Let me ask one last question, just to -- so I get a frame, because we'll get the memo. Was it -- well, first of all, was it a topical report by you all, or a memo to staff?

MR. FULLER: It was a response to the RAI.

MEMBER CORRADINI: Oh, an RAI. Excuse me. Is the square footage in the lower pit, cavity, whatever you call this thing below the vessel, meet the utility design --

MR. WACHOWIAK: The URD spreading criteria?

MEMBER CORRADINI: Yes. Thank you.

MR. WACHOWIAK: Yes.

MEMBER CORRADINI: Okay.

MR. FULLER: Okay. Are there any other questions on the BiMAC open item?

(No response.)

Okay. The second one has to do with the process of developing severe accident management guidelines. And we have been asking questions all along, how they were going to do this, and kept that -- creating supplements as we got answers that didn't quite get to what we thought the question was.

And, finally, in the spring we got -- we got additional information on the process that they would be using to develop the guidelines. However, we have also been asking for what we would be calling the technical basis for severe accident management for the ESBWR, recognizing that we've got a very -- a design which has quite a few significant differences from the existing BWR fleet.

And so we would expect that -- that certain phenomena would unfold in different timeframes, and other phenomena that you might not have been -- that were expected in existing BWRs may not arise in the ESBWR.

So we wanted to see how GE was putting together the information from their severe accident analyses and Level 2 analyses to present to the COL applicants, so that the applicants could go ahead and develop their procedures and training, etcetera.

So this technical basis generally takes the form of candidate actions, high-level actions, strategies, and relationships to the timing of the phenomena. And that's what we're asking for, and at this point we're awaiting the response to that particular request.

MEMBER CORRADINI: So can I understand what this means? I guess I'm listening to you describe it. I'm not sure if I completely appreciate it.

So are you saying, for example -- I'll give you for example, and you tell me if I'm off base. For example, what's the basis in which the BiMAC -- what's the -- I'll use the BiMAC, just to stick with one topic. What's the operational -- not the operational condition, but what is the acceptability criteria for the BiMAC operation?

MR. FULLER: No. That's not what we're looking for.

MEMBER CORRADINI: Okay. So --

MR. FULLER: Let me get --

MEMBER CORRADINI: Yes.

MR. FULLER: What is your -- an example, what is -- for example, what is your strategy for preventing vessel breach? What is your strategy for assuring debris coolability for X number of hours? What is your strategy for preventing containment failure for X number of hours, whether it be 24 or 72, or whatever their guidelines might come up with?

So what is your strategy? What are the -- the high level type actions that you would be taking to carry out these intentions?

MEMBER CORRADINI: So these are more severe accident procedural guidelines for various objectives.

MR. FULLER: Yes.

MEMBER CORRADINI: Okay. All right.

MR. FULLER: They are guidelines to develop the procedures.

MEMBER CORRADINI: Okay. Thank you.

MR. FULLER: Okay?

MEMBER ARMIJO: When do you line up fire

water?

MEMBER CORRADINI: Okay. Thank you.

MEMBER ARMIJO: And why?

MR. FULLER: Okay. Anybody else on this?

(No response.)

Okay.

MR. CARUSO: Okay. Let's move on to Chapter 22, which is regulatory treatment of non-safety systems. Format here is the same. The objectives of the staff review went through sort of the RTNSS in a nutshell, which is what -- what stuff is in scope? Did they get that right?

For the active systems, have they identified the reliability and availability issues consistent with what PRA assumes? Are those two consistent? And when they have identified treatment for those active systems, does it make sense? Is the treatment consistent with what the reliability -- reliability and availability issues?

We just have a few open items left in this area. There has been a lot of work done in this area by GE since we met with the subcommittee. The biggest issue I think we had back in June in this area had to do with the Category B items, which are the items -- this is a deterministic category, which, you know, how do I ensure safety functions for containment -- or for control room habitability?

In that period beyond the 72 hours -- you know, the passive systems will work for 72 hours with hands off, and then at that point you've got to do some stuff. You've got to use your non-safety systems to refill tanks and do other things.

And the biggest problem we had was that a lot of the equipment that they were relying on to take care of those functions was housed in buildings which were meeting National Building Code standards. They weren't even meeting seismic Category 2. And our structural people had a big problem with this, and we pretty much felt it was outside what the Commission had sort of scoped out in their policy papers and stuff.

Well, since that time, there was a lot of thinking that went on about how to treat these Category B functions, and GE made a number of changes. They incorporated some additional diesel generators in seismic Category 2 buildings that would power a lot of stuff that they could use to take care of these things.

In a nutshell, they are now at a point where they need nothing -- nothing to satisfy the

Category B functions that's in a building other than seismic Category 2 or seismic Category 1. So all of the issues that we had in that area are pretty much -- pretty much resolved.

So that's probably the biggest change since June. So what we're left with in this area is we still have one I would say minor issue in this area, which has to do with treatment of how you protect against flooding and missiles. And we are -- we've got to the point where we're happy with the response on, you know, that the design provisions that we -- the design specifications that they are going to incorporate are, you know, consistent with the standards and are good enough to do it.

That we understand what they're going to do and we believe it's good enough, and it's -- you know, it meets standards. But we want them to put in Tier 1 in an ITAAC something that makes sure that the as-built protections are consistent with what is in the design. So we have raised that with them. They haven't actually seen this one yet. This is --

(Laughter.)

We're happy with the reactors about the design, but we're not quite finished yet.

(Laughter.)

So that RAI has just gone out, so I -- so Rick has not -- so don't ask Rick anything about it, because he hasn't seen it yet.

And while we have -- just in the area of regulatory treatment, we had a couple of issues with -- that came out of a review of DCD Rev 5, and I'm going to be putting some -- putting the systems either -- either treating them with availability controls or simply relying on the controls that are inherent in the maintenance rule.

And the issue was we had systems and it was -- there was discussion in the DCD about, well, you know, we are basing this on the -- on the risk achievement worths and the Fussell-Vesely, and, you know, how important is it to risk. And so we looked at some of these systems. I think we're looking at the FAPCS compared to some of the -- just support systems -- turbine-building, closed cooling water, reactor building cooling water. And we're seeing the numbers to be identical.

And we're going -- well, why aren't these in the same category as these? So that's one question.

Another question has to do with the inclusion of FAPCS in RTNSS. There has been a -- sort of an addition I think to the FAPCS system, which is a -- there's a fire pump that's now being dedicated to low pressure injection. It's not being dedicated to fire any more. It is a fire pump, but it -- it takes suction from the fire tank. But it's dedicated to putting water in the vessel, and it's using the FAPCS piping.

And so it appears to be sort of a third FAPCS train, and it does -- we're not quite sure if it's in RTNSS or not. And if it's not, we're not quite sure why it's not. So we did ask these questions.

And the last issue we have is a number of -- these are some questions about the availability controls, and these questions -- we did discuss it with the subcommittee in June. They are still out there, and GE is preparing a response to these. These are just a number of issues that came up in our review of the availability controls manual -- a number of issues, the clarity of the controls as written, and some inconsistencies on the treatment in the controls compared to how systems were treated in the PRA.

For example, I think the controls -- there was a control that said, well, you only need to have one train of FAPCS available, and in the PRA they had assumed they had two trains. So they said, "Well, how does that compute?" So we're still waiting for answers in these areas. So that's pretty much it in the area of RTNSS.

I might want to say one other thing. Going back to that discussion at the end of Rick's presentation about the 22 items, I think, you know, when you look at this list, I think it's to note that most of those items are related to functions in the diverse protection system, which affect all kinds of stuff -- scram, MSIV closure, SRV actuation, bi-modal control rod actuation.

And these -- the reason that the DPS -- these functions are in there is that -- it has to do with the treatment of the common cause failure in the safety part of the digital protection system, and that this non-safety part is a backup to that. And so because of the -- you know, the assumptions, if you will, about common cause failure and software and stuff, the DPS is showing up as very important.

And so it is -- I guess my point is that it's not a whole lot of separate -- you know, I probably said valves and things like that. It's really the functions, the protective system functions, non-safety protected system functions, back up the safety functions for a lot of these things.

And so when you add up all those things, you get a large number. So it's -- the 22 I guess is probably a little bit misleading. I think there is -- you know, I thought I would shed some light on that.

Any questions based on that?

MR. WACHOWIAK: No. But that was a pretty good characterization. It -- I've got a couple of things on the RTNSS. The assumptions on the common cause for the digital I&C is what pushes a lot of things across the threshold. And the FAPCS in RTNSS -- basically, the focused PRA says you look at these things with point estimates, and then you also have to consider uncertainty for adding additional things.

The FAPCS system was added based on the uncertainty or the sensitivity analyses to address uncertainty. So that is why the third FAPCS pump didn't make it. We only needed the two FAPCS pumps to get us through the uncertainty issue. We didn't need to add the third train to get us past the uncertainty. It wasn't the mean values that got FAPCS in.

A couple other things that I want to clarify -- that one -- one is something where I may have led to something on the BiMAC, this separate calculation without the BiMAC, that in my mind it's clear, but I don't think it would be clear in yours right now. When we did this calculation, we didn't assume the -- we assumed that the BiMAC wasn't there, which is the pipes and the covering material.

There still is underlying structural concrete that has a shape to it. We considered that shape in the calculation. It wasn't a flat floor, like ABWR. The shape was considered. So when you see it, you'll tell that.

The other thing -- and -- well, I won't get into it now, because the -- we'd have to go to closed session. So -- but anyway, the shape was considered with the information we had at the time.

The other thing that came up here in the discussion of the open item for RTNSS, it's a historical thing, since we've changed some things, but I think Mark led you to believe that we didn't have seismic protection on things needs to refill pools and to keep the plant in the safe condition. And that is not the case.

The equipment needed to refill the pools and to keep the core covered was in seismic structures. It was the power to run the instrumentation for monitoring of level, pressure, and things like that, the monitoring parameters, that was not in the seismic structure at the time. We didn't have a way to power those, so it wasn't what was needed for core cooling or containment integrity that was non-seismic, but it was the post-accident monitoring function that was non-seismic. But that has all been fixed now.

We -- for other reasons, we added the generators, the new, smaller diesel generators, and when we did that we happened to find an easy way to address this monitoring open issue by just using those diesel generators to power the monitoring equipment.

MEMBER CORRADINI: Bill, you had a question?

CHAIRMAN SHACK: Well, there was just an issue that came up when we looked at the BiMAC in the subcommittee meeting that I didn't see addressed in Ed's discussion of the open items. And this was the crimping of the pipes by an explosion and whether that would inhibit the operation of the BiMAC.

MR. CARUSO: We asked if -- have you asked anything like that?

MR. FULLER: No.

MEMBER CORRADINI: Okay. Do you know what we're talking about? Do you want me to repeat what we had said at that time? I can --

CHAIRMAN SHACK: GE planning to address it to us at any rate. It's not --

MEMBER CORRADINI: Rick, do you remember the question?

MR. WACHOWIAK: Yes, and I think the way we answered it was is that's answered in our report. That's -- the steam explosion impulse/impact on the BiMAC pipes was one of the criteria for the BiMAC.

MEMBER CORRADINI: But I guess maybe I remember that it was still an open issue from the standpoint that I thought you addressed it in terms of dynamic loads on the piping that is buried, but not dynamic loads on the downcomer piping that is exposed within the water pool.

MR. WACHOWIAK: Okay. Yes, that's --

MEMBER CORRADINI: To put it -- let me put it differently. When you guys are in steady state mode, the water somehow has got to get back from the upper pool and flow down and things -- that means it has got to be an open -- some sort of way in which the water gets into the piping and comes down, which means the piping is exposed to the water pool where you say you continue to have melt coming in, which means if you have some sort of FCI that piping is exposed to any dynamic pressures. And I didn't see that analysis in the appendix of 34, something or other, 32.411.

MR. WACHOWIAK: Okay. A couple of things on that, and I think it is addressed in the report, but maybe not -- not explicitly for some of this.

Now, the lower pipes were considered, definitely --

MEMBER CORRADINI: Right.

MR. WACHOWIAK: -- in the steam explosion.

MEMBER CORRADINI: Right.

MR. WACHOWIAK: The vertical portions of the pipe were not considered in there, because they are covered with the -- at the time, the zirconium material, but now our floor material. So they are not going to be exposed to the impulse. There is intervening material there that is going to deflect that impulse. And if that's still a question about exactly how we can get -- we can get an answer to that -- that one.

Now, and there's a third set of pipes, it's the ones coming from upper -- the upper area down to fill the BiMAC. If the water is high enough to be in contact with those pipes, a significant part of those pipes, then, number one, we have already assumed that the containment is going to fail with a water pool that deep. So crimping the pipe is just --

MEMBER CORRADINI: I don't understand that. Can you say it again? I'm sorry.

MR. WACHOWIAK: Okay. If the water itself is significant depth within the lower drywell --

MEMBER CORRADINI: Right.

MR. WACHOWIAK: -- so let's say two meters deep --

MEMBER CORRADINI: Right.

MR. WACHOWIAK: -- we are already assuming that the containment is going to fail with a steam explosion from that depth of pool. So the containment failing and the BiMAC pipe crimping kind of subsume each other.

MEMBER CORRADINI: I missed that. That was in the appendix? I guess I missed that.

MR. WACHOWIAK: No, that's the one part where we -- we assume that the way it was designed would have handled that question. It's -- the question is explicitly on the table, what about those pipes?

And so for water pools, that's the one thing -- the pipe is not really going to be subject to that. The other thing is that we have answered in RAIs before that those pipes will be protected somehow from melt interacting with those pipes themselves, whether you put a shield on them or if you -- or if you do something like that. But part of the design criteria for those pipes is that they need to remain an open path in the environment where you have core material coming out of the vessel.

MEMBER CORRADINI: Okay.

MR. WACHOWIAK: So we expect some kind of -- in the detailed design some kind of shielding on those pipes.

MEMBER CORRADINI: Thank you.

Other questions?

(No response.)

Well, let me thank the staff and GEH and turn it back over to our Chairman, on time, on budget.

CHAIRMAN SHACK: We're 45 minutes behind schedule.

MEMBER CORRADINI: We started 20 minutes late.

MEMBER POWERS: Did that change the requirements on you?

MEMBER CORRADINI: No. It wasn't in my performance --

CHAIRMAN SHACK: Let's try to get back at 4:10.

(Whereupon, at 3:55 p.m., the proceedings in the foregoing matter went off the record.)

Harris Nuclear Plant

ACRS License Renewal Presentation

October 2, 2008

Shearon Harris Nuclear Plant License Renewal Representatives

- Mike Heath – License Renewal Supervisor
- Dave Corlett – Licensing/Regulatory Programs Supervisor
- Matt Denny – Equipment Performance Supervisor
- Chris Mallner – License Renewal Mechanical Lead

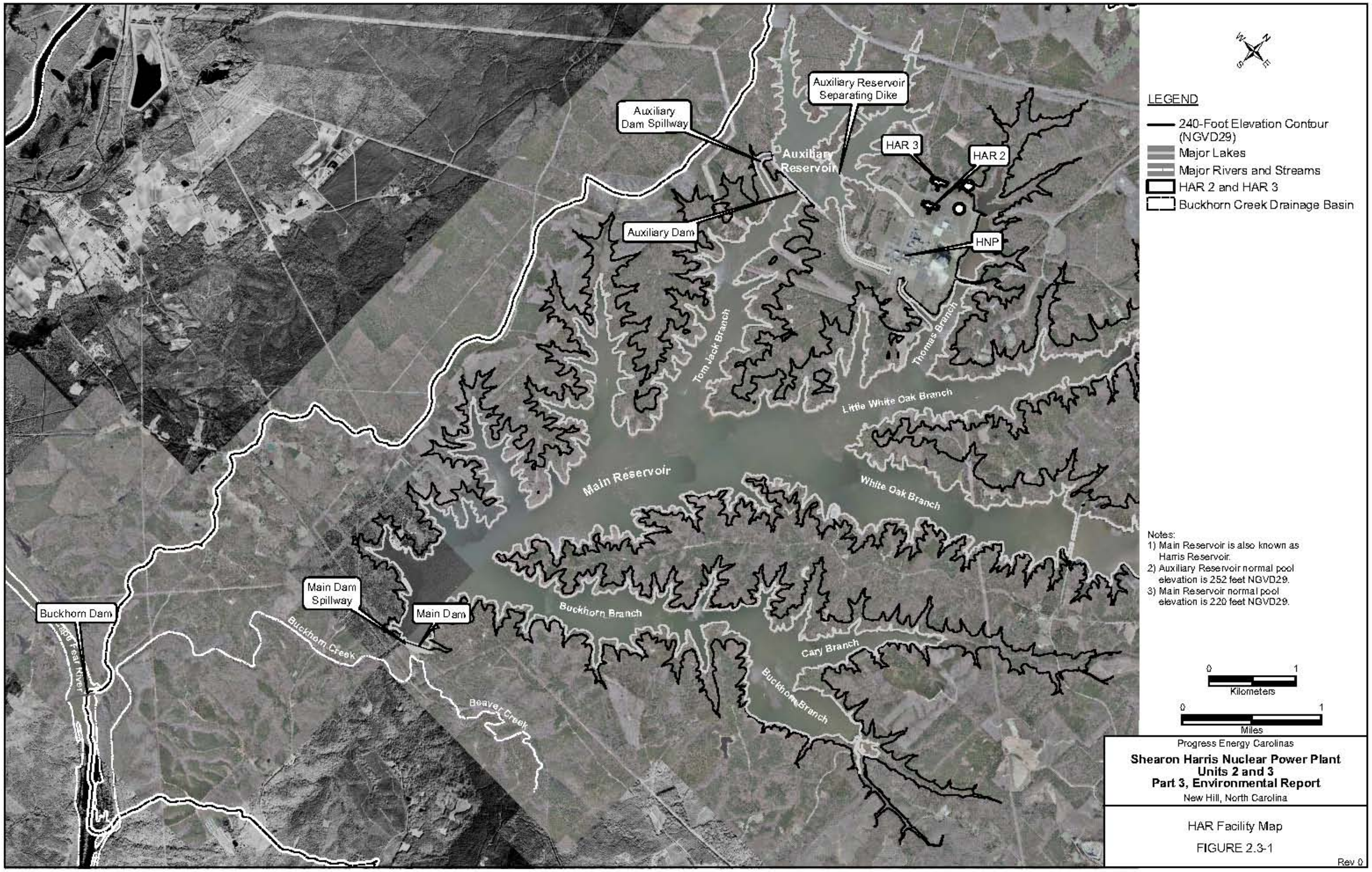
Agenda

- Introductions – Mike Heath
- Harris Plant Information – Dave Corlett
- HNP Water Sources – Dave Corlett
- Feedwater Regulating Valves Open Item – Dave Corlett
- Status of Electrical Manholes – Mike Heath
- Containment Valve Chamber External/Internal Corrosion – Matt Denny

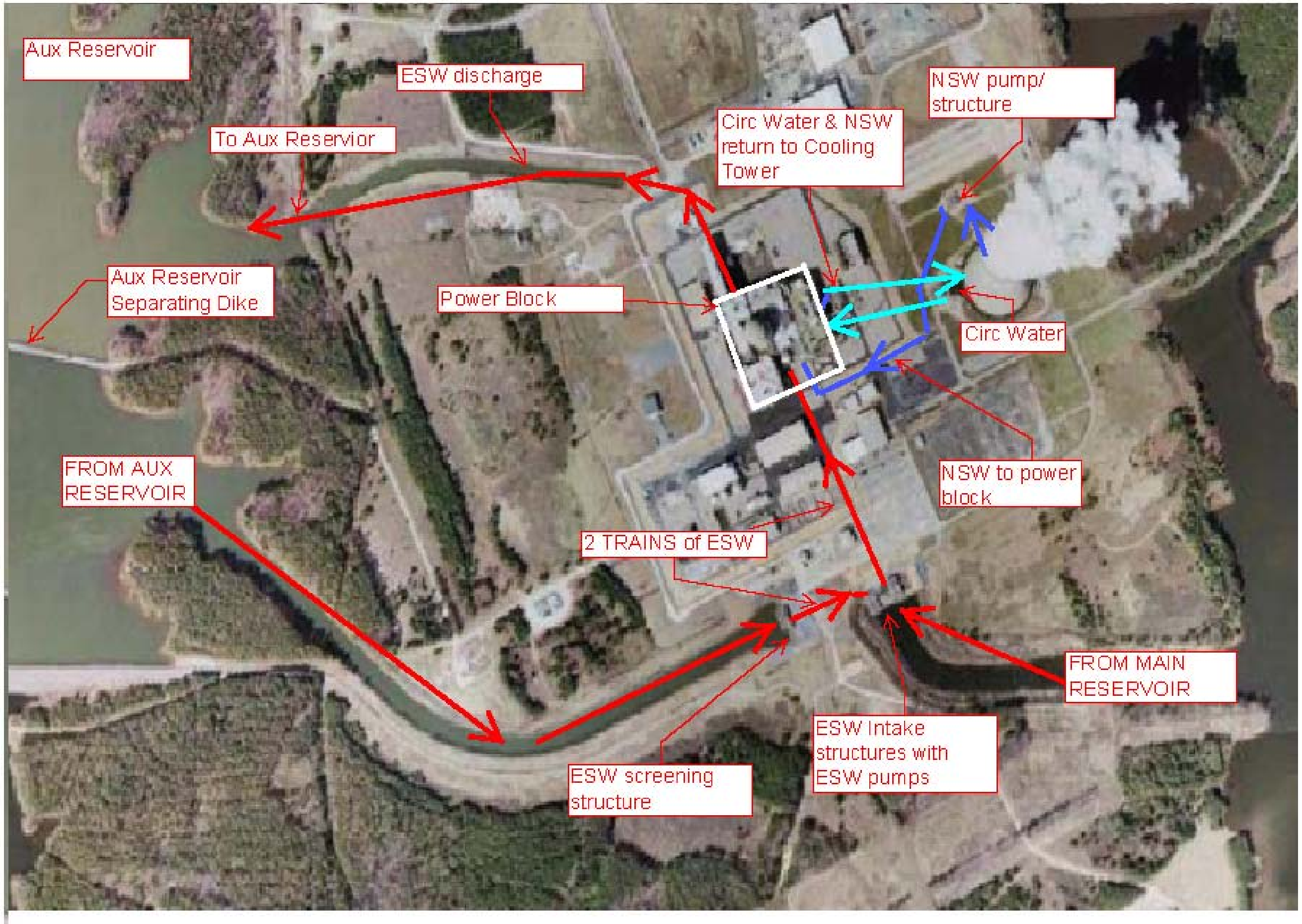
Shearon Harris Plant

- Located South of Raleigh, NC on Harris Lake
- Facility License Issued October 24, 1986
- Westinghouse 3 Loop PWR
  - 2900 MWt; 900 MWe(net)
  - Steel lined, reinforced concrete containment
  - UHS - Cooling via lake with Cooling Tower

HNP Water Sources

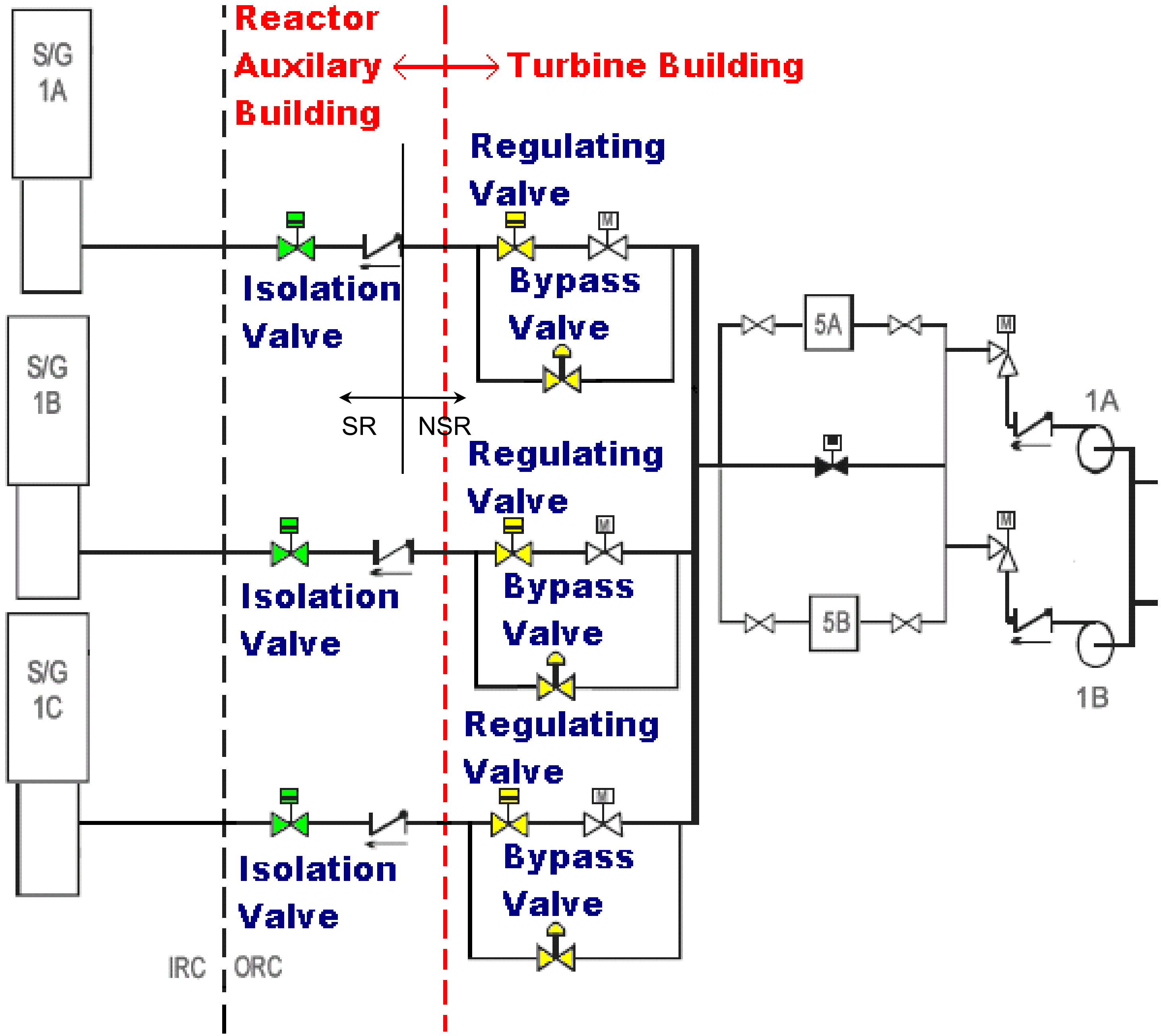


HNP Water Sources & Flow Diagram



Feedwater Regulating Valve Open Item Discussion

- Scoping
  - The Feedwater Regulating Valves Scoped Per 10 CFR 54.4(a)(2) versus (a)(1)



S/G 1A
S/G 1B
S/G 1C
Reactor Auxilary Building
Turbine Building
Regulating Valve
Isolation Valve
Bypass Valve
SR
NSR
Regulating Valve
Isolation Valve
Bypass Valve
Regulating Valve
Isolation Valve
Bypass Valve
5A
5B
1A
1B
IRC
ORC

Feedwater Regulating Valve Open Item Discussion

- Feedwater Regulating Valves and Bypass Valves are nonsafety-related
  - Not Protected From Hazards per CLB
- Safety Function Accomplished by Feedwater Isolation Valves
- Consistent with NUREG-0138, Issue 1, “Treatment of Non-Safety Grade Equipment in Evaluation of Postulated Steam Line Break Accidents.”

Feedwater Regulating Valve Open Item Discussion

- Feedwater Regulating Valves and Bypass Valves Safety Factors
  - Valves close on
    - Main Feedwater Isolation Signal
    - Loss of Instrument Air System
    - Loss of power from Engineered Safety Features Actuation System
    - Loss of DC electric power to solenoids
  - Designed to ASME Section III, Class 3 and Seismic Category 1

Electrical Manholes

- HNP has had two 6.9 kV cable failures:
  - Cable 11525A – MCC 1-4A101 Feeder failed on December 11, 2002 after approximately 15 years in service.
  - Cable 11882A – 1&2X CTMU Pump failed on January 12, 2006 after approximately 19 years in service.

Electrical Manholes

- Base line inspections of all manholes were completed in 2003
- Manholes are pumped down every 90 days
  - SR manhole M505B-SB is pumped down every 45 days
- Water levels trended
  - Some water levels over cables

SR Manhole M523D-SB

Electrical Manholes

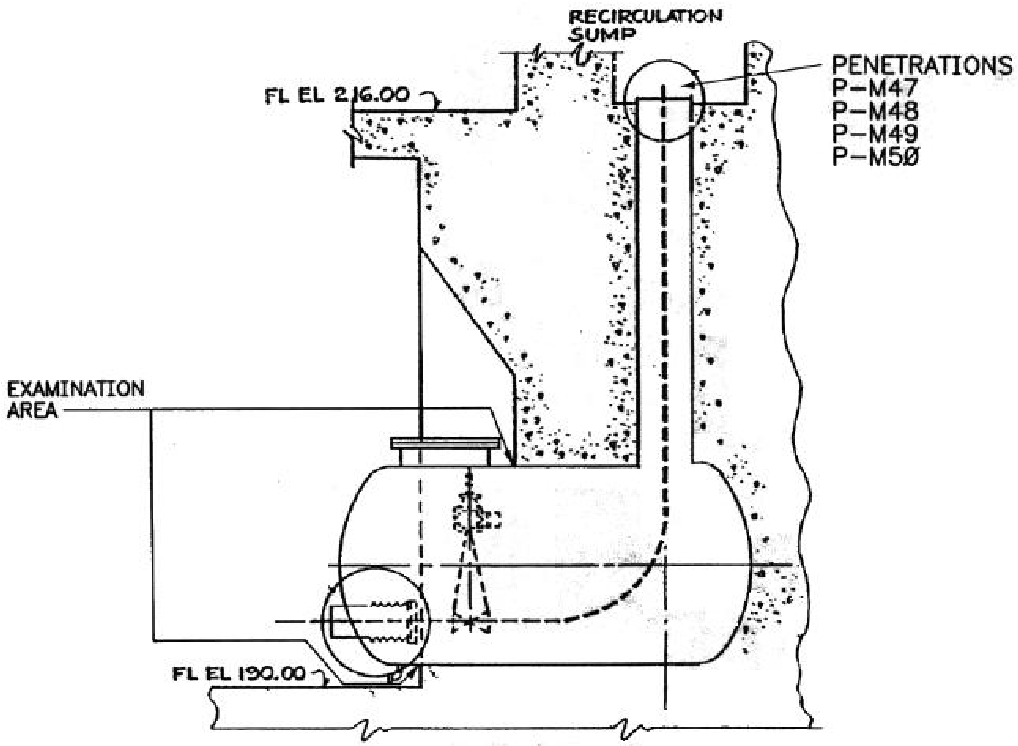
- Medium voltage wetted cables are tested every 6 years
  - Use High Voltage - Very Low Frequency Tan Delta Testing
  - Total of 17 cables
  - Normal Service Water Pump ‘B’, Emergency Service Water Pump ‘A’, and Circulating Water Pump ‘C’ cables tested satisfactorily
  - Maintenance shop feeder cable tested unsatisfactorily

Containment Valve Chamber Corrosion

MAX SAFE NGG GEN 2008

Progress Energy

Containment Valve Chamber Corrosion



ELEVATION VIEW

CT AND RHR VALVE CHAMBERS

Containment Valve Chamber External Corrosion

- Ground Water Intrusion EL 190' & 216' RAB
- Detected as early as the1980's
- 1984 - Pressure grouting
- Later other techniques used
  - e.g. sealant injection (floors & exterior walls)

Containment Valve Chamber External Corrosion

- Water In-leakage Action Plan (1996)
- 15 general areas in several structures
- Corrective actions include:
  - Channeling water in-leakage to floor drains
  - Design changes to core bore drain holes
  - Sump Pumps installed
- Continuing to monitor in-leakage locations

Containment Valve Chamber External Corrosion

- Structures Monitoring Program
  - Engineering personnel inspect SSCs for in-leakage impacts
    - RAB every 6 years
    - FHB and WPB every 7 years
- QC personnel inspect per IWE every ISI period
- HNP Maintenance maintains water control measures
- External surfaces recoated to prevent corrosion

Containment Valve Chamber Internal Corrosion

- RFO10 (2000)
  - Some small blisters on floors of chambers – found acceptable
  - Apparent cause was condensation
- RFO12 (2004)
  - Corrosion under blisters on floor of chambers
  - UT showed wall thickness were above nominal thickness
  - Cause was degraded coatings

Containment Valve Chamber Internal Corrosion

- RFO13 (2006)
  - Coatings were repaired with improved material
- RFO14 (2007)
  - No indications
- QC inspects per IWE every ISI period

Containment Valve Chamber Corrosion

- Conclusion
  - Valve chamber integrity maintained by routine inspections and maintenance

Questions

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Full Committee

Shearon Harris Nuclear Power Plant Unit 1

Safety Evaluation Report

October 2, 2008

Maurice Heath, Project Manager
Office of Nuclear Reactor Regulation

Introduction

- Overview
- Resolution of Open Item 2.2
- Resolution Confirmatory Item 3.4-1
- Resolution Confirmatory Item 4.3

Overview

- License Renewal Application submitted by letter dated November 14, 2006
- Single Unit, Westinghouse 3-Loop - PWR
- 2900 megawatt thermal, 900 megawatt electric
- Operating license NPF-63 expires October 24, 2026
- Location is approximately 20 miles SW of Raleigh, NC

Overview

- Safety Evaluation Report with Open Item was issued March 18, 2008
  - One (1) open item
  - Two (2) confirmatory items
- 346 Audit Questions
- 75 RAIs Issued
- 35 Commitments

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Protecting People and the Environment

Overview

- SER issued August 21, 2008
- Resolution of Open Item (OI) 2.2
- Resolution of Confirmatory Items (CI) 3.4-1 and CI 4.3
- 2 additional commitments added, which were added to resolve the two confirmatory items

Section 2.2: Plant Level Scoping

OI - 2.2

- HNP FSAR credits feedwater regulating and bypass valves for redundant isolation function following a main steam line break. Feedwater isolation is not listed as a function of the feedwater system in the LRA
- The LRA states that the feedwater regulating and bypass valves are non-safety related (NSR), per the CLB and are in scope per 10 CFR 54.4(a)(2)

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Protecting People and the Environment

Section 2.2: Plant Level Scoping

OI - 2.2

- In addressing this OI the staff identified the following:
  - 54.4(a)(1) specifies that safety-related SSCs should be included in scope if they meet 54.4(a)(1)(i),(ii), or (iii)
  - The criteria in 54.4(a)(1)(i-iii) agrees with the definition of safety-related specified in 10 CFR 50.2

Section 2.2: Plant Level Scoping

OI - 2.2

– If the applicants definition of safety-related (SR) differs from 54.4(a), then NEI 95-10 states that applicants should use the criteria of 54.4(a)(1)(i-iii) to determine what SSCs to include in scope.

– If an applicant has CLB documentation indicating the NRC has approved specific SSCs that to be classified as NSR, which would otherwise meet the applicants definition of SR or the 54.4(a)(1) criteria, these SSCs are not required to be within scope in accordance with 54.4(a)(1)

UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Section 2.2: Plant Level Scoping

OI - 2.2

– If SSCs, classified NSR in accordance with CLB, have the potential to affect the functions described in 54.4(a)(1) they should be included within scope in accordance with 54.4(a)(2) – nonsafety-related affecting safety-related.

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UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Section 2.2: Plant Level Scoping

OI - 2.2

- Resolution
  - LRA Amendment 8, dated May 30, 2008, revised Section 2.3.4.6 to add feedwater isolation as an intended function in the Feedwater System
  - HNP has CLB documentation indicating the NRC has approved classifying these valves as NSR
  - LRA Amendment 8, HNP took exception to scoping methodology in NEI 95-10 and used the CLB and scoping definition in 54.4 to determine the valves are in scope per 54.4(a)(2)
  - The staff agrees with the this position as it is consistent with the CLB and scoping definition in 10 CFR 54.4

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Protecting People and the Environment

Section 3: Aging Management Review Results

- Confirmatory Item 3.4-1
  - Applicant credits managing changes in materials and cracking of elastomeric and other plastic components with External Surfaces Monitoring Program
  - GALL AMP XI.M36 recommends visual inspection for carbon steel components but does not address elastomeric and other plastic components
- Resolution
  - Applicant will use the preventative maintenance program, which will periodically replace these components based on site and industry operating experience, equipment history, and vendor recommendations

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Protecting People and the Environment

Section 4: Time-Limited Aging Analysis

- Confirmatory Item 4.3
  - Applicant used WESTEMS™ special purpose computer code in calculating stresses from thermal transients
  - The code is bench marked for pressure, external moments, and thermal transients
  - 60-year fatigue reanalyses were completed for all NUREG/CR 6260 components with two (2) components having 60-year CUFen>1.0
  - CI 4.3 was issued to ensure consistency between reanalysis and original design specification

Section 4: Time-Limited Aging Analysis

CI - 4.3

- Resolution
  - HNP committed to update the design specification to reflect the revised design basis operating transients (Commitment 37)
  - The FSAR supplement was updated to reflect HNP's crediting of the fatigue monitoring program to manage aging for reactor coolant pressure boundary components according to 10 CFR 54.21(c)(1)(iii)

Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

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Protecting People and the Environment

QUESTIONS

Presentation to the ACRS Full Committee

ESBWR Design Certification Review
Chapter 19 & 19A

Presented by
NRO/DNRL/NGE1 and NRO/SPLB

October 2, 2008

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19

Purpose:

- Brief the Committee on the status of the staff's review of the ESBWR DCD application, Chapter 19 and 19A (RTNSS)

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19

Review Team for Chapter 19:

- Lead Technical Reviewer
  - Mark Caruso, Sr. Risk & Reliability Engineer
- Technical Reviewers
  - Edward Fuller, Sr. Risk & Reliability Engineer
  - Marie Pohida, Sr. Risk & Reliability Engineer
  - Glenn Kelly, Sr. Risk & Reliability Engineer
  - John Lai, Risk & Reliability Engineer
  - Jim Xu, Sr. Structural Engineer

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19

Outline of Presentation:

- Objectives of Staff's review
- Summary of Staff's review
- Open Items

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19

Commission's Objectives:

- Use the PRA to identify and address potential design features and plant operational vulnerabilities.
- Use the PRA to reduce or eliminate the significant risk contributors
- Use the PRA to select among alternative features and design options.
- Identify risk-informed safety insights
- Determine how the risk associated with the design compares against the Commission's goals of less than 1x10-4/yr for CDF and less than 1x10-6/yr for LRF and containment performance goals
- Assess the balance between severe accident prevention and mitigation.
- Determine whether the plant design represents a reduction in risk compared to existing operating plants
- Demonstrate compliance with 10 CFR 50.34(f)(1)(i) (i.e., perform a PRA)
- Use PRA in support of programs and processes (e.g., RTNSS, RAP)

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19

Areas of Review with Open Items

- PRA Quality
- Seismic Margins Analysis
- High Winds Analysis
- PRA for Non-power Operational Modes
- Severe Accident Mitigation
- Severe Accident Management

Open Items
PRA Quality

- Applicant's basis for stating PRA quality is adequate for design certification not provided in DCD
  - GEH response to RAI 19.1-155 acceptable
  - Staff will confirm quality, including completeness, of PRA Rev. 3 in site audit
- Concerns with success criteria for passive systems resolved

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19

Open Items
Seismic Margins Analysis

- GEH used a spectrum shape different from the Certified Seismic Design Response Spectra (CSDRS) for HCLPF* estimates in Seismic Margins Analysis (SMA)

- Majority of SSCs treated in SMA assume a HCLPF equal to the limit of 1.67xSSE; however, the SSE has not been defined as CSDRS in the DCD.

- Staff requested that GEH include an ITACC for verification of the assumed seismic capacity for differential building displacements of 1.67***CSDRS**. Staff is awaiting response to RAI from GEH.

*High Confidence of Low Probability of Failure defined as: Earthquake level at which, with high confidence (95 percent), it is unlikely (probability less than 5x10-2) that failure of the SSC will occur.

ACRS Subcommittee Presentation
ESBWR Design Certification Review
Chapter 19

Open Items
High Winds Analysis

- Assumed conditional probability that Category 4 or 5 hurricanes will damage structures not justified
  - Awaiting GEH response to RAI
- Not clear whether credit was taken for equipment in Seismic Category II structures hit by tornado missiles
  - Awaiting GEH Response to RAI

ACRS Subcommittee Presentation
ESBWR Design Certification Review
Chapter 19

Open Items
PRA for Other Operational Modes

- Staff requests GE to add DPS operability to TS for Modes 5 and 6 or assess risk of RWCU/SDC breaks outside of containment (RAI 19.1.-178)
- Staff requests GE to document sizes of piping penetrations and associated alarm/position indication upstream of RWCU/SDC isolation valves or assess operator induced leaks (RAI 19.1.0-4 Supplement 2)
- Staff questions ability of Isolation Condenser to function effectively for some operational conditions in Mode 5 (RAI 19.1-144 Supplement 2)

ACRS Subcommittee Presentation
ESBWR Design Certification Review
Chapter 19

Open Items
PRA for Other Operational Modes

- GEH must determine range of conditions (temperature and level) for which the RWCU/SDC can adequately remove decay heat in Modes 4, 5, and 6 (RAI 5.4-59 Supplement 1)
  - Staff concerned about inadequate vessel circulation between inside and outside shroud
  - Staff concerned that RWCU/SDC injection may bypass the core due to inadequate mixing in downcomer.

ACRS Subcommittee Presentation
ESBWR Design Certification Review
Chapter 19

Open Items
Severe Accident Mitigation

- BiMAC performance test report
  - Response to RAIs19.2-23 S02 and 19.2-25 S02 included a topical report documenting the results of the BiMAC tests.
  - Topical report NEDE-33392 has been reviewed and 27 RAIs prepared.
- Sent a new RAI to GEH asking for transient analyses of BiMAC behavior during severe accidents for both high and low RCS pressure scenarios.

ACRS Subcommittee Presentation
ESBWR Design Certification Review
Chapter 19

Open Items

Accident Management

- Description of the process for developing Severe Accident Guidelines
  - The staff requested additional information on the process that will be used by GEH to develop the Severe Accident Guidelines (SAGs) in RAI 19.2.4-1 and its supplements.
  - A new supplemental RAI has been issued, asking for the technical basis for ESBWR severe accident management.

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Review Team for Chapter 19A (SER Chap. 22):

- Lead Technical Reviewer
  - Mark Caruso, Sr. Risk & Reliability Engineer

- Technical Reviewers
  - Eugene Eagle, Instrumentation and Controls Engineer
  - Craig Harbuck, Sr. Operations Engineer
  - Thomas Scarbrough, Sr. Mechanical Engineer
  - Mohamed Shams, Structural Engineer
  - David Shum, Sr. Reactor Systems Engineer
  - George Thomas, Sr. Reactor Systems Engineer
  - Hanry Wagage, Sr. Reactor Engineer

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Outline of Presentation:

- Objectives of Staff's review
- Summary of Staff's review
- Open Items

Regulatory Treatment of Non-Safety Systems (RTNSS)

Objectives of Staff's Review

- Confirm all non-safety SSCs requiring treatment are identified
- Confirm reliability and availability (R/A) missions for active systems are consistent with risk assessment
- Confirm level of treatment is based on ability to meet R/A missions (i.e., TS, Availability Controls Manual, Maintenance Rule program)

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Areas of Review with Open Items

- Augmented Design Standards for Post-72 hour equipment
- Regulatory Treatment of Active Systems
- Availability Controls

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Open Items

Augmented Design Standards for Post-72 Hours Equipment

- Staff is satisfied that RTNSS systems can be adequately protected from flood-related effects associated with both natural phenomena and system and component failures (design meets standards).
- Staff wants GEH to propose an ITAAC to ensure as-built plant implements the design properly.

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Open Items

Regulatory Treatment

- Risk significance criteria for determining treatment level of active systems applied inconsistently
  - Awaiting GEH response to RAI 22.5-26

- Treatment of electric fire pump dedicated to low pressure injection needs to be clarified.
  - Awaiting GEH response to RAI 22.5-27

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Open Items

Availability Controls (AC)

- ACs did not state the associated instrumentation functions and the number of required divisions in the AC LCOs for some functions
  - Awaiting GEH response to RAI 22.5-22

- AC bases do not explicitly state the minimum level of system degradation that corresponds to a function being unavailable, or the number of divisions used to determine the test interval for each required division (or component) for AC surveillance requirements
  - Awaiting GEH response to RAI 22.5-22

- No AC Surveillance Requirements provided for FAPCS pumps
  - Awaiting GEH response to RAI 22.5-23

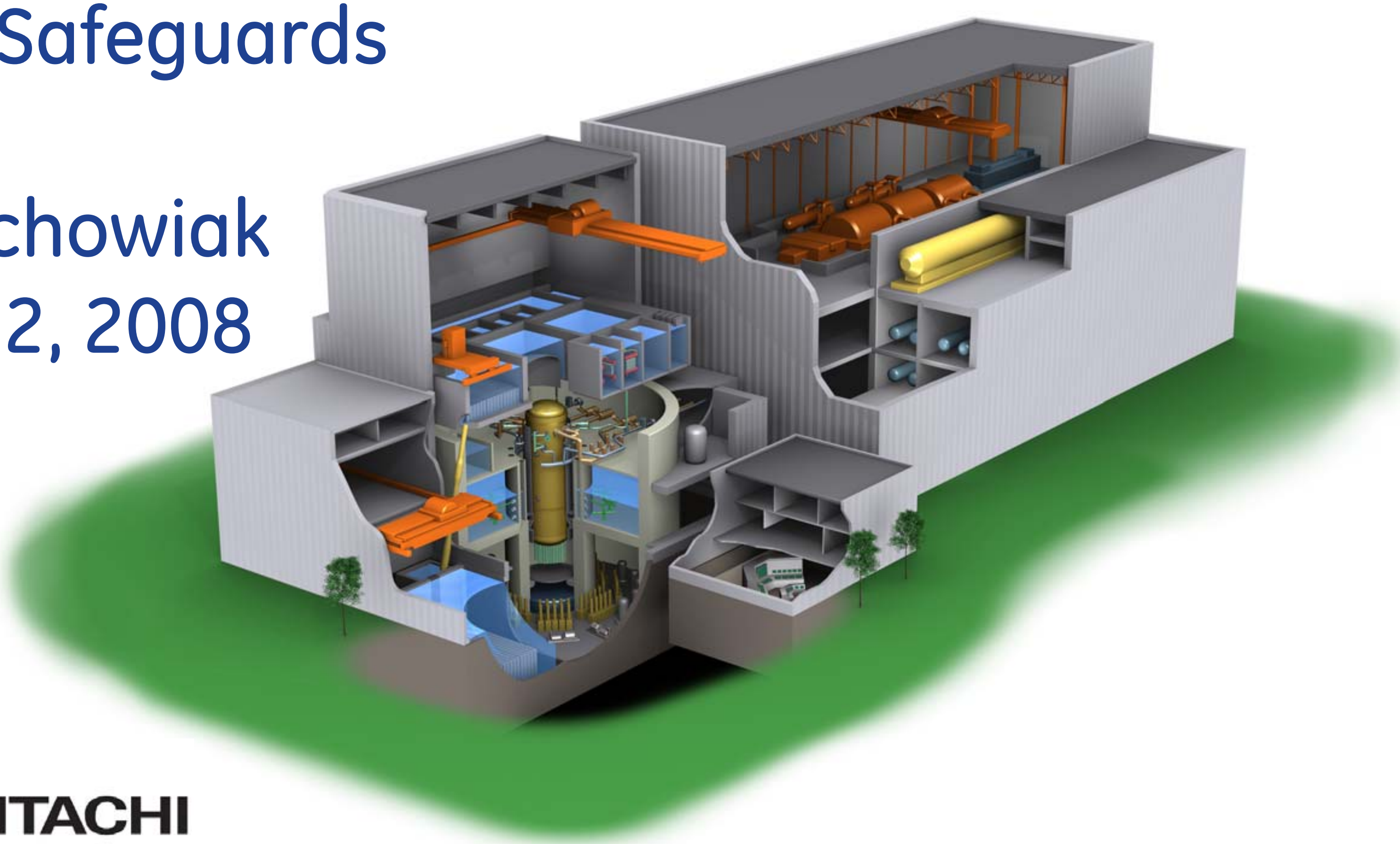
- AC LCOs for FAPCS and EDGs inconsistent with PRA assumptions
  - Awaiting GEH response to RAI 22.5-24

ACRS Full Committee Presentation
ESBWR Design Certification Review
Chapter 19A (SER Chap. 22)

Discussion / Questions

ESBWR PRA and Severe Accidents

Presented to the
Advisory Committee on
Reactor Safeguards



Rick Wachowiak
October 2, 2008

HITACHI

Design Certification PRA Objectives

10 CFR 50.34(f)(1)(i) requires a Design Certification PRA to address known design issues with respect to core and containment heat removal systems

Identify vulnerabilities

Demonstrate that the plant meets the Commission's safety goals

Reduce/eliminate risk contributors in existing plants

Select among SAM design features

Identify risk-informed safety insights

Show a balance of severe accident prevention and mitigation

Show a reduction in risk in comparison to existing plants

Support design programs such as RTNSS and D-RAP

HITACHI

Interaction With NRC Staff On ESBWR PRA

Nearly 450 RAIs (almost 8% of total for certification)

- 386 resolved

Three on-site audits

Several meetings and teleconferences

Audit of revision 4 PRA expected in the first week of December

Focused on the design certification PRA objectives

Design Certification Not the Last ESBWR PRA

Revised PRA required by 10 CFR 50.71(h)(1)

- Level 1 and Level 2
- Prior to initial fuel load
- Must meet all endorsed standards

No intention that the DC PRA must satisfy this requirement

Maintained by the licensee for NRC inspection

Need for submittal to NRC based on each specific risk informed application requirements

Ongoing PRA Upgrade Requirements

10 CFR 50.71(h)(2) requires PRA maintenance or upgrade as new standards are endorsed

- 4 year periodicity
- PRA maintenance and PRA upgrade consistent with definition in ASME “Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications”

HITACHI

ESBWR Design Certification PRA

Meets the scope and quality for certification

Meets the scope and quality for COL given no significant departures from the certified design

Provides a starting point for operating plant PRA

HITACHI

Organization of ESBWR PRA Reports

DCD Chapter 19 describes the PRA and lists key insights

NEDO 33201 ESBWR Certification Probabilistic Risk Assessment, R3 May 2008

NEDO 33289 ESBWR Reliability Assurance Program, R2 September 2008

NEDO 33306 ESBWR Severe Accident Mitigation Design Alternatives, R1 August 2007

NEDO/NEDE 33386 ESBWR Plant Flood Zone Definition Drawings and Other PRA Supporting Information, R0 September 2007

NEDO/NEDE 33392(P) The MAC Experiments: Fine Tuning of the BiMAC Design, R0 March 2008

NEDO 33411 Risk Significance of Structures, Systems, and Components for the Design Phase of the ESBWR, R0 March 2008

Key Features of ESBWR Design Risk Management

Passive safety systems

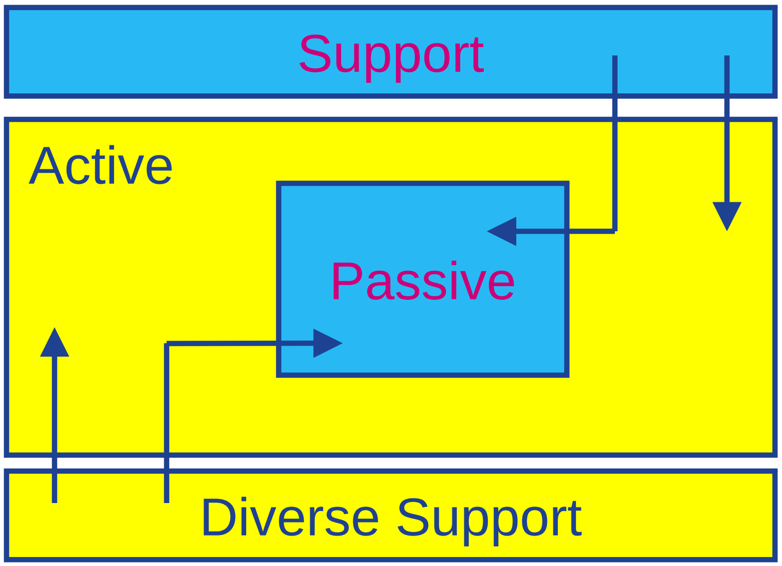
Active asset protection systems

Support system diversity

Minimize reliance on human actions

Use applicable historical data

Target configuration for core damage prevention functions



HITACHI

Features of ESBWR PRA

- Detailed Fault Tree / Event Tree Models
- Level 1, 2, and 3
- Internal & External Events
- All Modes
- Seismic Margins
- Generic Data
- Historical Initiating Event Frequencies
- Parametric Uncertainty
- Systematic Search for Key Modeling Uncertainties
- Internal review for compliance with ASME-RA-Sb-2005

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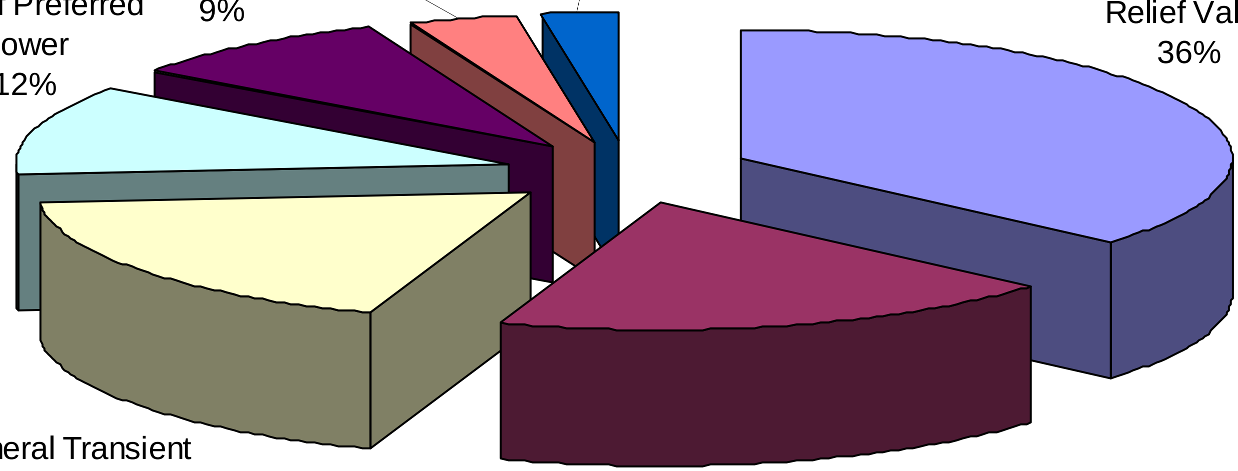
ESBWR Core Damage Risk Profile



$$CDF_{pe} = 1.2x10^{-8} /yr$$

At power internal events

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Overall Results

	Internal Events	Fire	Flood	High Winds
At-Power CDF	1.2×10^{-8}	8.1×10^{-9}	1.6×10^{-9}	1.3×10^{-9}
Shutdown CDF	9.4×10^{-9}	2.7×10^{-8}	5.2×10^{-9}	1.2×10^{-9}
At-Power LRF	1.0×10^{-9}	5×10^{-10}	2×10^{-10}	3×10^{-11}
Shutdown LRF	9.4×10^{-9}	2.7×10^{-8}	5.2×10^{-9}	1.2×10^{-9}

Point Estimate Values
Units are per calendar year

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Scope of Severe Accident Analyses

Discussion of severe accident prevention

- Examples: ATWS, SBO, Fire Protection & ISLOCA

Discussion of severe accident mitigation

- Examples: Hydrogen control, debris coolability, high-pressure melt eject, containment performance, containment vent, equipment survivability

Severe accident mitigation design alternatives

Contained in DCD Ch 19, NEDO-33201 Ch 21, and NEDO-33306

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PRA Was a Major Influence on Design

Examples

- Design of digital / mechanical interface to eliminate spurious actuations from fire
- Selection of diverse components
- Addition of redundancy to RWCU isolation features
- Addition of BiMAC to preclude containment failure
- Main control room design
- Addition of severe accident water injection pump
- More enhancements identified to resolve during procedure development

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NRC Staff Review Helped Enhance PRA

Examples

- Extend Level 3 to external events
- Enhanced documentation of assumptions
- Upgrade from FIVE to Fire PRA
- Systematic evaluation of the PRA with respect to endorsed standards

Limited Open Items Remain

PRA quality assessment

- GEH responded and it is under staff review
- Audit of ESBWR PRA scheduled for December

Seismic margins analysis

- Selection of response spectrum
- GEH response is in development

High winds analysis

- Assumptions for building capabilities in extreme wind events
- GEH response is in development

Shutdown event details

- GEH responded to 2 issues / in development for 2 issues

Severe accident resolution

- Questions from BiMAC test report
- GEH responses are in development

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NRC RTNSS Criteria

A SSC functions relied upon to meet beyond design basis deterministic NRC performance requirements such as 10CFR50.62 for anticipated transient without scram (ATWS) mitigation and 10CFR50.63 for station blackout

B SSC functions relied upon to resolve long-term safety (beyond 72 hours) and to address seismic events

C SSC functions relied upon under power-operating and shutdown conditions to meet the Commission's safety goal guidelines of a core damage frequency of less than 1.0E-4 each reactor year and large release frequency of less than 1.0E-6 each reactor year

D SSC functions needed to meet the containment performance goal (SECY-93-087, Issue I.J), including containment bypass (SECY-93-087, Issue II.G), during severe accidents

E SSC functions relied upon to prevent significant adverse systems interactions

RTNSS Design Treatment

Redundant active components

Fire and flood protected

Hurricane category 5 missile protection

Designed for accident environment

Quality suppliers (not Appendix B)

Seismic category II for post-72 hr functions

Technical Specifications for SSCs Needed to Meet CDF and LRF Goals

Availability Controls Manual for Frontline Systems

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RTNSS Open Items

Availability Controls

- ACs did not state the associated instrumentation functions and the number of required divisions in the AC LCOs for some functions
- AC bases do not explicitly state the minimum level of system degradation that corresponds to a function being unavailable, or the number of divisions used to determine the test interval for each required division (or component) for AC surveillance requirements
- No AC Surveillance Requirements provided for FAPCS pumps
- AC LCOs for FAPCS and EDGs inconsistent with PRA assumptions

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RTNSS Open Items

Design standards for post-72 hour functions

- Resolved

Augmented design standards for flood protection

- Existing RAIs resolved

RTNSS status of some active systems

- Responses in development

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Conclusions

ESBWR PRA and Severe Accident chapters meet the requirements for certification

Limited open items to be resolved

NRC review confirms that the required objectives will be satisfied in the DCD

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Historical Perspectives and Insights on Reactor Accident Consequences Analyses

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Advisory Committee on Reactor Safeguards (ACRS)

Presented at

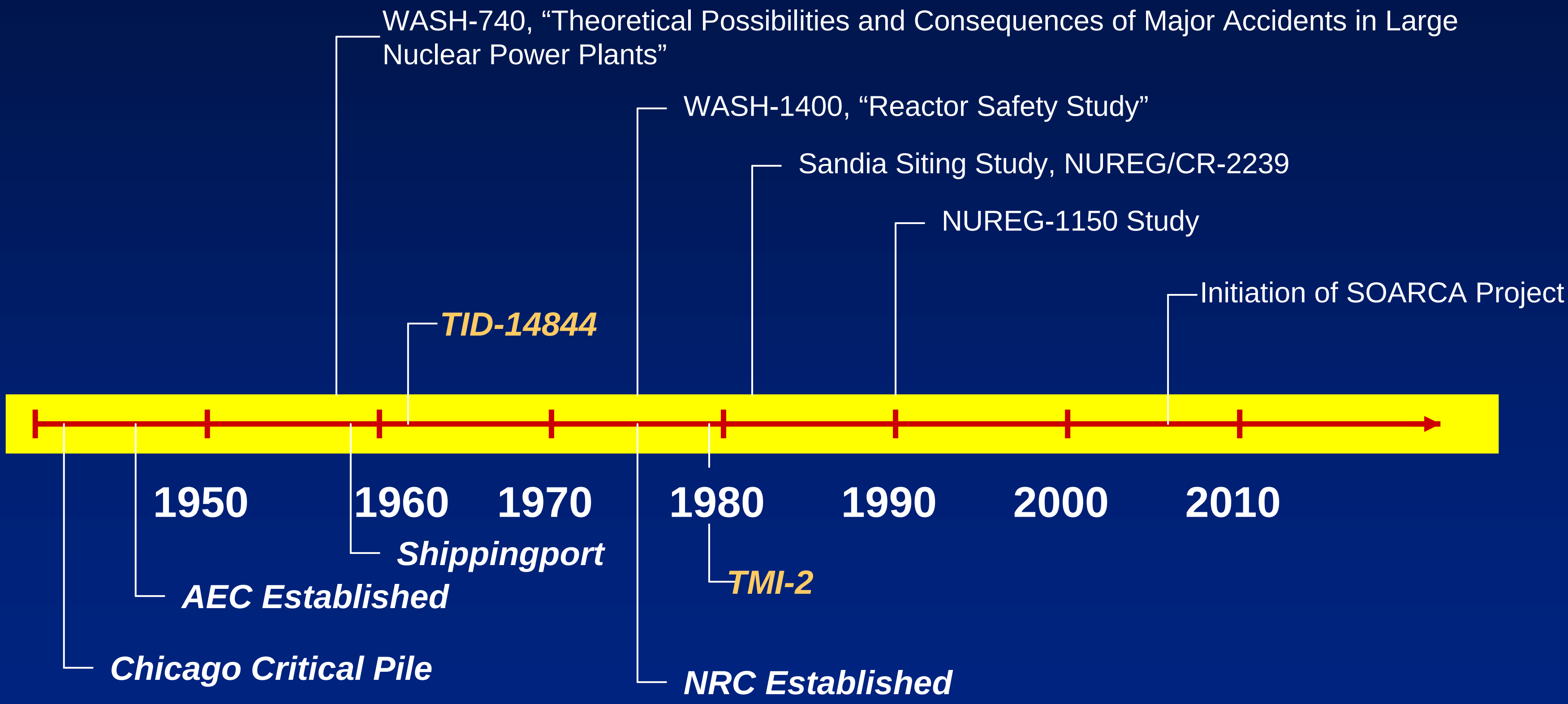
556th Meeting of ACRS

October 2, 2008

Objectives

- To provide historical perspectives and insights on previous state-of-the-art analyses of the consequences of severe reactor accidents
- To discuss the feasibility of using a simplified, yet systematic and defensible, approach to benchmark many aspects of SOARCA

Timeline of Major Studies of Reactor Accident Consequences



WASH-740

- The first estimates of consequences of severe accidents were published in the 1957 U.S. Atomic Energy Commission report (WASH-740), “Theoretical Possibilities and Consequences of Major Accidents in Large Nuclear Power Plants”
- An attempt to provide upper bounds of the potential public hazards resulting from certain severe hypothetical accidents
- Conservative values were used for many factors influencing the magnitude of the estimated accident consequences
- At the time, the technology and the state-of-knowledge of severe accidents had not progressed to the point where it was possible to use quantitative techniques to estimate the probabilities of such accidents. However, there was a general agreement that the probability of occurrence of severe accidents in nuclear power reactors was exceedingly low.

Reactor Safety Study (WASH-1400)

- The first systematic attempt to provide realistic estimates of public risk from potential accidents in commercial nuclear power plants
- Included analytical methods for determining both the probabilities and consequences of various accident scenarios
- Two specific reactor designs were analyzed in WASH-1400, Surry and Peach Bottom
- Calculations were performed for a number of accident sequences and the results for these calculations were used to define a series of release categories (nine for PWR and five for BWR) into which all of the identified accident sequences could be placed.

Post TMI-2 Review of Source Term Technical Basis

- Following the publication of WASH-1400 and the accident at TMI-2, work initiated to review the predictive methods for calculating fission product release and transport
- Review resulted in several conclusions that represented significant departure from WASH-1400 assumptions including the suggestion that cesium iodide (CsI) will be the expected predominant iodine chemical form under most postulated LWR accident conditions
- These studies formed the basis for development of a generic set of radiological releases, characterized as Siting Source Terms (denoted SST1-5), used in Sandia Siting Study (NUREG/CR-2239)

Brief Descriptions of the Characteristics of the Accident Groups

(NUREG-0771, p. 8)

Group 5 - Limited core damage. No failures of engineered safety features beyond those postulated by the various design basis accidents are assumed. The most severe accident in this group includes substantial core melt, but containment functions as designed (siting DBA equivalent).

Group 4 - Limited to modest core damage. Containment systems operate but in somewhat degraded mode (TMI-2 equivalent)

Group 3 - Severe core damage. Containment fails by basemat melt-through. All other release mitigation systems have functioned as designed (analogous to Reactor Safety Study Pressurized Water Reactor, PWR, Categories 6 and 7)

Group 2 - Severe core damage. Containment fails to isolate. Fission product release mitigating systems (e.g., sprays, suppression pool, fan coolers) operate to reduce release (analagous to Reactor Safety Study PWR Categories 4 and 5)

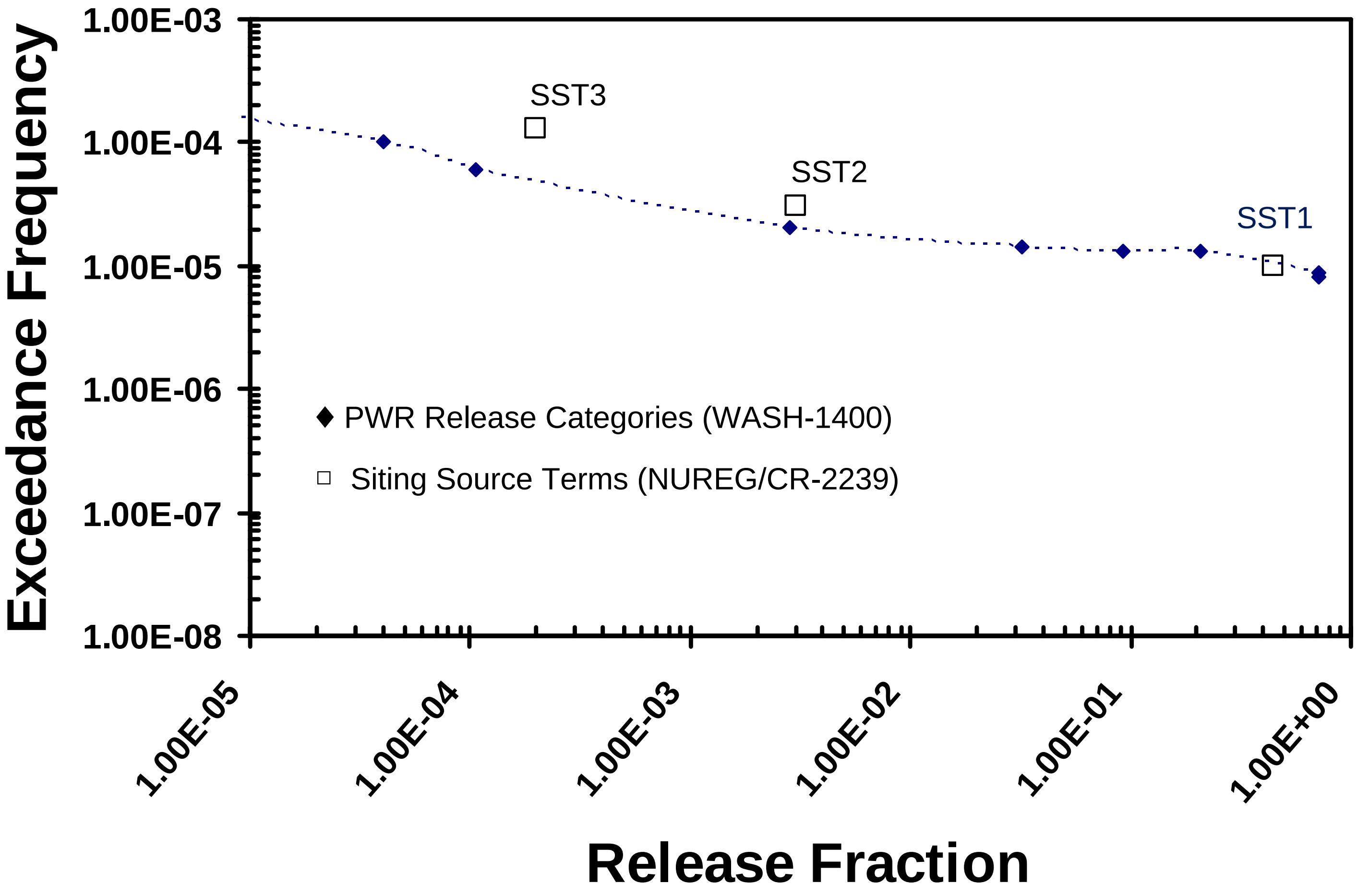
Group 1 - Severe core damage. Essentially involves loss of all installed safety features. Severe direct breach of containment (analogous to Reactor Safety Study PWR Categories 1 and 3)

Sandia Siting Study (NURG/CR-2239)

- Used Siting Source Terms (SSTs) at 91 existing or proposed reactor sites to perform accident consequence analyses
- Detailed PRAs were not performed for all reactors. Based on available PRAs at the time, NRC suggested the following representative probabilities for the SSTs
  - SST1 1×10^{-5}
  - SST2 2×10^{-5}
  - SST3 1×10^{-4}

Frequecy of Release for Iodine

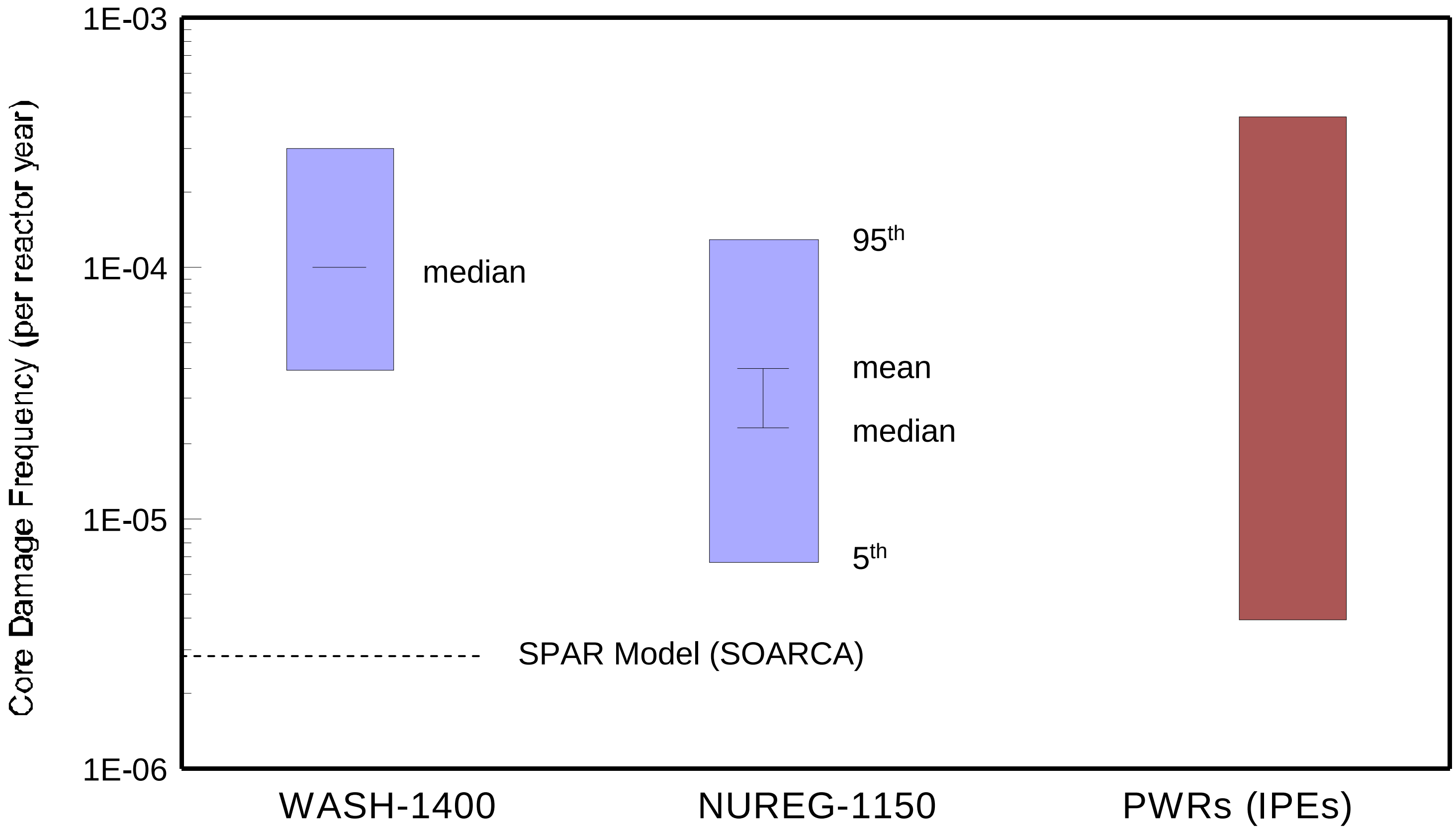
(Comparison of WASH-1400 PWR Release Categories and SSTs)



NUREG-1150 Study

- The NUREG-1150 study was a major effort to put into a risk perspective the insights into system behavior and phenomenological aspects of severe accidents
- An important characteristic of this study was the inclusion of the uncertainties in the calculations of core damage frequency and risk that exist because of incomplete understanding of reactor systems and severe accident phenomena
- The elicitation of expert judgment was used to develop probability distributions for many accident progression, containment loading, structural response, and source term issues
- Five specific commercial nuclear power plants were analyzed :
  - Surry, a 3-loop Westinghouse PWR with a subatmospheric containment
  - Zion, a 4-Loop Westinghouse PWR with large dry containment
  - Sequoyah, a 4-loop Westinghouse PWR with ice-condenser containment
  - Peach Bottom, a BWR-4 reactor with a Mark I containment
  - Grand Gulf, a BWR-6 reactor with a Mark III containment

Internal Core Damage Frequency for Surry



Conditional Probability of Accident Progression Bins at Surry
(NUREG-1150, p. 3-12)

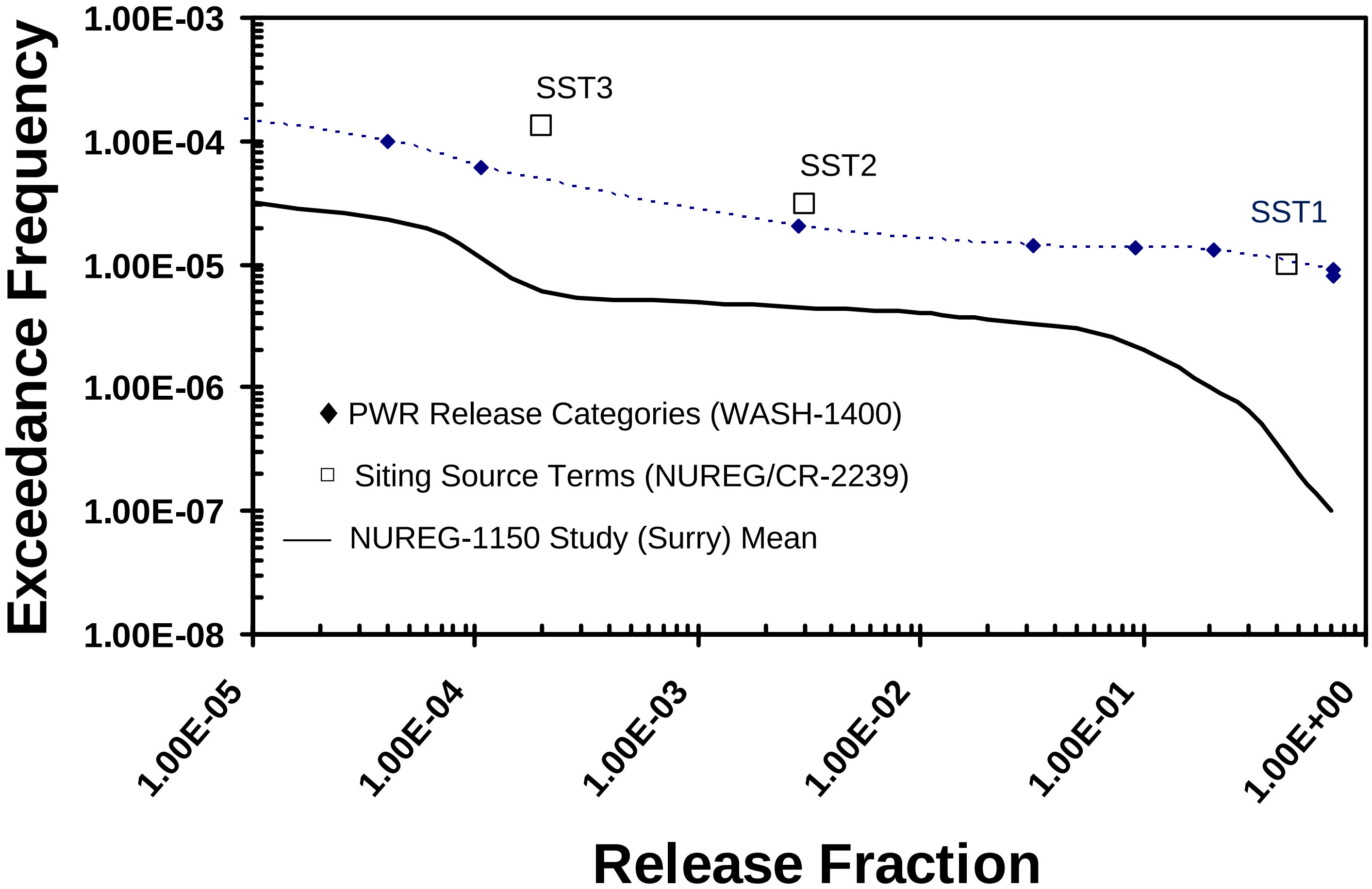
SUMMARY PDS GROUP (Mean Core Damage Frequency)

SUMMARY ACCIDENT PROGRESSION BIN GROUP	Internal Initiators: LOSP (2.8E-05)	Internal Initiators: ATWS (1.4E-06)	Internal Initiators: Transients (1.8E-06)	Internal Initiators: LOCAs (6.1E-06)	Internal Initiators: Bypass (3.4E-06)	Internal Initiators: All (4.1E-05)	Fire (1.1E-05)	Seismic LLNL (1.9E-04)
VB, alpha, early CF	0.003	0.003		0.005		0.003	0.005	0.006
VB > 200 psi, early CF	0.005		0.001	0.001		0.004	0.013	0.008
VB, < 200 psi, early CF								0.082
VB, BMT or late CL	0.079	0.046	0.013	0.055		0.059	0.292	0.280
Bypass	0.003	0.078	0.007		1.000	0.122		0.001
VB, No CF	0.310	0.523	0.217	0.586		0.346	0.690	0.435
No VB	0.599	0.350	0.762	0.352		0.466		0.189

Key: BMT = Basemat Melt-Through
CF = Containment Failure
CL = Containment Leak
VB = Vessel Breach

Frequecy of Release for Iodine Group

(Comparison of WASH-1400 PWR Release Categories, SSTs, and NUREG-1150)



Reassessment of Selected Factors Affecting Siting of Nuclear Power Plants (NUREG/CR-6295)

- A series of probabilistic consequence assessment calculations were performed in support of an effort to re-assess reactor siting
- Insights from NUREG-1150 and the LaSalle independent risk assessment studies were used to develop representative source terms
  - A small set of source terms (4 to 7 for each plant) based on dominant plant damage states, accident progression groups and the associated release characteristics were developed for each reactor design to represent the full spectrum of severe accidents
- Examined consequences in a risk based format consistent with the quantitative health objectives (QHOs) of the NRC's Safety Goal Policy

Characteristics of Surry Release Categories, Internal Events

(NUREG/CR-6295, pp 3-19)

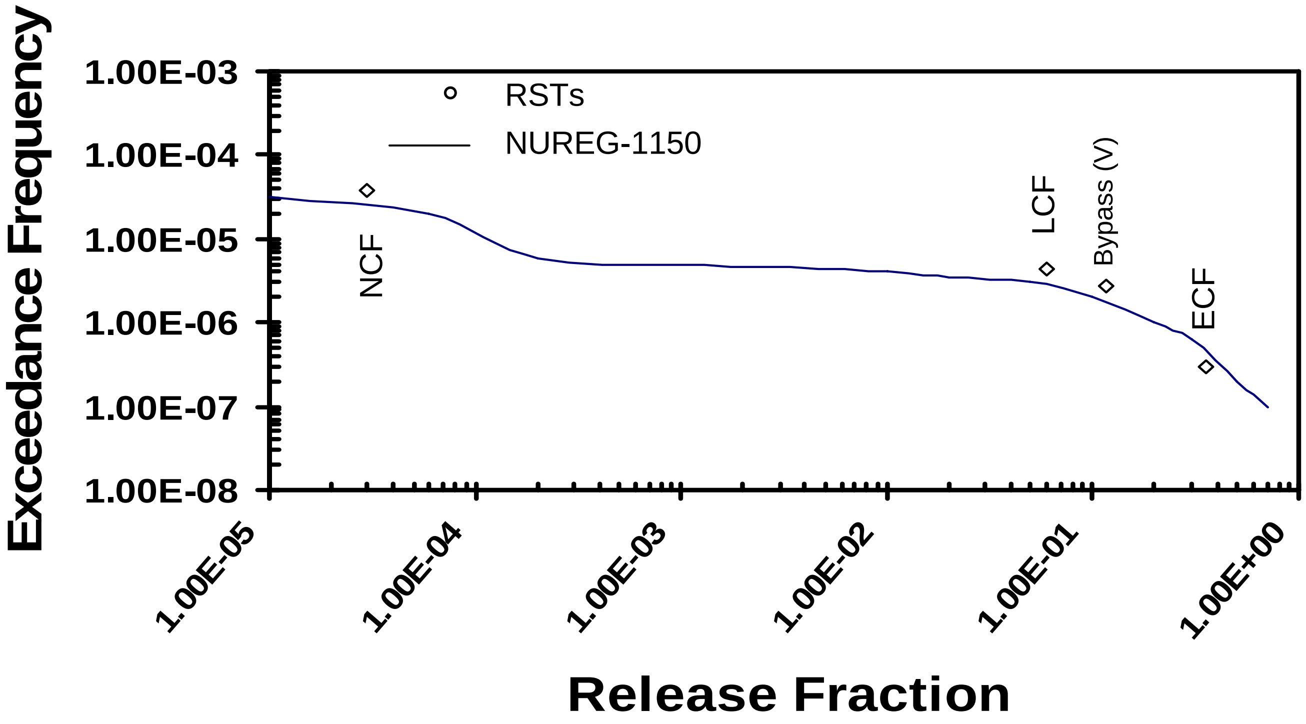
Release Category	Plant Damage State	Accident Progression Characteristics						
		Containment Failure Time	Containment Failure Mode	CCI	Amt CCI	RCS Pres.	VB Mode	Sprays
RSUR1	LOSP	CF at VB	Rupture	Prm Dry	Medium	Low	Alpha	No
RSUR2	LOSP	Late CF	Leak	Prm Dry	Large	Low	Pour	No
RSUR3	LOSP	No CF	No CF	Prm Dry	Large	Low	Pour	L+VL
RSUR4	Bypass (V)	No CF	Bypass	Prm Dry	Large	Low	Pour	No

Radionuclide Release Characteristics into Environment for Surry, Internal Events

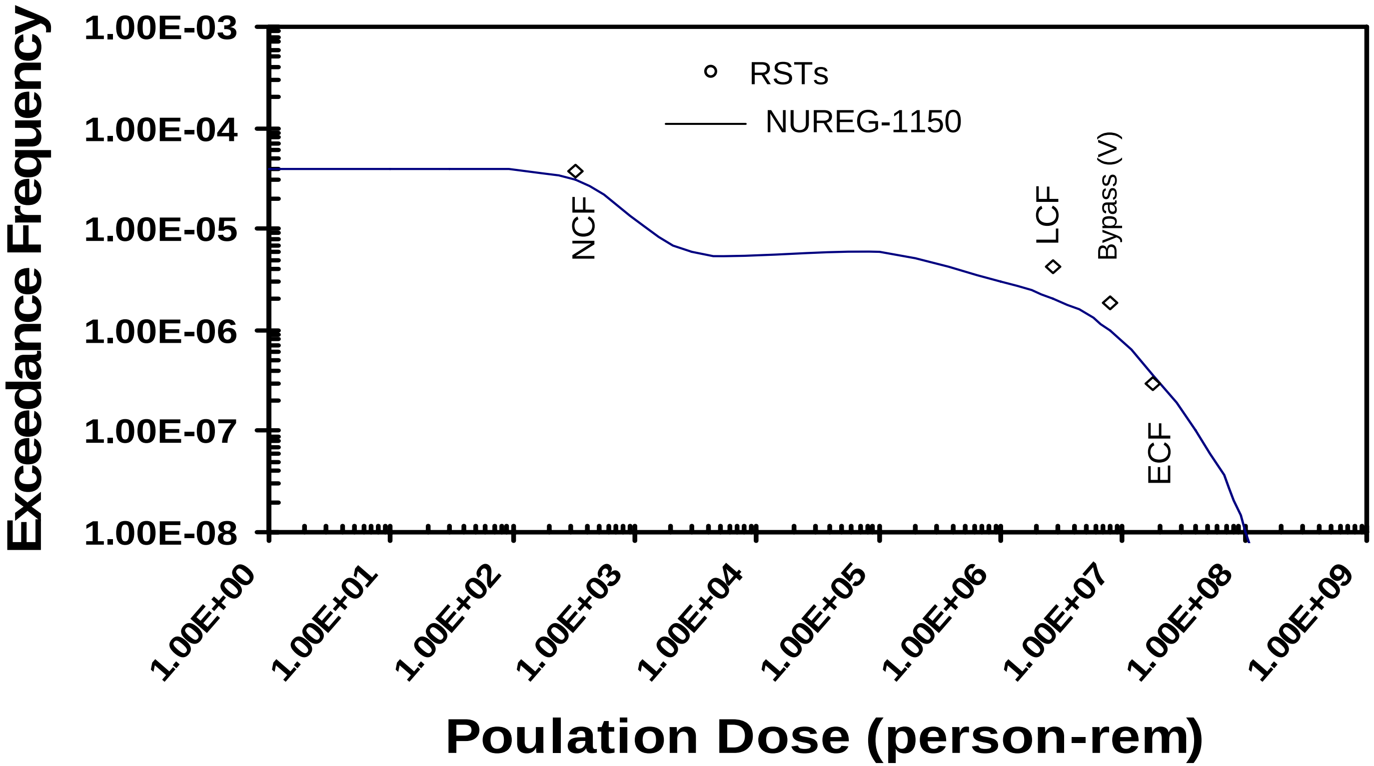
(NUREG/CR-6295, pp3-19)

Release Category	Frequency	Elevation (m)	Energy (W)	Time of Core Uncovery	Time of Release (hrs)	Release Duration	Fractional Releases								
							Ng	I	Cs	Te	Sr	Ba	Ru	La	Ce
RSUR1	2.9E-7	10	2.8E+7	5.0 hrs	6.0	200 sec	1.0E+0	2.5E-1	1.8E-1	8.0E-2	2.0E-2	2.0E-2	5.0E-3	1.0E-3	5.0E-3
		10	1.6E+6		6.06	2 hrs	0.0E+0	1.0E-1	1.3E-1	1.0E-1	4.0E-2	4.0E-2	1.0E-3	5.0E-3	5.0E-3
RSUR2	2.4E-6	10	5.2E+5	5.0 hrs	12.0	3 hrs	1.0E+0	6.0E-2	3.0E-2	9.0E-2	3.0E-3	3.0E-3	1.0E-3	4.0E-4	4.0E-4
RSUR3	3.3E-5	0	0.0E+0	5.0 hrs	6.0	10 hrs	2.5E-3	1.5E-5	1.2E-8	7.5E-9	2.5E-9	2.5E-10	2.0E-10	3.0E-10	4.0E-10
		0	0.0E+0		16.0	10 hrs	2.5E-3	1.5E-5	1.2E-8	7.5E-9	2.5E-9	2.5E-10	2.0E-10	3.0E-10	4.0E-10
RSUR4	1.6E-6	0	1.9E+6	20 min	1.0	30 min	1.0E+0	7.5E-2	6.0E-2	2.0E-2	5.0E-3	5.0E-3	1.0E-3	3.0E-4	1.0E-3
		0	1.7E+5		1.5	2 hrs	0.0E+0	4.0E-2	6.0E-2	6.0E-2	2.0E-2	2.0E-2	6.0E-4	3.0E-3	3.0E-3

Frequency of Release for Iodine Based on Representative Source Terms (RSTs) for Surry Internal Events



Frequency of Population Dose to Entire Region at Surry



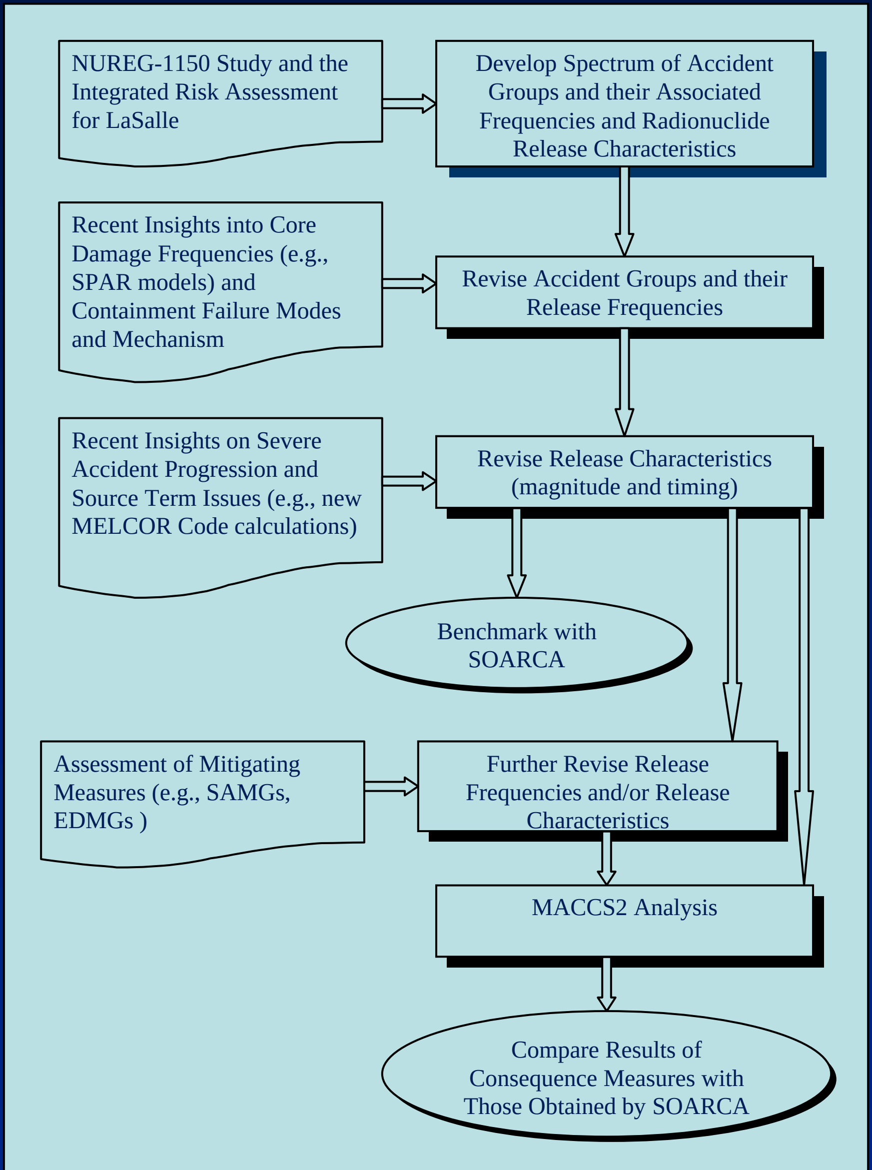
Recent Advances in Understanding of Severe Accident Phenomenology and Containment Failure Mechanisms

- Since the completion of NUREG-1150 Study, more analytical and experimental studies have been performed to address many severe accident issues including:
  - Direct Containment Heating (DCH) Issue
  - "Mark I Liner Attack" Issue
  - In-vessel steam explosion (alpha mode failure)

A SIMPLIFIED APPROACH TO SOARCA BENCHMARKING

- Although performing Level-3 PRAs for the pilot plants is the best way to benchmark the SOARCA methodology, results and insights from the NUREG-1150 Study and Integrated Risk Assessment for LaSalle, together with more recent advances in understanding of the severe accident issues and containment failure mechanisms, could be used for developing a simplified, yet systematic and defensible, approach to benchmark many aspects of SOARCA.

Elements of the Proposed Approach to Benchmark SOARCA



Impact of current knowledge and understanding of early containment failure on NUREG-1150 results for the conditional probability of accident progression bins at Surry

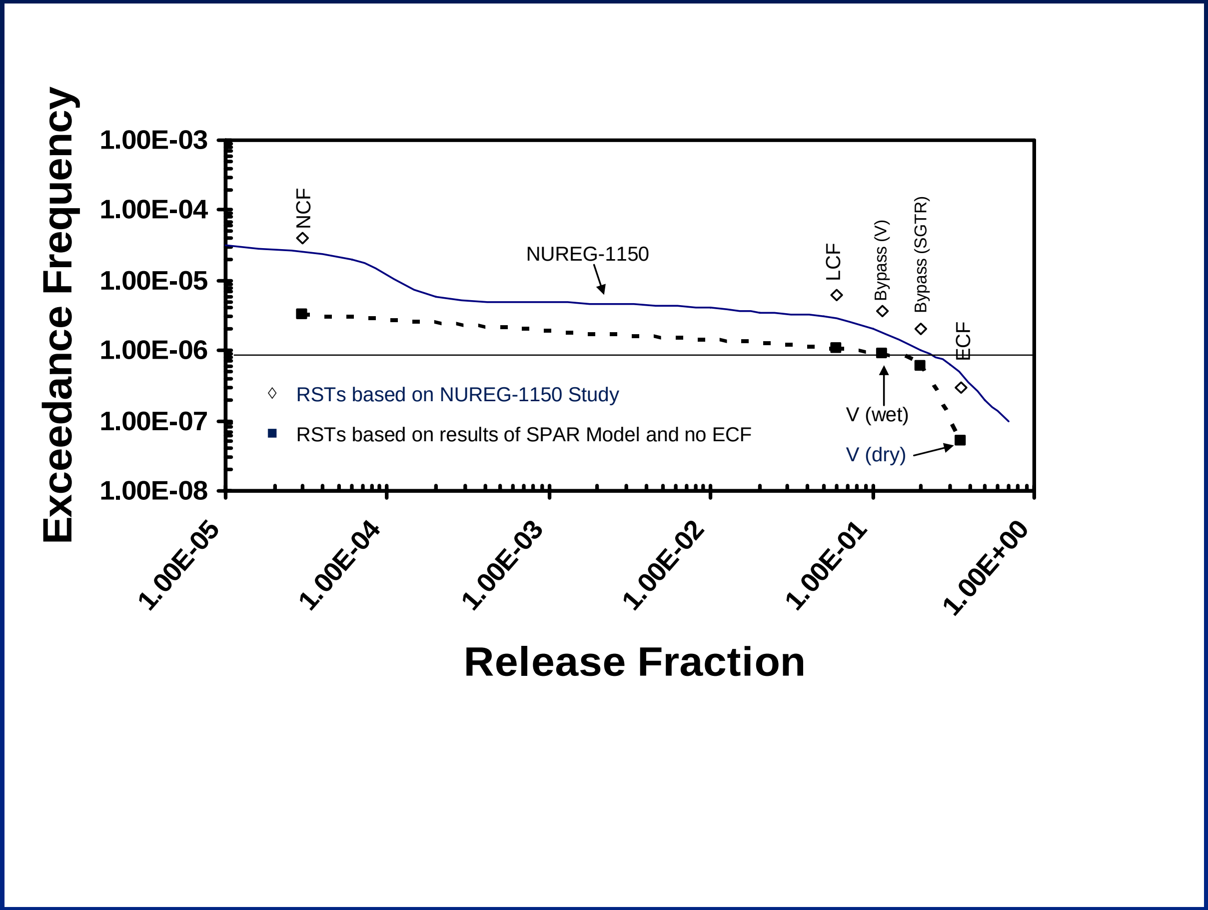
Summary Accident progression Bin Group	Summary PDS Group (Mean Core Damage Frequency)							
	Internal initiators (4.1E-05)						Fire (1.1E-05)	Seismic LLNL (1.9E-04)
	LOSP (2.8E-05)	ATWS (1.4E-06)	Transients (1.8E-06)	LOCAs (6.1E-06)	ISLOCA (1.6E-06)	SGTR (1.8E-06)		
Early CF	-- (0.008)[(a)]	-- (0.003)	-- (0.001)	-- (0.006)			-- (0.018)	0.082 (0.096)
Late CF	0.084 (0.079)	0.046 (0.046)	0.014 (0.013)	0.056 (0.055)			0.305 (0.292)	0.288 (0.280)
Bypass	(0.003)	(0.078)	(0.007)		(1.0)	(1.0)		(0.001)
No CF	0.913 (0.909)	0.876 (0.873)	0.979 (0.979)	0.944 (0.939)			0.695 (0.690)	0.630 (0.624)

(a) Numbers in parentheses are the results of the NUREG-1150 Study.

Frequencies and Magnitudes of Iodine Releases for Representative Source Terms for Surry (Internal Initiators)

Release Category	Summary PDS Group	Containment Failure Time	Containment Failure Mode	Frequency		Fractional Release for Iodine Group
				Based on NUREG-1150 Study	Revised Based on Results of SPAR Model and no Early Failure of Cont.	
RSUR1	LOSP	CF at VB (ECF)	Rupture	2.9E-07	----	0.35
RSUR2	LOSP	Late CF (LCF)	Leak	2.4E-06	1.5E-07	0.06
RSUR3	LOSP	No CF (NCF)	No CF	3.3E-05	1.95E-06	3.E-05
RSUR4	Bypass (V)	NCF	Bypass	1.6E-06 Wet (~85%) Dry (~15%)	3.5E-07 Wet (~3.0E-07) Dry (~5.0E-08)	0.115 0.115 (Wet) 0.37 (Dry)
RSUR5	Bypass (SGTRs)	NCF	Bypass	1.8E-06	5.5E-07	0.2

Comparison of frequency distribution (CCDF) of iodine release predicted by NUREG-1150 Study for Surry with that obtained from the results of SPAR model and the recent insights on early containment failure mechanisms (Internal Events)



Summary and Conclusion

- An overview of major contributions to consequence assessment was presented to provide historical perspectives and insights on previous state-of-the-art analyses of the consequences of severe reactor accidents
- It is feasible to use the results and insights from the NUREG-1150 Study and Integrated Risk Assessment for LaSalle, together with more recent advances in understanding of the severe accident issues and containment failure mechanisms, and develop a simplified, yet systematic and defensible, approach to benchmark many aspects of SOARCA