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UNITED STATES NUCLEAR REGULATORY COMMISSION'S
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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568TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY

DECEMBER 3, 2009

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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., Mario Bonaca, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

MARIO V. BONACA, Chairman

SAID I. ABDEL-KHALIK, Vice Chairman

J. SAM ARMIJO, Member-at-Large

GEORGE E. APOSTOLAKIS

SANJOY BANERJEE

DENNIS C. BLEY

CHARLES H. BROWN, JR.

MICHAEL CORRADINI

COMMITTEE MEMBERS PRESENT (Continued):

OTTO L. MAYNARD

HAROLD B. RAY

MICHAEL T. RYAN

WILLIAM J. SHACK

JOHN D. SIEBER

JOHN W. STETKAR

NRC STAFF PRESENT:

BRIAN HOLIAN

RICHARD PLASSE

ANN MARIE STONE

DUC NGUYEN

SUNIL WEERAKKODY

STEVE LAUR

HARRY BARRETT

PAUL LAIN

ALEX KLEIN

DONNIE HARRISON

EDWIN HACKETT

JOHN McKIRGAN

HANRY WAGAGE

ALLEN NOTAFRANCESCO

AMY CUBBAGE

ANTONIO DIAS

NRC STAFF PRESENT (Continued):

KHOI NGUYEN

ZENA ABDULLAHI

RUSS SYDNOR

ALSO PRESENT:

MARK SCHMEL

GENE ECKHOLT

RICHARD PEARSON

STEVE SKOYEN

JOE RUETHER

TOM DOWNING

JEFF GORMAN

DAN NAUS

WAYNE MARQUINO

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Adjourn

P R O C E E D I N G S

(8:29 a.m.)

CHAIRMAN BONACA: Good morning. The meeting will now come to order.

This is the first day of the 568th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following:

License renewal application for the Prairie Island Nuclear Generating Plants, Units 1 and 2;

Draft final Regulatory Guide 1.205, "Risk-informed, Performance-Based Fire Protection for Existing Light-water Nuclear Power Plants," and draft final Standard Review Plan, Section 9.5.1.2, "Risk-informed Performance-based Fire Protection";

Long-term core cooling approach for the economic simplified boiling water reactor design;

Draft final Revision 1 to Regulatory Guide 1.151, DG-1178, "Instrument Sensing Lines";

Subcommittee reports;

And preparation of ACRS reports.

Portions of the sessions related to long-term cooling for the ABWR design may be closed to protect information that is proprietary to GEH.

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

I have received no written comment or request for to make oral statements from members of the public regarding today's sessions. There will be several people from GEH on the phone bridgeline to listen to the discussion regarding long-term cooling for the ESBWR design. At the introduction of the meeting the phone will be placed in a listening in mode during the presentation and committee discussions.

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

I will begin with some items of current interest. Mr. Otto Maynard, who has been with the ACRS since January 30, 2006, will be leaving the Committee at the end of his term, which expires on January 29, 2010. For the last four years, Mr. Maynard made numerous contributions to the ACRS reviews specifically in the area of operating experience, license renewal, and performance-based regulation.

He was also the first Chairman of the U.S. ABWR Subcommittee. His valuable contributions, dedication and professionalism are very much appreciated. His technical expertise and camaraderie will be surely missed.

Thank you for your support in these four years.

MEMBER MAYNARD: Okay. Thank you.

(Applause.)

CHAIRMAN BONACA: Dr. John Flack has been with the Agency for 27 years, of which about seven years has been with the ACRS and ACNW. He is now retiring at the end of December 2009. During his tenure at the ACRS, he has provided outstanding technical support to the committee in its review of numerous matters, including safety culture and fuel cycle facilities.

Dr. Flack also expertly supported the ACNW in the areas of spent nuclear fuel pre-processing and fabrication facilities, risk-informing nuclear materials, and waste processes, and the review of long-term research activities. His education, hard work, professionalism, attention to details and willingness to accept additional responsibilities are very much appreciated.

Thank you and good luck in continuing your future endeavors.

(Applause.)

CHAIRMAN BONACA: And then Mr. Michael Lee, who has been with the ACRS and ACNW for about nine years will be moving to the Office of Federal and State of Materials and Environmental Monitoring Programs, FSME by late December 2009. During his tenure on the ACRS he provided technical support to the Committee in its review of several matters, including the AP-1000 amendment, the associated COL applications, and related seismic design issues.

Previously Mr. Lee supported the ACNW in the areas of low level radioactive waste management, spent fuel transportation, and civil engineering issues for Yucca Mountain. His in depth knowledge of the regulatory processes and technical support to the Committee reviewing several complex technical issues are much appreciated. We wish h good luck on his future endeavors.

(Applause.)

CHAIRMAN BONACA: Okay. Finally, this is

the end of the people leaving the ACRS. So before we move on to the agenda, I would like to point out that there has been significant effort to build another room which parallels this room. You're familiar with that. Officially it has not been used, and so we'll use it, but what's going to happen, at 12:30 we're going to have the ribbon cutting ceremony for that room, and the Chairman of the Commission will come and participate in the ribbon cutting. So if the meeting bumps into 12:30, we will just take a break at that point and then come back after lunch or we'll decide then depending on where we are with the agenda.

And this is the last point I have to make. We will move now to the items on the agenda, and the first one is the license renewal application for the Prairie Island Nuclear Generating Plant, Units 1 and 2, and Mr. Harold Ray is going to take us through the presentations by the licensee and the ACRS staff.

MEMBER RAY: Thank you, Mr. Chairman.

As you say, we are going to review here the license renewal application of Prairie Island Units 1 and 2. The Subcommittee had the benefit of meeting with the Applicant and staff in July, July 7th meeting, and follow-up items from that meeting are listed in the schedule that's before you there either in the items to be touched upon in the Applicant presentation or in the subsequent staff presentation.

Let me just make one introductory comment about one of the SER open items now closed, but also a matter that was discussed at the Subcommittee that members of the Committee may want to follow more closely. This is a plant which has had intermittent leakage of borated water within containment, specifically during refueling outages when the refueling canal is flooded up.

The effort to locate and arrest that leakage and prevent it from continuing is part of the story, but the more interesting part of the story, I believe is how the concern that may or may not exist with regard to the consequences of that leakage have been addressed. A lot of discussion has gone on in writing as well as in meetings about whether this should or should not be a concern, but at the end of the day, the matter is at least closed in the SER, as you'll hear, by measures that the Applicant has committed to take that address the effects potentially on the concrete, on the reinforcing steel, and on the containment liner plate, each of those individually.

The program to monitor, of course, is under structural monitoring program, as well as for the containment boundary, Section 11 program. So that at least the focus of my attention has been on -- and I know the staff has closed now the open item on the basis of measures that the Applicant will be taking to address each of those three areas of potential effects of this leakage.

There are several other items here listed. I won't go into each of them because they'll be touched upon as you see in the agenda. And with that I'll turn it over to Brian Holian to introduce the staff and proceed.

MR. HOLIAN: Good. Thank you.

Good morning. My name is Brian Holian. I'm the Division Director for the Division of License Renewal at NRR, and we are here to discuss Prairie Island today.

I'll do brief introductions, and the agenda is that the licensee will take the bulk of the presentation and address the open items and their resolution, and then the staff will comment on them also.

To my left is Mr. Rick Plasse. He has been the project manager for Prairie Island the entire time, and he will be doing the bulk of the presentation for the staff when we are up.

To my right is Mr. Dave Wrona. He is the Branch Chief responsible for the Prairie Island and other reviews in license renewal.

Also in the audience there are other Branch Chiefs and technical staff from NRR and the Division of License Renewal who you will hear from with questions or in response to questions as needed. I'd like to highlight Dr. Sam Lee, the Deputy in the Division of License Renewal and also in from Region 3 today is the Branch Chief from the Division of Reactor Safety, Ann Marie Stone right behind me.

One other item besides the open items I'd just like to comment on is Prairie Island was the first plant that we had a Memorandum of Understanding with, with the Prairie Island Indian community to deal primarily with environmental issues. They had areas of expertise and items like environmental justice, archeology, and that has worked very well. We have worked with them as kind of a cooperating agency status, and in reviewing those items in a close manner, and they were able to take the time to give us data and information that they had.

So I just wanted to highlight that to the Committee.

With that I will turn it over to Mark

Schmel, Site Vice President for Prairie Island.

MR. SCHMEL: Thank you.

My name is Mark Schmel. I'm a Site Vice President, Prairie Island. To my left is Mr. Gene Eckholt. He is the license renewal project manager. To my right is Steve Skoyen. He is the engineering programs manager.

The license renewal project team and subject matter experts are sprinkled throughout the crowd here that can provide additional information should we need it.

And we are here today to provide responses to the follow-up issues identified during the Subcommittee meetings and address questions in support of license renewal.

The agenda, the site description, Mr. Eckholt will carry us through that, and then we will turn it over to the ACRS License Renewal Subcommittee follow-up items, which will be handled both by Steve and Gene, and then we'll open up to any questions at the end. We will answer questions as they go along or any way you would like to handle it.

So with that I'll turn it over to Mr. Eckholt, and he will take us through the site description.

MR. ECKHOLT: Good morning. I'll provide a little background information on the prevailing site and the plant design. The other state's power company in Minnesota is the plant owner, license holder, and operator of the Prairie Island units. Northern States Power, Minnesota is a subsidiary of Xcel Energy. The plant is physically located southeast of the Minneapolis-St. Paul metropolitan area on the Mississippi River.

The construction permits for the two units was issued in June of 1968. The operating licenses were issued in August of 1973 for Unit 1 and October of 1974 for Unit 2, and of course, then those licenses expire 40 years later in 2013 and 2014.

The license renewal application to extend those licenses an additional 20 years was submitted in April of 2008.

A little design information on the plant. Both units are two-loop PWR units, 1,650 megawatts thermal, 575 megawatts electrical per unit. Westinghouse was the NSSS vendor. The architectural engineer was Pioneer Service and Engineering.

Cooling for the plant is provided through a once through cooling system from the Mississippi River. It is supplemented during the summer months by four mechanical draft cooking towers.

The ultimate heat sink is the Mississippi River through what we call the cooling water system. You may be more familiar with the term "service water system."

Because containment is pertinent to the cavity leakage and because the containment design is a little unique for PWR, I'll spend just a couple of minutes here describing the containment design. If you'll bear with me for a second here, I'll get the drawings.

Prairie Island uses a dual containment design. There is a steel vessel with a limited leakage concrete shield building around it. There's about a five foot annulus around the sides between it. The steel vessel provides the primary containment pressure boundary. The lower head is encased in concrete on both sides, as you can see in the drawing.

Because it is the primary pressure boundary without any concrete backing it up for support, the wall thickness is much thicker than most PWR vessels. The bottom head and side walls are an inch and a half thick. The top dome is three-quarters of an inch.

MEMBER CORRADINI: What is the design

pressure system?

MR. ECKHOLT: Richard?

MR. PEARSON: The question is what is the design pressure?

MEMBER CORRADINI: yes.

MR. PEARSON: And it is about 46, 47 pounds psig.

MEMBER CORRADINI: Thank you.

MEMBER RAY: Identify yourself, please.

MR. PEARSON: Oh, excuse me. I'm Richard Pearson from Prairie Island, the License Renewal Group.

MEMBER SHACK: What does limited leakage mean?

MR. ECKHOLT: Maybe Richard can address that while he is there.

MR. PEARSON: The reactor containment vessel is, of course, very tight leakage, and that's against which an integrated leak rate test is done. The shield building is limited leakage in that it's a secondary type of containment. We actually under accident conditions have a system that draws a slight vacuum on that annulus space, and so that any leakage that goes out of the shield building is going to come instead of going out.

The shield building has concrete block shield walls for the equipment hatch opening. It also has boundaries that go into the auxiliary building, and those types of things then are maintained under vacuum under accident condition.

MEMBER SHACK: But there is no liner of any sort?

MR. PEARSON: No, there is no liner of any sort. The shield building is strictly concrete. The containment vessel is steel.

MEMBER CORRADINI: So just for the sake of comparisons, so it's a similar design to Kewanee and Ginna?

PARTICIPANT: Correct.

MR. PEARSON: Well, not Ginna, but Kewanee and Sorry Island are sister plants designed by the same people. St. Lucie has a similar design. Oh, they did a much thicker wall in order to reduce the size of their containment.

MEMBER CORRADINI: Thank you.

But maybe to follow on Bill's question because I just assumed, under any sort of accident conditions, you will have the primary comment. The steel shell is your leakage barrier.

MR. PEARSON: The steel shell--

MEMBER CORRADINI: -- for 10 CFR 100.

MR. PEARSON: That is correct.

MEMBER CORRADINI: Okay. Thank you.

MR. ECKHOLT: Any other questions?

The other thing to note is the containment vessel wall is thicker around penetrations. That's pertinent when we get to discussion of the ECCS sump, the RHR pipes penetrant that contain the bare walls about three and a half inches thick there. We will be discussing that area shortly.

At this time we're going to move on to address the follow-up items on the License Renewal Subcommittee meeting. We'll be addressing four: refueling cavity leakage, condensate storage, tank examinations, and two items in the underground voltage cables, manhole inspection interval, and the pact on these conditions.

At this point I'd like to turn it over to Steve Skoyen to discuss refueling cavity leakage.

MR. SKOYEN: With respect to the fuel cavity leakage, I'm going to go over a brief history of the issue or what caused and associated corrective actions, monitoring and assessment actions that we have been taking, the long-term aging management, and evaluation of any potential degradation.

We've experienced intermittent cavity leakage on both units sine the late 1980s. The estimated leak rate is one to two gallons per hour. That was based upon measurements that were taken prior to any mitigating actions.

Most commonly observed in the ECCS sump and the regenerative heat exchanger room; that room is located directly under a refueling cavity.

We've used several sealing methods in the past. First, we went with an insta-coat material, strippable coating. We later moved into using a caulking material as we kind of focused in on where the leakage was coming from. Those were inconsistent and were very dependent upon the completeness and the quality of how they were applied.

As a result, the increased focus on long-term aging management of this issue and on the containment structure is it made it clear that we needed to have a permanent solution to this issue. Thereby we initiated a root cause in early 2009 to identify the cause as well as a permanent solution.

MEMBER CORRADINI: I think you said it, but just to make sure I understand, so it is not during operation. It's during refueling where you filled the transfer region; is that correct?

MR. SKOYEN: Only when the refueling cavity is flooded.

MEMBER CORRADINI: Okay. Thank you.

MR. SKOYEN: Is it of concern.

MEMBER SIEBER: Do you use a removable seal between the reactor vessel flange and the floor of the cavity, right?

MR. SKOYEN: Yes, we do.

MEMBER SIEBER: And that's where the leakage is?

MR. SKOYEN: No. The leakage that we're concerned with is actually in the lower cavity.

MEMBER SIEBER: I'm sure you'll get to it.

MR. SKOYEN: Yes, we'll be discussing that in detail.

The slide currently up on the screen identifies the two locations where we commonly see leakage if we are going to have that. They include both the ECCS sump and the regen. heat exchanger room. The path to the ECCS sump, once the water is underneath the refueling cavity liner, can travel through the construction joint between the floor of the transfer pit and the wall behind the transfer to the inner wall of the containment vessel.

Once it reaches that point, it can travel down horizontally between the containment vessel and the concrete. Once it is in this area, the thinnest point is the grout in the ECCS sump, and that's where we actually see the leakage if we're going to have it in that location.

The path from the regenerative heat exchanger room, once the leakage gets under the liner in that location, it can follow hairline cracks in the concrete and then shows up when it seeps through the ceiling and the walls in that particular room.

MEMBER BANERJEE: Does the water coming into the ECCS sump carry any particles with it?

MR. SKOYEN: We verified that it's refueling cavity water, but a boron concentration. We have also tested it for iron, and it is extremely low.

MEMBER BANERJEE: So there is no suspended real particles or anything.

MR. SKOYEN: No.

MEMBER BANERJEE: It's just clean water, correct?

MR. SKOYEN: Refueling cavity water.

MEMBER SHACK: Have you measured the pH of that water?

MR. SKOYEN: Yes, we have. The most recent leakage that we had during our fall 2009 outage, the pH of the water that came through the ceiling in the regen. heat exchanger room was 8.56.

MEMBER BANERJEE: Was how much?

MEMBER SHACK: Say that one again.

MR. SKOYEN: Eight, point, five, six.

(Laughter.)

MEMBER BANERJEE: It sounded like .56.

MR. SKOYEN: Oh, I'm sorry. I'm so sorry.

MEMBER CORRADINI: That was the pH measured at the leak.

MR. SKOYEN: Correct.

MEMBER CORRADINI: What's the pH of the water you have into the cavity that's leaking through the path?

MR. SKOYEN: I believe that's closer to on the order of five.

MR. DOWNING: Yes, that's correct. It's close to five.

MEMBER RAY: You have to stand up and identify yourself, please.

MR. DOWNING: My name is Tom Downing. I work at Prairie Island as the ISI engineer, and the pH of the refueling cavity water, I believe, is in the realm of five.

MR. SKOYEN: We completed our root cause

evaluations previously mentioned in april 2009. As a result of that root cause evaluation, we determined that the sources of the leakage were long in anchor bolts where they protrude through the floor embedment plates for the reactor vessel internal stance and the rod control cluster assembly change fixture, both on the floor of the lower cavity and in the transfer canal itself.

MEMBER CORRADINI: So I guess I'm not familiar with your verbiage. So it's where you put the stuff when you're refueling, not the support directly, but it's all the lay-down support structure.

MR. SKOYEN: That is correct.

MEMBER CORRADINI: Okay. And the plating between the structure. Okay.

MR. ECKHOLT: We've got a drawing coming up that will show.

MR. SKOYEN: We reached that conclusion based upon a good correlation between ceiling in those areas and the absence of leakage, as well as an analysis of the design. That revealed that a seal well, which we'll show in a later slide, if that fails, an anchor bolt then could cause a leak where flow could go past an anchor bolt.

We also completed an evaluation of any

potential degradation that could have occurred based upon the cavity leakage that has occurred over the years, and that concluded that the exposure of the containment vessel and structures to refueling cavity water has not had an adverse pact on their ability to meet design requirements.

What's shown on this slide is a typical reactor vessel internal stand support as well as an RCC change fixture support. The bolts which you'll see coming up through there to attach those stands actually come through the embedment plates.

The red material that you see in the picture is the caulk that we've been utilizing to seal between the nuts and between the embedment and base plates. That was a material that we put on at the beginning of the outage and then remove at the end of the outage.

MEMBER STETKAR: You mentioned earlier in the questioning that you've had leakage this fall in this year's outage also.

MR. SKOYEN: We'll be talking more about that when we get a later slide.

MEMBER STETKAR: Thanks.

MR. SKOYEN: The original embedment plate construction is show on this picture, and I'd like to point out the existing seal weld. If that failed, you can see that there is a direct path that can go then to the concrete underneath.

The two paths that it could take if the weld fails, one would be along the threads of the stud where it goes through the embedment plate. The other path would be between the embedment plate and the base plate.

Next slide.

During the fall of 2009, we took corrective actions based upon our root cause to permanently fix these locations. We removed the existing nuts, replaced them with blind nuts. The blind nuts were then seal welded to the base plate. The seal weld was applied also between the base plate and the embedment plate.

To insure the quality integrity as well, we perform both a visual examination and a dye penetrant examination.

The finished plat, as an example, this is an internal stand support, and you can see the blind nut, the seal weld around the blind nuts, and then the seal weld between the base plate and the embedment plate.

The repair of the floor embedment plates has eliminated 95 to 97.5 percent of the leakage that we had historically experienced. The ECS sump did not show any leakage in salvage. So we know that, based upon that, we are confident that none of it reached the actual containment vessel itself.

We only observed minor leakage on the ceiling of the regen. heat exchanger room. That appeared after the cavity was flooded for approximately 14 days, and is estimated to be .05 gallons per hour, or about seven drops per minute.

We believe that to be a different source of leakage between the floor embedment plates, but we'll go further in a later slide.

MEMBER SIEBER: I have a question. In the bolting ISI program, do you examine these bolts as part of that program?

MR. SKOYEN: These bolts are not part of the ISI program.

MEMBER SIEBER: With this repair you can't examine them.

MR. SKOYEN: That's correct.

MEMBER SIEBER: Typically you would shoot UT down the center line of the bolt, the cracks and the --

MR. SKOYEN: It is some sort of a --

MEMBER SIEBER: A probe now.

MR. SKOYEN: Correct, and to remove the stands in the future. If that's necessary, we'll have to remove the seal welds.

MEMBER SIEBER: Right. Thanks.

MEMBER CORRADINI: I'm sorry. You answered Jack. So you're saying if necessary you can go in and take out what you showed as a cross-section and redo it.

MR. SKOYEN: That's correct.

MEMBER CORRADINI: Okay.

MR. SKOYEN: As mentioned previously, we have no evidence of leakage having reached the containment vessel itself or the steel pressure vessel. We did not have any leakage in the ECCS sump and noticed no wetness or indication coming through in that area. That's been one of our more consistent indicators of leakage.

There was no leakage at the intersection of the transfer tube and containment vessel concrete. Though we haven't seen leakage there in some time, there is evidence that it has leaked there in the past.

We also only experienced minor leakage observed in the regen. heat exchanger room, and it was very responsive to cavity level. As soon as we lowered cavity level, the leakage essentially stopped, indicating that there wasn't probably enough pressure under the cavity liner to push it up and along the transfer tube.

We went into our fall 2009 outage with some additional inspection and testing that we were going to perform to further confirm that we understood the cause of the leakage. We performed vacuum box testing of the refueling cavity and liner plate in the lower cavity, all of those seal welds and identified no leakage. We also went approximately six feet up the walls in the lower cavity.

We performed NDE of the transfer tube welds. It did not identify any indications. That included both dye penetrant and visual inspection where we could not reach there to do the dye penetrant examination.

Additionally, we also did inspection of the lower cavity to look for any depressions or socked areas that would be indicative of a washout, and none were identified.

As a result of the continued leakage that we noticed in the regen. heat exchanger room, we performed some of the expanded inspections, and that included NDE of the liner plate, liner to floor embedment fillet welds. Those had been done previously, but it had been approximately ten years. So we wanted to validate that those welds still were good.

We did identify one porosity indications not believed to be a likely source of leakage because that's a multiple pass weld, and this was on the surface. That weld will, however, be repaired during our next Unit 1 refueling outage.

We also are evaluating the source of the remaining Unit 1 leakage. We believe that it's likely to be the RCC guide box wall embedment plates. We fixed the RCC change fixture flow embedment plates. These are actually on the wall itself. The design is very similar to the floor embedment plates, where a bolt protrudes through the embedment plate where the seal weld, if it fails, could be a path for leakage.

This had been an item that was identified in our root cause as a potential source of a leakage, but given the correlation that we had between ceiling of the embedment plates on the floor and the absence of leakage, it was not repaired during this Unit 1 outage.

Both of these areas are recognized as a

vulnerability and will be repaired during our next Unit 1 and Unit 2 refueling outages.

MEMBER SIEBER: Now, the materials of these various embedment plates and support structures that are attached to it, what is that material, stainless?

MR. SKOYEN: The type --

MR. DOWNING: Yes, my name is Tom Downing, and I'm from the Prairie Island plant, and I understand the question is what are the materials of the embedment plates.

MEMBER SIEBER: Yes, and the structures attached to it.

MR. DOWNING: Right. All of the materials in the refueling cavity, at least the liner, the embedment plate, the anchor bolts are 300 series stainless steel. My recollection is that they are 304 stainless steel.

MEMBER SIEBER: Okay. Thank you.

MR. SKOYEN: We also are realizing the existing RCE that we completed this past spring to determine if there are any other potential leakage sources and any additional inspections that we need to undertake prior to our next Unit 1 and Unit 2 refueling outages.

During our spring 2010 Unit 2 outage, we will be repairing the reactor vessel internal stance, RCCA change fixture for embedment plates, as we did with Unit 1 in the fall of this year. We will also be repairing the RCCA guide box for all embedment plates and performing an NDE of the embedment plate to liner welds at that location.

We will be performing a nondestructive examination of the fuel transfer tube welds as we did in Unit 1, vacuum box testing of the refueling cavity liner plate seam welds; again, the same thing we did in Unit 1, and then also a nondestructive examination of the liner to flow embedment plate fill welds, and then any other inspections or refers that result from our evaluation revision.

From 2011 Unit 1 outage, we will be preparing the RCCA guide box flow embedment plates. We do recognize those as a possible source of leakage. We'll be repairing the liner to flow embedment plate fillet weld porosity indication, and again, any other inspections and repairs resulting from evaluation of our unit, one experience this fall and anything that comes out of our Unit 2 experience next spring.

We have monitored and assessed the impact over the years of the leakage that has occurred and what impact it could have. There have been multiple occasions we have removed the grout from the ECCS sump in both our Unit 1 and Unit 2. This was done prior to 2009 for both units. Grout was removed. The wall thickness measurements were at or above ASTM specifications, and we noted no corrosion of the containment vessel and no pitting.

This past fall we once again took the grout out of the sump in Unit 1, and again, measured the wall thickness. All readings were at or above ASTM specifications, and no corrosion of the rebar or containment vessel was noted.

MEMBER ARMIJO: Could you go back to that figure that we looked upon that had a cross-section and just explain what we're looking at there?

MR. SKOYEN: The pipe, the ECCS suction line, is for the RHR suction and you go on to emergency core installation. The sump itself is a concrete sump, and the lower elevation of containment that would collect the water in the event of a LOCA.

MEMBER ARMIJO: What does the blue represent?

MR. SKOYEN: The blue represents the grout.

MEMBER ARMIJO: The group. That's what

you removed?

MR. SKOYEN: That's correct.

MEMBER ARMIJO: Okay.

MR. SKOYEN: Not all of it. We removed a section.

MEMBER ARMIJO: Okay, and then you did inspection of the underlying material.

MR. SKOYEN: Steel containment vessel. That's correct.

MR. ECKHOLT: Okay. There are pictures on that, right?

MR. SKOYEN: Yes. And we didn't expect it, but we did find rebar when we did the excavation this past fall, which provided us the opportunity to make an assessment of that as well. We didn't find any degradation of the grout. The ribs on the rebar, intact, and we didn't note any corrosion on the rebar.

The containment vessel itself was mentioned previously. Wall thickness was at or above specification, and we didn't observe any pitting as a result of any corrosion. And we did not notice any wet areas or leakage.

MEMBER ARMIJO: Why is rebar there? Why isn't that just solid field containment?

MEMBER CORRADINI: It comes up from the

concrete, I assume.

MR. SKOYEN: Correct.

MEMBER ARMIJO: Maybe I had better look at that schedule.

MEMBER CORRADINI: When you got back to the cross-sectional cartoon, I think that will help, Sam.

MEMBER ARMIJO: Yeah, just show me what we're looking at on that cross-section.

MEMBER SIEBER: That's the concrete.

MEMBER CORRADINI: The yellow is where? That's, I guess, what --

MEMBER ARMIJO: Yeah, that's --

MR. ECKHOLT: I think the grout was taken from alongside of the ECCS pipe.

MEMBER ARMIJO: Oh, okay. So there is concrete around it.

MR. ECKHOLT: Correct.

MEMBER ARMIJO: All right.

MEMBER SIEBER: Now, this sump, have you gone the GSI 191 sump strainer?

MR. SKOYEN: Yes, and that's the elbow you see on top of the sump leads to the strainers themselves.

MEMBER SIEBER: It looks like a pretty

small sump.

MR. SKOYEN: It's fairly large.

MEMBER SIEBER: Oh, okay.

MR. SKOYEN: And the strainer capacity is several hundred square feet.

MEMBER STETKAR: That's puny.

MEMBER BANERJEE: Very small, and you're upgrading the strainers or --

MEMBER SIEBER: No, he said they did it.

MR. SKOYEN: That's been completed.

MEMBER SIEBER: I wouldn't mind looking at that from the details. Maybe staff in their submittal has the description of what's been done along with some drawings.

MEMBER SHACK: I'm quite comfortable with the notion that what is good contact between the concrete and the steel there's very little likelihood of corrosion. I'm a little concerned that if you have some sort of an open area where there's not good contact between the water and the concrete, you could have a bigger problem, and we certainly know there are situations where the concrete hasn't filled everything and you've left cavities.

There's a dominion report that had some sort of bounding assumption that you would get .25

inches of corrosion, and I just wonder what the assumptions of that analysis were.

MR. SKOYEN: The assumptions of that analysis were continually refreshed, borated water, in an area that the environment --

MEMBER SHACK: What pH and oxygen conditions?

MR. SKOYEN: Jeff.

MR. GORMAN: Jeff Gorman, Dominion Engineering.

The assumption was it is oxygenated, open to the air, and neutral pH, around seven.

MEMBER SHACK: Around seven.

MR. GORMAN: That's very conservative at an exposed surface.

MEMBER SHACK: But it might not be so conservative for an open area that was not in good contact with the concrete, but it's a bounding calculation with the seven.

MR. SKOYEN: Right, and we'll talk more about what our expected degradation would be in a later slide.

MEMBER RAY: So they've talked now about what has been done. What will come up is what's to be done, which may be more interesting.

MR. SKOYEN: We have also performed ultrasound examinations of the containment vessel from the annulus, and those would be along the path that we would have expected any leakage to have flowed. Unit 2 was last inspected in the fall of 2008, Unit 1 in the fall of 2009. The areas that we examined were from the transfer tube toward the ECCS sump, and then above and behind the ECCS sump. The wall thickness at all of those locations was at or above ASTM specifications, and what you see on the projector is the photograph from the annulus that allows us to inspect from the back side to the inside of containment.

MEMBER ARMIJO: Which side is the steel?

MR. SKOYEN: This is steel right here.

MEMBER ARMIJO: Steel on the right.

MR. SKOYEN: We do have several commitments for the next refueling outage, and each unit following embedment plate repairs. We will be removing concrete from the sump below the actual reactor vessel. That's the thinnest location, at the lowest part of containment, and Pepco will be exposing the containment vessel so that it can perform both a visual examination and ultrasonic examination to determine the thickness and validate our evaluation of potential degradation.

We're performing an assessment of both concrete and then also performing petrographic examination of any removed concrete. If any water is found at that location when we remove the concrete, that will be evaluated as well.

We will also be removing concrete sample that has been wetted by borated water, leakage from the refueling cavity over a period of time. That concrete will be tested for compression strength, and we'll also undergo petrographic examination.

We also have a commitment for the next two consecutive refueling outages in each unit following our embedment plate repairs. We will be monitoring those areas that have previously exhibited leakage to confirm that the leakage has not recurred.

MR. ECKHOLT: And just to point out, these commitments will be completed prior to the period of extended operation.

MEMBER MAYNARD: Could you go back just a minute? Exactly what concrete are you removing? It says removal of concrete from sump below the reactor vessel.

MR. ECKHOLT: You can see at the very bottom of the drawing Sump C. You're going down through that location. That's the thinnest part of the concrete.

MR. SKOYEN: And that is between 15 and 18 inches of concrete that has to be removed.

MEMBER SIEBER: Okay.

MEMBER RAY: So all of the debate about what may or may not have happened is intended to be verified here.

MR. SKOYEN: With respect to long-term aging management, we're going to continue to manage aging in the constrainment structure and the vessel using the structure's monitoring program, as well as the ASME Section 11, Subsection IWE Program.

Any items that are found, of course, will be put into our corrective action program for evaluation with new corrective actions being issued.

As mentioned previously, we have performed a comprehensive evaluation of the potential for degradation. The steel containment vessel, the reinforced concrete, the evaluation concluded that any potential corrosion of the containment vessel behind the concrete in the areas that have been wetted by refueling cavity water would be minor.

It also concluded that there has been no significant effect on the reinforced concrete that has been wetted by refueling cavity water.

MEMBER SIEBER: I would like to ask a couple of questions. You can put it up.

MR. SKOYEN: Okay. G.

MEMBER SIEBER: Now, you get access, personnel access, in that very bottom sump under the reactor vessel. Is there a hatch or some way in there?

MR. SKOYEN: There is a hatch.

MEMBER SIEBER: How often is that inspected for leakage down there?

MR. SKOYEN: The Sump Charlie reactor vessel -- that's the name for it -- is gone into every outage.

MEMBER SIEBER: Okay. What is the clearance between the vessel and the concrete along the side wall?

MR. SKOYEN: The side wall?

MEMBER SIEBER: Yeah.

MR. SKOYEN: The annulus area?

MEMBER SIEBER: Right.

MEMBER CORRADINI: Between the vessel and that concrete right there.

MEMBER SIEBER: What's the clearance there?

MR. SKOYEN: I'll refer to Tom Downing to answer that question.

MR. DOWNING: Hi. My name is Tom Downing, ISI engineer at the Prairie Island plant. I understand the question is how much clearance is there between the reactor vessel and the side wall. Essentially there is no clearance. Actually there is duct work for reactor vessel cooling that goes up against the wall. So you can't really see between the reactor vessel.

The drawings indicate it's in the realm of inches. You can see the side of the reactor vessel from up on the upper level of the refueling cavity when you take the sand plug covers off and look down there, but again, it's just some number of inches between the insulation on the reactor vessel and the concrete.

MEMBER SIEBER: So leakage from the refueling cavity sealed to the flange area of the vessel, you would not be able to see a major portion of that pathway; is that correct?

MR. DOWNING: Well, that leakage between the reactor vessel and the refueling cavity does make its way down into Sump C. That duct work is not watertight, and so it does come down the wall, and it collects in the sump.

MEMBER SIEBER: Okay. You're hoping that it does.

MR. DOWNING: Well, every time we've had leakage, a sample of covered leak or any other kind of leak, the large majority of that water, and we believe all the water, does make its way into that sump. We do not believe that that is a source of refuel cavity leakage that we see over in the ECCS sump, for example.

MEMBER SIEBER: You don't have a neutron shield tank, right?

MR. DOWNING: I'm sorry. Could you repeat the question?

MEMBER SIEBER: You don't have a neutron shield tank or do you have insulation on the outside of the vessel?

MR. DOWNING: No, there is just stainless steel insulation on the outside of the vessel.

MEMBER SIEBER: Okay. Thanks.

MR. SKOYEN: Just to summarize the discussion, we have found no degradation of the concrete or the steel containment vessel to date. The evaluation of any potential degradation that could have occurred indicates that it would be of low safety significance.

We do understand the situation. We are continuing to evaluate that and are committed to eliminating the refueling cavity leakage on both of our units.

MR. SCHIMMEL: I guess I would like to just jump in here and restate what Steve just said. Prairie Island is committed to managing age-related issues during the period of extended operation, and we will go after corrective actions Steve outlayed (phonetic) within his presentation.

MR. SKOYEN: Gene?

MR. ECKHOLT: At this point, if I can continue on, if there's no additional questions in that area, with the other remaining follow-up items, we'll start with the condensate storage tank examinations. During the Subcommittee meeting, members of the -- you can see a slice of the Subcommittee -- questioned our above-ground steel tanks program and our commitment to ultrasonic inspection of the bottom one of the three condensate storage tanks prior to the PEO. The concern was whether an inspection of only one tank would assure acceptability of all three tanks.

We took those comments to heart. We went back, looked at our program, and upon further evaluation we submitted a license renewal application change in August of this year, which revised the above-ground steel tanks program to include ultrasonic inspection of the bottom of all three condensate storage tanks prior to the PEO.

Next we'd like to talk about the two follow-up items related to underground medium voltage cables, the first being manhole inspection interval and the second, the impact of freeze/thaw conditions.

Again, during the Subcommittee meeting there was questions on the adequacy of our two-year inspection frequency for the manhole that's installed. That frequency is actually based on actually plant experience, and consistent with the GALL, the interval would never exceed two years.

We have one manhole in scope. We've done five inspections of that manhole sine September of 2007 and have found no signs of water intrusion or accumulation.

The design of the manhole precludes accumulation. A lot of picture here coming up next to get a better idea. The floor of the manhole is a sand-gravel combination. The soil on the Prairie Island site is very sandy. It drains very readily.

The bottom of the manhole is approximately ten feet above the water table, and the grade around the manhole opening precludes significant water intrusion. There is a crown that would keep significant rain water from running in.

Based on the design it precludes accumulation, and our experience to date based on five previous inspections, we think a two-year inspection frequency is sufficient.

MEMBER MAYNARD: You think above the water table, the normal water table, is that when the Mississippi River is up at its highest?

MR. ECKHOLT: That would be the normal water table. Obviously the water table being that close to the river would fluctuate with river level. We have initiated a change to our site flood procedure, that if we reach a certain flood level, we will go initiate the inspection of the manhole to make sure we haven't got water accumulating in case the water table would have come up

MEMBER MAYNARD: And so you do have provision in your inspection program for certain conditions you would go out and inspect.

MR. ECKHOLT: That's right.

MEMBER MAYNARD: It's not just on a

straight periodic calendar time, here I go inspect?

MR. ECKHOLT: Right.

MEMBER MAYNARD: Okay.

MEMBER RYAN: What is that criteria?

MR. ECKHOLT: Joe.

MR. RUETHER: I'm Joe Ruether. Would you repeat the question?

MEMBER RYAN: What's the criteria for that inspection? Is it a certain water level relative to the level of the cables? Is it a rise in the river water? What's the dynamics of that?

MR. RUETHER: It would be a flood condition where the water would raise the level of the bottom of the pit.

MEMBER RYAN: I'm sorry. I didn't hear you.

MR. RUETHER: It would be a flood condition where the river would be at the level of the bottom of the manhole.

MR. ECKHOLT: The criterion procedure, I believe, is based on an actual river level.

MEMBER SIEBER: Right.

MEMBER RYAN: That corresponds to the water being at the same level as the bottom of the sump or the bottom of the concrete structure?

MR. SCHIMMEL: Joe, what he asked was what kicks you in to go, I believe, to the inspection of a sump based on some other parameter that you're monitoring that says, "When I see this, I go do this." What is that?

MR. RUETHER: It is an abnormal procedure for flood. It's our flood procedure.

MR. ECKHOLT: And you would look at a given river level which is defined in that.

MEMBER RYAN: Okay. So it 's the water level in the river that kicks you into the procedure, and you would correlate that with the water level in this manhole access.

MR. RUETHER: That's correct.

MEMBER RYAN: Okay. What's the response time between the two? The river can come up two feet. How long does it take to reflect that change in elevation in the sump?

MR. SCHIMMEL: If we don't know the response to that, just say we don't know.

MR. RUETHER: I wouldn't know what the response time would be.

MEMBER RYAN: I guess I'm just trying to understand the kinetics of that. I mean, you might initiate an inspection at a point where you haven't seen all of the river rise in the location. Do you know what I mean? I'm just trying to understand that a little bit.

MR. SCHIMMEL: Typically once we hit that level on a procedure that would active the inspection, we would go out pretty much on that shift and take a look at the manhole.

MR. RUETHER: The action is actually based on predicted level. We anticipate what the level is. So this is a preparation. We're already prepared before we get to that level.

MR. SCHIMMEL: I understand your question. Your question is once you hit the conditions to go look, how long does it take you to go look at that, right?

MEMBER RYAN: Well, I'm sure that's fairly quick. You might go look and say, "Oh, it's dry," come back in two weeks and it has responded more and you're getting wet.

MR. SCHIMMEL: Fair point. Yeah.

MEMBER RYAN: So I'm just trying to understand, you know. I mean, groundwater response time -- I'm going to guess -- on the edge of the Mississippi River could be --

MEMBER SIEBER: Days.

MEMBER RYAN: -- days or weeks even depending on the time of the year.

MEMBER SIEBER: Yes. You usually don't have floods for weeks.

MEMBER RYAN: And this isn't just, you know, a question for you all. I've been dissatisfied with a lot of the generic answers about, well, we've had a two-inch rain. So we went and looked at the manholes. We did something and it was dry. So we're okay.

Well, that's maybe not true because it may be okay in two days after the rain, but two weeks after the rain it could be flooded.

So without more sophisticated understanding of the kinetics between the river and the point of inspection and the time of inspection, that's something to think about.

MR. SCHIMMEL: I understand. Fair question.

MEMBER STETKAR: Gene.

MR. ECKHOLT: Yes.

MEMBER STETKAR: As I understand it, you rerouted some cable so that this is the only manhole that now contains cables that are in scope; is that correct?

MR. ECKHOLT: That is correct.

MEMBER STETKAR: Do you know, could you tell me what cables, in scope cables in particular, are routed through this manhole, what systems, what equipment?

MR. ECKHOLT: I'll let Joe answer that one again.

MR. RUETHER: Joe Ruether.

These cables are 13.8 kV, and they're our cooling tower source for our safeguard buses. It basically has two off-site sources for safeguard buses.

MEMBER BROWN: Are they independent off-site sources?

MEMBER STETKAR: Are these the same cables? You recorded cable failures due to water intrusion in your response to Generic Letter 2007-01, and two of those cables, if I read my notes correctly here, were indeed 13.8 kV cooling tower supply cables. Are these those cables?

MR. RUETHER: These are replacement cables. We've dug a new trench and so this was installed in 2005.

MEMBER STETKAR: This is a new manhole.

MR. RUETHER: This is a new manhole.

MEMBER STETKAR: Oh, okay, okay, okay, okay. Because I knew you had rerouted some of the cables, and this is part of the rerouting path.

MR. RUETHER: That's correct.

MEMBER STETKAR: Okay. Thank you.

MR. ECKHOLT: Is there another question?

MEMBER RYAN: One more question about the environmental question. You say you're approximately ten feet above the water table. What's the seasonal or annual fluctuation of the water table at this location?

MR. ECKHOLT: I don't know.

MR. RUETHER: The river, this is behind the pool for Lock and Dam No. 3. So it's pretty much controlled by the dam.

MEMBER RYAN: So the water level at this location is not constant, no doubt, but is it one foot, ten feet?

MR. SCHIMMEL: He's asking about what the fluctuation of the water level is.

MR. RUETHER: Ten feet would be a food condition.

MR. SCHIMMEL: I guess our answer to this is we don't know. If you're asking about the fluctuation in the pool level, it's 674, 674.5, is what it's maintained at.

MEMBER RYAN: Again, on all of these cable questions that have come up, you know, there's some source of like a river or a lake, and it changes, and there's a response to that at the location of interest either on the top of the manhole, in the cable chase, or wherever it might be.

What I'm trying to get a feel for is how much does the water level change in the river affect the water here, and you know, in other circumstances it's how much rainfall do you get at what rate over what period of time and in what form, ice, snow, rain, and to cause the same kind of effects in the collection point in the sump.

And those environmental variables to me really determine what kind of water condition you're going to look at here in the various circumstances.

MR. ECKHOLT: A ten-foot swing in Mississippi River level is pretty significant.

MEMBER RYAN: That's a big deal, yeah.

MR. ECKHOLT: Yes.

MEMBER RYAN: It would be fairly close to the saturated water level in the ground, would be pretty much the same as in the river most of the time.

MR. SCHIMMEL: I don't believe we have the specifics that he's asking for.

MEMBER RYAN: That's okay. I think that's helpful to understand that if you're really trying to figure out is the inspection program adequate to see those conditions where we know we'll have to take action.

MEMBER MAYNARD: I'm at least glad to see a program that is based on some parameter as opposed to just a periodic --

MEMBER RYAN: Yeah. It's very rare that you're trying to tie it to the river water level. That's very helpful, but the kinetics of it could be a little bit complicated.

MEMBER STETKAR: Gene, I just want to make sure I've got the history straight. You had some cable failures. You rerouted the cables in question. The manhole, the subject manhole that we're looking at on the screen right now, is part of that new routing path.

MR. ECKHOLT: That's correct.

MEMBER STETKAR: That's correct? And you mentioned earlier that you had performed five inspections since September of 2007 and discovered no signs of water intrusion. That's of this manhole.

MR. ECKHOLT: That's correct.

MEMBER STETKAR: Okay. Thanks.

MR. ECKHOLT: Any other questions?

(No response.)

MR. ECKHOLT: The last follow-up item is there was a question asked during the subcommittee meeting related to the possible impact of freeze/thaw conditions on the aging of cable insulation. We reviewed our operating experience with Prairie Island to look for any evidence of accelerated cable insulation aging related to freeze/thaw.

We also went to some additional organizations. We went to the other Xcel Energy nuclear site, the Monticello Nuclear Generating Plant. We talked to the Xcel Energy distribution folks, which maintain extensive underground cable systems. We talked with EPRI, and we also raised the question with the NEI License Renewal Electrical Working Group.

And to all of that research and contacts with outside organizations, we found no evidence, no indication that freeze/thaw conditions have been identified as the cause of cable insulation leading to failure.

That's it. Any other questions?

CHAIRMAN BONACA: I have a question. You mentioned that as we have seen the leakage before the repairs was one to two gallons per hour, and then you told us that after the repair, the leakage in the ECCS sump was eliminated, and you had the leakage of 0.05 gallons per hour in the reactor refueling cavity.

MR. ECKHOLT: The regenerative heat exchanger room.

CHAIRMAN BONACA: The question I had was how much was the leakage in that room reduced.

MR. SKOYEN: On this particular unit, we had not observed any leakage during the prior to outages.

CHAIRMAN BONACA: Okay.

MR. SKOYEN: Now, that may be because of the location where it was actually leaking is difficult to access. It's in a lock tight red area. It's up on the mezzanine. So it's possible that it could have been dripping at that same rate during the prior two outages, but we did not have any reports of any leakage.

CHAIRMAN BONACA: Yeah. I was trying to understand by my question whether, you know, the cure that you have, I mean, in the room may not have been completely stopping the leakage and the regenerative room was affected and on target. It may not be a complete stoppage, but you know, you seem to have identified the solution.

MR. SKOYEN: We have eliminated 95, 97.5 percent of the leakage. We got the biggest single contributor by going out to the floor embedment plates. We do have a small source that remains that we'll continue to evaluate. We believe that it's likely that it's coming from the embedment plates on the --

CHAIRMAN BONACA: Yes, I understand. So you're saying about 90 percent has been stopped even for the regenerative exchanger room

MR. SKOYEN: I think that would be an accurate statement. We have been taking mitigating actions for several years. The estimate of one to two gallons per hour was taken several years ago prior to taking any mitigating action.

MEMBER MAYNARD: You said that the leakage in that area was very sensitive to the level in the refueling cavity.

MR. SKOYEN: Correct.

MEMBER MAYNARD: And what's the approximate elevation of these wall mounts? Are they close to the water line, well below the water line?

MR. SKOYEN: They are up -- from the bottom of the lower cavity up to the top one is in excess of 25 feet, and then there are different elevations as you come down. I believe there's four total.

MEMBER MAYNARD: You indicated that you thought the pressure related by the water level changes, but it also could be the flaw that is just close to the water level there, too, that you're either covering or uncover it.

MR. SKOYEN: That's correct.

MEMBER ARMIJO: Have you looked at that as a potential source?

MR. SKOYEN: At the?

MEMBER ARMIJO: At, you know, the region above the water level when the leak stops.

MR. SKOYEN: Yes, we have looked at, evaluated all of the penetrations on the cavity and in the past have vacuum boxed -- Tom, correct me if I'm wrong -- the entire cavity.

MR. DOWNING: That's correct.

MEMBER ARMIJO: Okay.

MEMBER STETKAR: I thought I heard you say that you really didn't know whether there was leakage in the heat exchanger room because nobody has been in there in a while. You discovered leakage this year. Is it only because somebody had to go in there and do work, or did you actively go looking for it?

MR. SKOYEN: No, I was actively looking for it when it was identified.

MEMBER STETKAR: Okay.

MR. SKOYEN: And we knew that the ceiling was a historical point of leakage. So rather than inspecting it from the floor -- it's about 12, 14 feet in the air -- we went up in the mezzanine area so that we could get a close visual examination, and that's when we identified.

MEMBER STETKAR: When you say the ceiling, you mean that it would be the ceiling of the room, but the bottom of the concrete area from the cavity, right?

MR. SKOYEN: That is correct.

MEMBER RAY: Okay. The next case, Brian.

MR. HOLIAN: We'll just change places.

Once again, I introduced Rick Plasse, the project manager for Prairie Island. That is Ann Marie Stone to his right, and to his left is Kent Howard, the project manager for Beaver Valley that we've just completed who will be assisting with slides.

I'll turn it over to Rick to start the presentation. Once again, on leakage, he'll cover a little bit on the staff's review of that, and I just wanted to reiterate again, as Mr. Ray did at the beginning of this session, it is minor leakage that we've seen there, especially compared to some other plants that we've had. Indian Point that we had the Subcommittee meeting on recently had upwards from 40 gallons from the refueling cavity leakage.

However, that was caught, and they were very confident they had caught that in a sump type area right around the cavity and was routed down to containment. Prairie Island was a little different in that. It was -- I can't say the word --

PARTICIPANT: Circuitous

MR. HOLIAN: Thank you.

That kind of path, and the staff spent some extra time just looking at any potential effects of that, and that's part of our effort at looking at operating experience at individual plants and make sure we pull the strings on that. So I wanted to credit some of the tech staff with those requests for additional information early on in the process that caused us to look.

With that I'll turn it over to Rick Plasse.

MR. PLASSE: Good morning. Yes, my name is Rick Plasse. I'm the project manager for Prairie

Island Nuclear Generating Plant's license renewal application.

Besides what Brian introduced, I'd like to just note a few of the staff and one of our contractors for the open items. On the waste gas tank I have Billy Rogers. He led the scoping and screening audit for the staff.

For the vessel internals program, I have Jim Medoff, who did the review of that item, and then for the structural item I have in the audience Bryce Lehman from the NRC staff, Abdul Sheikh from the NRC staff, and we also have Dr. Dan Naus from Oak Ridge National Lab. He did some work with us with respect to the concrete materials and structural engineering aspects of our review.

I also have to my right Ann Marie Stone from the region, representing the region for the regional inspection, and I've got Kent as my colleague assisting me here with the slides.

I'll go for an overview of the staff review, the inspection that the region did, and items of interest which was requested by the ACRS in addition to the open items.

The staff review, as mentioned earlier, the SER with open items was issued June 4th. We had the Subcommittee on July 7th. We had 168 RAIs issued through the process, and there were 37 safety commitments for both units as a result of the review.

The next slide.

Since the Subcommittee meeting, the staff evaluated the additional information provided by letters in May, which was on the VIP. June 5th, which was waste gas; the 24th was on the reactor cavity leakage; and then also on August 7th which we've mentioned in the Applicant's presentation, and then there was additional follow-up on the PWR VIP on August 21st.

The staff closed all three open items, and the details of that were issued on October 16th, in the final SER, and the staff came to the determination that the requirements of 54.29 alpha had been met.

Next slide.

The 71002 inspection that the region performed, they completed scoping and screening of the non-safety SSEs in the current 54 for an alpha two; consisted of physical lock-downs of systems, verified scoping and also noted material condition of the lock-downs.

They reviewed 24 of the 43 aging management programs. They reviewed the program documents, implementing procedures. They also did an entry at power in the Unit 1 containment and did a general view of the containment conditions, and in addition to that, they interviewed plant personnel as necessary as they did their review.

They completed operating experience review. That consisted of system health reports; also the corrected action. They looked at all of the corrective action reports associated with the 24 AMPs that they reviewed.

In addition, the inspection was observed by the Prairie Island Indian community, Tribal Council President. The inspection conclusions, scoping of non-safety SSEs and aging management programs are acceptable. Inspection results supported a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained.

MEMBER CORRADINI: I have just an informational question. The fourth bullet, is that under some agreement between the tribe and the state or is that informal?

MR. PLASSE: As mentioned earlier, we had a Memorandum of understanding.

MEMBER CORRADINI: With the NRC and the tribe?

MR. PLASSE: Yes, right.

MEMBER CORRADINI: Okay. Excuse me.

MR. PLASSE: And as a courtesy --

MEMBER CORRADINI: That's fine. I did not understand. Thank you.

MR. PLASSE: Okay. On the next slide, the staff, not only did we do a site aging management program review in September of '08. WE also did in-office reviews of the material. There were 43 amps for this particular facility. Fourteen were new; 29 were existing; 22 were found to be consistent with the GALL; nine were consistent with GALL with enhancement; four were consistent with GALL with exception; and two were plant specific AMPs.

With that, it resulted in three open items, which is what the next three slides are. The first one, on a reactive waste decay tank, initially the waste gas decay tanks were not classified within the scope of license renewal. The staff review determined that they should be considered within the scope of license renewal, and by letter dated June 5th, the Applicant stated the waste gas tanks had been reclassified as in scope.

The staff reviewed that scope change, including the drawings and additional equipment added for aging management review line items, and the staff found that the review was adequate and the changes were adequate, and the item was closed.

In addition there was an open item. On May 12th, the Applicant made a change, submitting the PWR VIP as a ten-element program that was reviewed by the staff. Staff completed the review of the new aging management program, and all of the associated aging management review line items, and that item is closed.

The third open item is what we basically talked about for the first portion of the meeting, was structurals monitoring program, the issue with the water seepage from the refuel cavity into the containment sumps.

The staff closed that based on the commitments made by the Applicant, and I'll just kind of speak a little bit about the commitments. We've kind of already been through them, but the Applicant committed to removing the concrete from the low point in the containment Sump Charlie below the reactor and performed UT on the vessel. The rebar concrete will also be inspected during the excavation. That is Commitment 41, and that addresses the staff's concern about possible containment vessel degradation.

The Applicant also committed to removing test concrete from known wetted areas. The Applicant will perform compression tests, as well as a petrographic exam. That is Commitment 44, and this addresses the staff's concern that the leakage may have caused concrete degradation.

Degradation identified from any of these inspections will be entered into the corrective action program and evaluated for impact on structural integrity.

With that I'll open at this time if you have any further questions for the staff on this issue.

VICE CHAIRMAN ABDEL-KHALIK: I had a question. I believe the Applicant stated that the pH of the borated water in the refueling cavity is about five, and the pH of the water collected is about 8.56. How long does it take for borated water with a pH of five in contact with concrete to reach a pH of 8.56?

MR. PLASSE: Dr. Dan Naus will.

DR. NAUS: Dan Naus, Oak Ridge National Laboratory.

We did some literature search on the effects of boric acid on concrete, and unfortunately there is not a lot available, but what is available indicates that it's not a problem. There are two references that cite this.

Generally you have a problem with acid in concrete when the pH is around three and a half or so and the pH of boric acid is on the order of four to five.

The other thing we did is some calculations using a database at Oak Ridge, and this indicated that the reaction was fairly slow, and it would be a slowing as the process goes on because of the reaction product build-up, and you would not have the continual refreshing of the calcium hydroxide.

The other thing it indicated, that the pH could be expected to be on the order of seven to eight. Now, the timing of this, I cannot give you an answer to that, but in the long term it would be seven to eight, would be our prediction. Of course, we couldn't model the kinetics, but that's the best we could do.

VICE CHAIRMAN ABDEL-KHALIK: I'm trying to get an idea about the residence time or the transit time of any water leaking from the refueling cavity, ultimately reaching the location where it is collected, and by figuring out how long it takes for the pH to change from eight to 8.56, that might give us an idea as to whether the proposed route for the leakage is reasonable or not.

DR. NAUS: I can't comment on that.

VICE CHAIRMAN ABDEL-KHALIK: Does the Applicant have any comment?

MR. DOWNING: Tom Downing.

The only thing I can add to this --

THE REPORTER: Sir, just back off a little bit.

MR. DOWNING: Oh, I'm sorry.

(Laughter.)

MR. DOWNING: And my name is Tom Downing, Prairie Island.

The only thing I can add to the discussion, that the time from we flood the cavity until the time we've seen leakage in the ECCS sump has ranged anywhere in the realm of four days to ten days. This last outage we did not detect any leakage until 15 days after a pool flood, and it never even showed up in the sump. It was just in the region room.

How much of that water was there and just got pushed or how much actually came from the refuel cavity and made its way all the way over I really don't know.

VICE CHAIRMAN ABDEL-KHALIK: Okay. Thank

you.

MEMBER RAY: Could we ask the professor to come back here?

The commitment that the Applicant has made to examine the effects potentially on the concrete in question presumably will confirm the judgment that this is not likely to be a problem, but is there anything more to be said about that testing, how it should be done, how representative it might be?

It's compressive strength, I guess, for the concrete as well as petrographic examination, which I'm not sure what all it discloses, but presumably it looks at the integrity of the concrete and the possibility that it was affected by the boric acid. But can you say anything more about the testing and how -- because, you know, we're looking at this from the standpoint of learning something about this phenomenon that we don't presently know.

DR. NAUS: Yes. As you said, the compressive strength would given an indication if it has been deteriorated by the interaction of the acid and the constituents in the concrete.

On the petrographic examinations, there's a number of tests they do to look and see if there's any chemical reactions going on, if the aggregate or the cementitious materials have deteriorated. There's a general procedure, an ASTM procedure you would follow to see if there are any chemical reactions or other effects. There's a large number of things you can look at through these examination.

MEMBER RAY: We don't have any extant data, I guess. This will be new information pretty much, as I understand.

DR. NAUS: The only data that I have found, there's some information from the Paks plants, which I believe is in Hungary. They had an area where they had some leakage of borated water, and they took the concrete out and looked at it, and there was no real indication of degradation. I would not expect any degradation of the concrete in this case because of the intermittent nature and the low volume of the fluid that's being--

MEMBER RAY: Well, it's intermittent is a hypothesis. There may be concrete where it's not intermittent conceivably because there is no drain from the lowest point where it might accumulate. So I think we assume it's intermittent. We know it's intermittent for much of the structure, but there may be some where it's not.

DR. NAUS: Right. I think when they

remove the samples and do the test you'll have a much better idea about the support, that nothing is happening to the concrete itself.

MEMBER RAY: Thank you.

MR. HOLIAN: This is Brian Holian.

Just to also interject here, you know, we're starting to see containment or concrete issues, you know, not only at some of the plants that we're pulling the strings on, individually as the plants come in with operating experience, but also just the staff is looking at, okay, what type of generic look should we do as plants continue to age or as plant continue to look at, you know, potential life beyond 60 aspects.

So, you know, License Renewal is working with a research user need that's in draft now that still has us looking towards research for similar looks and/or potential research on effects on concrete, that just being one of the items; you know, cable aging, other issues that we're going to research for.

I just wanted to mention that.

MEMBER RAY: Yeah. No, I think that's great, Brian. Thank you.

MR. PLASSE: Any other questions for the

staff on this issue?

(No response.)

MR. PLASSE: The next slide is four bullets of the items of interest from the Subcommittee. The Applicant kind of addressed these, and I have people from the staff who did the final reviews for the final SER here.

The first item on the CST UT inspections, originally they had UT bottom of one of the three CSTs prior to PEO. By letter August 7th, they provided a supplement based on the ACRS meeting and committed to UT the bottom of all three CSTs prior to the PEO. The staff found that acceptable.

The second item on the two-year frequency, the Applicant addressed that. They did discuss the flight inspection since September of '07. I've noted two of those inspections were per the NRC request, one in September of '08 during the aging management program review by the staff and then one in January of this year by the region, during the regional inspection.

Also, a follow-up question came up about exposure of electrical cables and direct buried cables to freeze/thaw resulting in an accelerated cable insulation aging mechanism. The staff did also do a review of that. Our electrical engineers requested the operating experience review group at Headquarters to do a search and were not able to come up with anything to that phenomenon.

And then the last item that we --

MEMBER RAY: Let's pause there for a second for two reasons. One, whoever is controlling the video, we need to get back to the slides that you're using if we can do that. At least these videos aren't --

MR. PLASSE: I'm sorry. It's Slide No. 10.

MEMBER RAY: Yes, thank you. Well, we'll use the hard copy until we can figure out why that isn't doing what it's supposed to do.

But the other point that interests me similar to what the Applicant said, there's basically an absence of information that's often not very satisfying. I'm sure if Member Powers were here who raised this issue, he would be not fully satisfied.

Is there any information about what's the design characteristics of the cable relative to thermal cycling? And I'm just groping for something here.

Mr. NGUYEN: My name is Duc Nguyen. I am

the reviewer of the electrical.

The question about thermal cycling, the design is -- typically design can handle up to, you know, three or four times of the rated voltage. So the total cycle is not a problem.

In addition, this cable energized all the time, especially from the off-site power, and this cable operates voltage, 13.8. But the rated voltage is two or three times. So total cycle is not a problem.

VICE CHAIRMAN ABDEL-KHALIK: Do we know anything about the glass transition temperature, for example, of the polymeric insulating material for these cables?

MR. NGUYEN: Can you repeat your question again, please?

VICE CHAIRMAN ABDEL-KHALIK: Do you know anything about characteristics of the polymeric material, for example, the glass transition temperature?

MR. NGUYEN: Maybe the Applicant can answer, but this is typical for EPR insulation cable, and what we've seen on site is even if it's submerged in water, some of the Applicants, they do the operability test. It's the proper test. The long terms of more cable is the issue, but at this site, since they replaced the cable in 2005, this is brand new cable, and we didn't see any water accumulation in the manhole.

We take the walk down, and this is very high elevation. We did that at the audit. We take a look, and this cable is very easy to access to, and we didn't find any problem with the water.

And keep in mind, the inspection frequency it is event driven. It's not the exact interval. If you have water, then the GALL. We require them to do more inspections. So it is even driven. So the two-year frequency is not the set interval.

MEMBER BROWN: This is Brian Holian.

We're not asking about the event frequency again. We're specifically asking about, you know, kind of is there any inherent data that we have on the strength of the cable, you know, for freeze/thaw, and I don't know if the staff has that information. If the Applicant has it, you're invited to comment. If not, the staff can try and get back to you on that issue.

We primarily looked at operating experience. I agree that in the absence of information that doesn't mean that we are not still concerned about the potential for an aging mechanism due to that. That's a similar issue we're going to go to research on also and see if we should be putting one-time inspections in place for this aspect. So that's in the future.

MEMBER ARMIJO: I'm surprised that we don't have a crisp answer to that freeze/thaw question. I would think that the cable manufacturers would address all of the environmental variables that affect the performance of their cables and the insulation, and so you know, we don't have a crisp answer.

MEMBER RAY: Sam, I think the best information was presented by applicability to distribution centers because they have got enormous --

MEMBER ARMIJO: It hasn't seemed to come up as a problem.

MEMBER RAY: -- an enormous application.

MEMBER ARMIJO: Somewhere along the line there's a reason it's not a problem, because somebody has put it in a spec and made the right kind of materials to take that kind of --

MEMBER RAY: They do.

MEMBER BROWN: Sam, the EPR materials typically acceleration age tested, and then they run a bunch of tests. You know, it's all based on the standard of Arrhenius stuff. I mean if you want to you can either believe it or not believe it, but that's what they do when they test it.

I also thought I heard you say that these cables were energized, and carrying current the whole time.

MEMBER ARMIJO: I was going to ask that. Could we put that on the --

MEMBER BROWN: Is that what you said? These cables are energized continuously so that they're drawing real power, real current?

I'm not as bad as I sound, Mike.

MR. NGUYEN: Maybe the Applicant can confirm that.

MR. RUETHER. Jose Ruether.

Yes. These cables, the medium voltage cables are 13-8, are energized all the time and do carry current.

MEMBER BROWN: Okay. Is it a half an amp or is -- I mean, I presume these are pretty heavy power cables relative.

MR. RUETHER: Typically during the summer time -- well I guess we're talking about when in operation -- they would be carried in one bus of safeguards, safety related equipment, which would include 40 volt loads that would be continuously running.

MEMBER BROWN: So there's a reasonable amount of current in the cables. I mean, once you have current running in them, they kind of stay heated, and you don't experience the same freeze/thaw phenomenon that you do as if they are de-energized and just sitting there. That's why I asked the question.

I mean, if it's not relevant.

MR. RUETHER: No, that's fine.

MEMBER MAYNARD: This may be an issue that is worth the staff doing some follow-up, but I don't see it anything being unique to Prairie Island. These cables are not really even unique to nuclear power. There's an awful lot of industry experience with cables like this that are exposed to freeze/thaw conditions and stuff. So I don't think there's any immediate safety issue and there's nothing specific about Prairie Island.

MEMBER ARMIJO: That was not my point, Otto. I Just thought that, you know, the operating experience tells the tale. You know, these things don't fail by that mechanism, and I just want to know the reason, and my guess is that people are taking that into consideration when they designed and specified the materials.

CHAIRMAN BONACA: I don't think it's specific to this plant. However, this issue is coming back again and again. We are raising questions. We don't get answers oftentimes, and yet there may be available answer to the questions we discussed specifically because the manufacturer probably does testing and determines whether the requirements does permit. It would be something that we should try to get some better answers in the future.

MEMBER BROWN: Yes. I didn't disagree with that. I was just trying to provide some perspective. We should not be answering these questions.

MEMBER RAY: It sounds like Brian has got a handle on it. We'll see what we see.

MR. PLASSE: Okay. The slide came back up. Before we get to that slide, I just want to make sure. I've covered everything I intended. Are there any other questions on any of these items or anything else that you have for the staff?

(No response.)

MR. PLASSE: In conclusion, as documented in the final SER from October 16th, the staff has concluded there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted, and that the current licensing basis at the requirements of 10 CFR 54.29 alpha have been met, and that's the staff's conclusion.

MEMBER RAY: Thank you.

I'm supposed to, I guess, invite any further discussion among the Committee members at this time. We'll obviously be taking this up in the context of a draft letter.

If not, it's one minute over, Mr. Chairman.

CHAIRMAN BONACA: All right. Thank you very much for the presentation, and if there are no further questions, we'll take a break. Get back at 10:15.

(Whereupon, the foregoing matter went off the record at 10:01 a.m. and went back on the record at 10:17 a.m.)

CHAIRMAN BONACA: We will get back into session.

And we have draft final Regulatory Guide 1.205, and Professor Apostolakis will take us through the presentation.

MEMBER APOSTOLAKIS: Thank you, Mr. Chairman.

We met with the staff for three Subcommittee meetings in June, August, and the last one was in November 13th, and we discussed draft Regulatory Guide 1.205 and the associated standard review plan. During these meetings we had many, many comments back and forth.

The staff has been very responsive to the questions of the Subcommittee. They made changes to the documents as appropriate, and without any further ado, I'll let them take over today and tell us what the status of the two documents is, and I believe they are requesting a letter. Even if they're not, there is one.

(Laughter.)

MEMBER APOSTOLAKIS: So who is -- Sunil?

MR. WEERAKKODY: Yes, sir. Thank you.

MEMBER APOSTOLAKIS: Okay.

MR. WEERAKKODY: My name is Sunil Weerakkody. I'm the Deputy Director of Fire Protection in NRR.

As George said, we are here today to present to you Reg. Guide 1.205, Revision 1, and the Standard Review Plan, and also talk about Standard

Review Plan Section 9.5.1.2 and request your endorsement to issue them.

Just for the benefit of a few of the new members here, to give a two-minute summary of the historical context. The Rule 805 or the risk informed alternative to deterministic fire protection was published in 2004. In 2005, we had two plants volunteering to pilot the effort. Duke Energy volunteered Oconee and Progress in Energy volunteered Harris.

In 2006, we issued -- again some members who are here today worked with them then -- we issued Revision 0 to Reg. Guide 1.205. It was trouble even at that time because Reg. Guide 1.205, you know, we were bringing I would say many of the technologies or subcultures, you know, fire protection and PRA together, and then we had some challenges with that.

And then in 2008, you know, two years after we published Rev. 0, we received the license amendment request from the two pilots. That was last year, mid-last year, and the staff has been working with the pilots as necessary to read those safety evaluation reports.

You know, with that background going into my first slide here, in 805 we have a comprehensive, coherent regulation that enables us to risk inform a major safety program at power plants, in this case fire protection. One of the things we found out, and this is kind of hindsight in some ways, that we really needed to go through the two pilots to understand the number of complexities that was beneath the surface.

There were a number of things that when we issued Rev. 0 of Reg. Guide 1.205 in 2006, we just did not have a good appreciation of simply because the reg. guide had not been piloted.

But you know, that stage is behind us. We are presenting here today to you the Revision 1 of reg. guide, and the staff believes that the Revision 1, which has benefitted from the lessons learned from the two pilots, is an improved and an additional guidance to facilitate compliance with the fire protection requirements of NRC for the licensees, and we believe that relatively Revision 1 provides a very clear and a consistent regulatory position with respect to Rev. 0, again, due to the benefit of the lessons learned from the pilot.

And one other thing we want to emphasize to the full Committee is it is fully vetted, meaning we have gone through a number of public meetings where we received and addressed stakeholder comments, you know, mostly the two pilots, a number of other plants who are (unintelligible), and George mentioned we had not one, not two, but three very should I say painful meetings or pleasurable meetings and received good feedback from the Subcommittee, and we incorporated a number of their comments.

What you have here, what we are presenting today, we have interoffice conference, OGC, Research, New Reactors, NRR. So we have an agency --

MEMBER APOSTOLAKIS: It was pleasant.

MR. WEERAKKODY: Pleasant. We have a very pleasant three meetings with the ACRS Subcommittee.

And you know, one final draft was, again, shared with the public in September and October, and then one final point that is not here, and we were very pleased at the Subcommittee. The two pilot plants who came in here, and both pilot plants mentioned to this Committee that in there also Revision 1 provides a clear framework that could enable a good, stable future licensing basis for plants through 805.

With that, let's go to my next slide. The objective here is to brief you, and we believe the guidance improves clarity and provides regulatory stability for both pilot plants and about 48 or about

40-plus non-pilots who are awaiting issuance of this reg. guide, and we believe that issuance of this reg. guide is going to contribute to the regulatory stability, and I am personally motivated to get an approved endorsement because my boss who sits there has my request for leave, and he's only going to sign it if I get this reg. guide out by the end of this year.

MEMBER CORRADINI: You said leave or vacation?

MR. WEERAKKODY: Vacation. It's a very earned vacation, but he's not going to sign it until he sees a letter from this Committee saying the reg. guide can be issued. So it is holiday season, you know, and --

(Laughter and simultaneous conversation.)

MEMBER BANERJEE: And what about the new plants? Is that like the 81,000 ESBWR or whatever? None of these have been --

MR. LAUR: The rule is not applicable.

MR. WEERAKKODY: So with that, Steve Laur has been our lead for this.

MEMBER APOSTOLAKIS: Wait a minute. Let's understand this issue about the new plants. IF I build a plant tomorrow, I can choose to go with NFPA

805, right?

MR. LAUR: No. There is a -- Harry will answer this.

MR. BARRETT: There is a Standard 806, which is designed to be used with the newer plants, and it gives the same risk informed ability to change the licensing basis as 805, but the plants are originally designed to 804, which is a deterministic standard, and they only use the risk informed tools once they get their license.

MR. LAIN: This is Paul Lain from the staff.

I'd also like to add that in the '90s there were a few SECYs that came out that actually made the fire protection requirements much more stringent for the new plants also. They want three-hour basically separation between the --

MEMBER APOSTOLAKIS: So what would be my baseline fire protection program for a plant I'm going to start building tomorrow?

PARTICIPANT: Eight, oh, four.

MR. LAIN: That would be NFPA 804, and then 806 would be utilized as a risk informed change process. And 806 is actually not published yet. It will be published probably spring of next --

MEMBER APOSTOLAKIS: I still have to change?

MR. LAIN: No, that's just if you need to make changes, I would think going forward as a process, but I think the new reactors are requiring fire PRAs.

MEMBER APOSTOLAKIS: Is that clear to everyone?

MEMBER BANERJEE: No.

PARTICIPANTS: No.

MR. KLEIN: My name is Alex Klein. I'm the Fire Protection Branch Chief in NRR.

Let me try and help clear this up if I can. Paul Lain is exactly correct in terms of there were a series of SECY papers that were sent out to the Commission. Those SECY papers contained guidance for licensees with respect to what fire protection requirements and guidance were expected of licensees who were building these new plants.

Those SECYs were, in turn, incorporated into Reg. Guide 1.189, which is our deterministic side of the fire protection guidance, if you will. Licensees who are building these new plants are following the guidance in Reg. Guide 1.189 and those SECYs that Paul alluded to.

Now, if a licensee or an applicant, if you will, in this case for these new reactors wishes to adopt a different approach, then they would have to propose that to the staff. There is nothing in Reg. Guide 1.189 right now that either endorses or mentions in any way Form NFPA 804 or NFPA 806, which is yet to be written.

So at some future date if a licensee wants to adopt a different approach to what they've taken under Reg. Guide 1.189 on the deterministic side, they would have to come in and see the staff because we have no rule right now that would provide that. So they would have to come in on an individual basis if they wish to take a risk-informed performance-based approach with their fire protection program moving forward.

Having said that, the SECYs recognize the lessons of Appendix R, and the plants realize that because now you're designing them basically from scratch from day one. They recognize the need to separate your redundant trains. So my personal view is that for licensees who are -- excuse me -- for vendors who are designing these new plants are incorporating these lessons learned from the Browns Ferry fire, from Appendix R days. So the need for a licensee to use a performance-based risk-informed approach in my view point is diminished because they have got it well separated.

MEMBER APOSTOLAKIS: I think we're getting off the subject here, but --

MR. KLEIN: We are, yes.

MEMBER APOSTOLAKIS: -- if I build a new reactor and I have a very detailed as much as I can fire PRA, I can't use that to guide me in the design of the plant?

MEMBER CORRADINI: The plant's design. Their point is --

MR. WEERAKKODY: They already have nowhere impact. I can give you a very specific example.

MEMBER APOSTOLAKIS: Yeah?

MR. WEERAKKODY: Before the NRR and NRO was split, we were in the ESBRW DCD, and there's a statement there that was somewhat loose in the sense that the word was something like they'll do separation when practical, and we went back and said, no, that's not how it should be written. The only areas in the plant where you can accept, you know, separating the two trends is containment and control room.

So I think what Alex said, and I fully support it, one of their policies, they have this inform the design.

MEMBER APOSTOLAKIS: But they cannot start with a goal for CDF from fire contributions and work backwards. Like a performance-based --

MR. WEERAKKODY: That is exactly correct, yes.

MEMBER APOSTOLAKIS: -- approach to seismic risk.

MR. WEERAKKODY: Yes, yes.

MEMBER APOSTOLAKIS: They cannot do it.

MR. WEERAKKODY: Yes, that's correct.

MEMBER APOSTOLAKIS: Okay.

MEMBER BLEY: You can do it, but you still have to --

MEMBER APOSTOLAKIS: No, you have to go out and get approval if you do it.

MR. WEERAKKODY: Yes.

MEMBER APOSTOLAKIS: All right. Let's --

MR. WEERAKKODY: Yeah. I just wanted to turn it over to Steve, and then Donnie Harrison is the Branch Chief of PRA Branch, and Harry Barrett is a senior fire protection engineer and also the lead project manager for the Harris license amendment request.

So Steve.

MR. LAUR: Okay. I'm going to address the standard review plan and Reg. Guide 1.205, and I just want to close out this other discussion. It's not a hole in our reg. guide. This regulation and the standard specifically are for existing plants. It's a bigger issue as Alex pointed out.

Okay. What I'd briefly like to cover is the framework of the SRP and the reg. guide. What is the motivation and the purpose of these revisions? In the case of the SRP, it's a brand new document.

The SRP itself, 9.5.1.2, which is an initial decimal compared to most of the SRPs, is consistent with the Reg. Guide 1.205, Revision 1, and then talk about the comments and how we resolve them for the reg. guide, and then a little bit about stakeholder interaction, and I include not only the public there, but also the ACRS Subcommittee, and I look at it as three times not being painful, but I mean, if you didn't like it, you wouldn't invite us back.

(Laughter.)

MR. LAUR: Maybe we are a little bit slow on some of the comments, but we finally got the message.

I'll then open it up for questions, but of course, as usual, you can ask questions at any time.

Okay. To start off with the standard review plan, because I don't want to talk about it much unless you want to, basically NUREG-0800, the standard review plan, has a number of chapters and sections, and the existing 9.5.1 is deterministic for the most part.

So what we basically did was change that to 9.5.1.1 and this new one is 9.5.1.2, which allows you to, if you have a fire protection program that complies with 10 CFR 5048 alpha and bravo, which is Appendix R, that's 9.5.1.1. If you want to do alpha and Charlie, which was the NFPA-05 risk-informed performance-based, you do 9.5.1.2, and that's the guidance for the staff how to review it.

We also have developed -- we're showing the slide off to the side -- an ER template that matches this content as well. That's still draft. It's what we're using to write the actual safety evaluations in the two final plans.

Next slide.

Basically, this is my last slide on this unless you have any questions. The format is a typical SRP format. It's consistent with the reg. guide, but the reg. guide has a whole lot more guidance to the licensee, one acceptable way of meeting our requirements, and this basically says make sure that the licensee has done that one acceptable way or they've justified any deviations.

One thing that is kind of unique that I think is worth just mentioning, but we have an attachment, and we might be the first one when this gets published to actually have this, but there's a new office instruction that talks about the seconds reviews. When you first get something, is it complete and sufficient for us to begin our review?

And we've actually included that in the SRP, a check list to say does it cover all the bases. So that it makes it clear to not only the reviewers, but the licensees who see this can make sure they have all of the elements covered.

Because of this being the mirror image and less detail than the reg. guide, I'm going to focus the presentation on the comment and resolution for the reg. guide, unless you have questions.

Okay. The framework for Revision 1 and the reg. guide in particular, 1.205, the industry developed a guidance document, NEI-0402, and the one we actually endorsed in our initial reg. guide was Revision 1 of that document. A year and a half ago, maybe two years ago, they came out with Revision 2 to that document, the drivers, but that is what we are endorsing in this revision to our reg. guide.

And so we put out Draft Guide 1218 I think it was February or March, I think, March of this year for public comment; received the public comments and resolved them; talked to the ACRS; had several more public meetings; and that's what Sunil was talking about when he says we think it's fully vetted.

We have heard and we have responded to the comments, all the comments, and we have incorporated them where possible.

Next slide,.

So why are we doing that? Well, one of the things we need, when you embark on a pilot process, you know it's a learning process, and we set up a frequently asked questions process as a way of formally documenting what are in effect interim staff positions, interim staff guidance, and so that there's some pedigree so the licensee and the pilots, in particular, have some confidence that it's not going to change on them.

A number of those have been closed in between the time of the initial industry guidance and the current industry guidance.

We also have had a number of what they call pilot meetings where we meet with the two pilot plants, see how they're doing, review detailed information that you wouldn't normally review in a typical license amendment because it's a pilot to make sure we understand, you know, the nuts and bolts of what they're doing.

We also conducted regulatory audits about the pilots earlier this year, January and February, I believe, and saw first hand what they were doing and had a modifier guidance.

So the bottom line is there have been a number of factors, including the culmination of these changes into NEI-0402, that is causing us to revise the reg. guide, and that was always foreseen, and in fact, there will be a Rev. 3 -- excuse me -- a Rev. 2 to our regulatory guide to incorporate the remaining frequently asked questions and other nuances as we learn more.

We don't expect those to be major. We believe we captured the majority of the issues.

Okay. Most of the changes were to clarify the guidance. In fact, one of the public comments very recently at one of our meetings was, you know, industry may not agree with going doing Path A instead of Path B, but they said whatever you do, make it clear which one you're saying is acceptable, and so we clarified the guidance.

In one major area there was missing guidance, and I have another slide following this one, additional risk of certain recovery actions, but the goal of all this is to foster full and scrutable compliance. That is to say we don't want what happened with Appendix R, where every time we turn around there's a special case that needs an exemption.

As most of you should be aware, this rule has built in provisions, performance-based aspects to eliminate the need for most exemptions you could think of.

Next slide.

So the additional guidance I was talking about, the version we endorsed with the original reg. guide of 0402 provided guidance that some previously approved recovery actions did not require a risk assessment. On a closer reading of this NFPA-805 standard, which is incorporated into the rule so that this is rule language, it turns out that's not consistent with the rule.

The original reg. guide was very -- kind of danced all around this issue -- it was very I don't want to say "clever" because that would do the issue -- but basically it did not address this. There was a hole in the guidance. So we've added the guidance. We correct this omission, and based on all the feedback, we believe we have a clear set of requirements for previously approved recovery actions.

MEMBER APOSTOLAKIS: Do you think that rule may be revised at some point in the future?

MR. WEERAKKODY: This is what we have right now.

MEMBER APOSTOLAKIS: I understand that.

MR. WEERAKKODY: Yes. We may have a revision coming, but what we're going to do is learn some more by (unintelligible).

MEMBER APOSTOLAKIS: Is it up to the staff to decide whether the proposed rule to revise the rule?

MR. LAUR: I think generally we would write a Commission paper.

MR. WEERAKKODY: We would make a proposal to the Commission, yes.

MEMBER APOSTOLAKIS: If there is a need.

MR. WEERAKKODY: Yes.

MR. LAUR: But about a year ago we were talking about this rule, is this a fundamental flaw in the rule, and I think if you go back to Sunil's first or second slide where he said this is a coherent, I think we have learned a lot. This was very well thought out. It's just that we were not careful. It's complicated. We are not careful in reading all of the various defined terms.

The rule probably does not need revision unless you fundamentally disagree with this previously approved recovery act.

MEMBER APOSTOLAKIS: Well, I mean, something that's previously approved, and then you come back and you reopen the issue. It seems to me it's not such a great idea. We have to live with that now, but I just don't think that's a way to regulate.

MR. LAUR: We may have heard that opinion on an other occasions.

MR. WEERAKKODY: WE are keeping that. That also, I think, what Mark has directed me to do is to let's keep learning from the two pilots as well as a couple of non-pilots, and at some point in time if we find that everyone could benefits with revision to the rule, we'll make that proposal to the Commission, and then the Commission, of course, has to go through it.

MR. LAUR: Next slide.

Okay. So the stakeholder comments. If you look through the documents that were sent to you, pretty voluminous, but what NEI did with their comments was pretty much repeat the entire reg. guide with comments wherever they have. So it was very comprehensive, and some of the other stakeholders did the same thing.

But they can be pretty much summarized into five major areas. There's several comments that had to do with fire PRA, and there are different flavors of that. I've got them on the slides.

Comments on cumulative risk; there were some comments on a sample license condition. The reg. guide has a sample license condition that we expect licensees to use most of. Some of them are plant specific like which modifications you need, but other parts are expected to be used as is.

Risk of previous recovery actions, there were comments on that, and then the definition of primary control station, which is kind of interwoven with the recovery actions, but it's easier to discuss it separately.

Okay. So fire PRA, the first major heading under fire PRA was methods, and the reason is NFPA-805 says that the methods you use have to be acceptable to the authority having jurisdiction, which is us. They want us to clarify what that meant.

We were think the method that they used to apply it. The industry was concerned we were going to expand that to mean the entire PRA, how you build a PRA.

So we have limited the discussion of the methods to the cause and effect relationship or anything else associated with how you apply the PRA. The other comments that don't limit the topical reports. What we really meant there was generic. We didn't mean topical reports per se. So that was easily to fix. So the way we respond to these, we were able to incorporate most of their comments.

As far as a cause and effect relationship, we explicitly state that they may make changes without us having to approve a method if it falls into one of these three categories. The first one is a method that was used in the peer reviewed baseline fire PRA.

The second was if we have approved the method, obviously they can use it.

And then the third one is we allow them to demonstrate that their method clearly bounds the risk impact.

The next area, the fire PRA had to do with the model itself. They said, well, the rule says the PRA model needs to match the as-built, as-operated and maintained plant, and they said, "Well, how often do we have to update it? Give us some guidance on model updates and upgrades, and also provide clear PRA submittal guidance. What do you need us to submit for you to approve this?"

I believe the original reg. guide was totally silent on this. What we tried to do in this version is to say we've already determined that. Outside of fire protection, we've already determined that risk informed applications, the PRA quality and the update and all of that stuff is Reg. Guide 1.200. That's it. They have submittal guidance in it. It has guidance for updating, et cetera, through endorsing the ASME/ANSI PRA standard.

They also had comments that had to do with what risk processes are required when you use the fire PRA, and in particular, the comments had to do with when does the plant change evaluation required; which recovery actions require a risk assessment -- all of that was previously approved -- and then we had said all recovery actions require a risk assessment, and they said, well, the rule doesn't really require that. It just requires ones that are the success path, the credited success path for meeting the performance criteria.

So we modified the reg. guide. We discussed explicitly change evaluations and fire risk evaluations, and by the way, that's one of the areas where these things sound the same, but they're different sections in the rule. They have different purposes, and we didn't realize that until we got into the pilot process.

We provide additional guidance on how to address the risk of previously approved recovery actions, and I'm going to talk about that in a separate section, and then we did limit the scope, basically put the rule language in there. It's not all recovery actions. It's recovery actions that meet the success path definition.

MEMBER APOSTOLAKIS: Well, again, I'd like to draw the attention of members who were not at the Subcommittee meetings and maybe get your views on that, Steve. We have received complaints of the industry that the fire PRAs are consuming tremendous amounts of resources, to the point where the industry doesn't feel that they have anything left to do anything else in the risk area.

And I'm wondering why that is. Is the

methodology evolving all the time or what is your view, Steve? Do you agree with that, first of all?

MR. LAUR: Specifically about resources, I believe what I've been told, yeah. I mean, we heard numbers of how many millions more it's cost.

MEMBER APOSTOLAKIS: Why is that so? I mean, what is --

MR. LAUR: My personal opinion is it's not methods. It's scope, and the scope, we view the fire PRA for both Harris and Oconee, and plus we went on these other audits to look at the overall process, and I don't remember from the November meeting when they gave their presentation. They were talking about thousands of scenarios. So unless previous studies like the IPEEE where you might assume a room burns up and then if that screens, you're done with that room. If it doesn't screen, you go down to the next level.

They look at each individual source, and if the source, if you can break it up into two heat release rates, so each source has two potential fires, one that may or may not impact the trays and one that may burn them up. Okay?

So for every source in the room, they've got two scenarios. Every room they've got multiple sources, and then they have to consider the spurious actuation issue, which borders on intractable. I mean, if you think of (unintelligible) explosion, I mean, permutations and combinations of wires, now, what at least one of the pilots did was they just assumed spurious could happen if it's in the tray somewhere and let the cutsets drive them to go look at the wiring.

So that's exhaustive, but it still ends up with large numbers of scenarios, large number of tables. They mention something in -- I can't remember -- their wiring, cable tray databases have tens of thousands or hundreds of -- tens of thousands of entries.

MEMBER APOSTOLAKIS: I don't understand why all of a sudden they're doing that. I mean, there have been fire PRAs in the past that didn't go through that. Did they find that these fire PRAs were not realistic? What is it that's driving this detail?

MR. LAUR: I believe it's the fire testing results that said hot shorts may not be non-critical. Now there were, as I recall anyway, there were assumptions in a lot of cases that certain types of hot shorts could not occur or were not likely.

MEMBER APOSTOLAKIS: That's also the source issue. They have the sources and --

MR. BARRETT: There are a couple of things driving that. I think one of them is that the NUREG-6850, which combined with --

MEMBER APOSTOLAKIS: -- efforts.

MR. BARRETT: Yeah, that was to be the state of the art and put everything in one spot so that everybody knew what the state of the art was.

That state of the art is basically starting with your ignition sources, counting them up, figuring out what the frequency is on an ignition source basis and then building essentially a mini PRA for each ignition source. That's the state of the art. So that's what they did.

MEMBER STETKAR: As kind of a practitioner who is even as we speak struggling with this issue, the problem with NFPA -- NUREG-6850 is that it was written by two sets of people. It was written by people who were fire modelers who loved to look at details of modeling fires, and it was written by people who were electrical circuit analysts who loved to look at details of electrical circuits. It was not written by a PRA practitioner.

The PRA practice was sort of put over it rather loosely. So what I've seen people doing, I think part of the reason that the industry is spending so much time is it is a huge problem, but you have these opposing levels of detail. One set of people, as you mentioned, Harry, is trying to look at setting large numbers of very, very small fires and modeling them.

Other people are doing, as we heard from the industry thousands of circuit analyses to look at individual wires in individual cables, in individual cable trays to determine electrically what would happen due to all possible combinations of short circuits and faults to ground and all of that sort of thing.

That's a huge amount of work. I think that the pilot programs, the experience form them will provide some insights about how to scope the analysis both in terms of what level of detail do you need to go into in the fire modeling, and what level of detail in the circuit analysis.

At the moment it's like 30 years ago in the risk assessment business when you asked someone to build a model of a reactor protection system. Somebody would go away for nine months because they believed that they needed to model every little wire connector and every little fault. We've learned a lot in order to be able to streamline that process more over 30 years, and I think fire risk assessment is now in that throes.

MEMBER APOSTOLAKIS: I understand that NUREG-6850 is under revision now. There is a new joint effort.

MR. LAUR: I think there's a supplement planned.

MR. BARRETT: Yes, there are several frequently asked questions that deal with 6850 methods, and both EPRI and RES are looking at looking at putting out a combined report that combines those and publishes this.

MEMBER APOSTOLAKIS: And maybe simplify it a little bit and avoid some of that?

MR. BARRETT: Well, I think what they're putting out is changes to the guidance where we found that there was reasonable things that you could do to either simplify or come up with easier methods.

MEMBER STETKAR: I don't get the sense that there's going to be much change in the guidance for how do you scope the problem. The sense that I get is there's no guidance in some of the details --

MEMBER APOSTOLAKIS: Well, that seems to be --

MEMBER STETKAR: MEMBER STETKAR: -- rates or guidance about how you do circuit analysis or something like that, but it tends to be more --

MEMBER APOSTOLAKIS: Is it scoping the issue though?

MEMBER STETKAR: I think it is. I think it's how do you address the problem most efficiently from a risk assessment potential, but I don't know how you write guidance for that, George. That's the problem

MEMBER APOSTOLAKIS: Okay.

MEMBER BLEY: You can do it, but you still have to --

MEMBER APOSTOLAKIS: No, you have to go out and get approval if you do it.

MR. WEERAKKODY: Yes.

MEMBER APOSTOLAKIS: All right. Let's --

MR. WEERAKKODY: Yeah. I just wanted to turn it over to Steve, and then Donnie Harrison is the Branch Chief of PRA Branch, and Harry Barrett is a senior fire protection engineer and also the lead project manager for the Harris license amendment request.

So Steve.

MEMBER BLEY: And we've got a problem here that's a little different than we had when we were doing the same thing with the PRA. We just had a few of these studies going. We had time to digest and think about them, and it takes time. Yeah, the guys who did the pilots weren't coming up with ideas how to simplify. It's going to be another group working on it who do that, but here we're trying to do these all in a hurry, trying to get that learning how to simplify.

MR. BARRETT: The pilots did try to end up using simplified methods. For instance, at Harris one thing they did was they used the zone of influence calculations to try to cut down the scope of the number of cables they had to look at and say reasonably is this fire actually going to damage all of the stuff in this room, and they went and they calculated a cone of fire damage right above the source and tried to make that a simplistic approach even though it's still hundreds of scenarios that they had to look at. They tried to use tools that made that a lot faster.

But it's still the tunnel work. It's still a lot of manipulating of data and handling of different, you know, scenarios.

MEMBER STETKAR: It's a lot of work, and unfortunately, the numbers drive the work. Back 20, 15 years ago even, we were using conditional probabilities for shorts that are on the order of a factor of seven to ten times lower than is currently supported by the test data.

Well, those numbers allowed you to screen out many fire scenarios because the risk from those fire scenarios were low enough that you didn't need to do any further refinements. Now we have test data that don't support the numbers that we were using ten to 15 years ago. So it's more difficult to screen out those same identical scenarios.

I think the same thing is true now in the fire modeling. People seem to believe that a lot of the heat release rates are too high, but we don't have enough actual fire data to confirm that fact. So we have now two competing concerns in terms of both fire modeling and electrical modeling that are driving numbers up and people don't like high numbers. So they're doing more work to refine the analyses to push the numbers down.

MEMBER BLEY: One thing that came up in the Subcommittee, and this is the thing that really helped doing some of the complicated stuff and the rest of PRA, I think it was one of the pilot folks that said some of the difficulty they have is a lot of this -- and it's new -- is manual work that perhaps could get automated, and if that happens that may reduce this lot, but again, that takes time and a program, and it won't be there in six months or a year. It will happen eventually when people are struggling with how to do this more efficiently.

MR. LAUR: Not to belabor it, but there's one other point that I've noticed anyway since you asked. I think the utilities or licensees are worried. This is a rule where as before even if it's a 50.54(f) generic letter for IPEEEs, for example, they realize this is the first major licensing application where this fire PRA is not only going to inform things, but it's going to allow the inspectors potentially to look at the fire PRA.

And so what we saw in a couple of our audits was a reluctance even though NUREG 6850 says you can refine the analysis, and even though a good PRA or even fire modeling analysts would normally make some reasonable assumptions and say, well, this case, this doesn't make sense. The geometry is such that, the thinness or whatever; we found a reluctance to do that because they were worried that this guidance was somehow cast in concrete, and therefore, you will look at every hot short. You will look at the heat release rates that are in that book

Reg. Guide 1.205 and I think that's key, George, is the enforcement and the deadlines. It just forces you into this kind of brute force, no holds barred kind of approach, as well as the numbers that John mentioned becoming more probable.

MEMBER APOSTOLAKIS: I'm wondering though if these licensees had a detailed determined events PRA upon which they're building the fire PRA or by doing the fire PRA they find there are holes in their internal event baseline PRA so they're improving that, too.

So it's not all fire related in other words. IT's not clear to me.

MR. HARRISON: This is maybe a small element with the internal events, but I would say it's small, where plants are proposing modifications to take credit in 805, and, therefore, they have to reflect that modification in their internal events PRA as well, and I think Harris said that one of the great benefits was the alternate reactor coolant pump sill injection, and that benefit was predominantly in the internal events realm.

So they had a model from there, incorporate that model, and then use it in a fire PRA as well. So there's some of that that happens, but the majority is the fire issue, the multiple spurious operations, the fire modeling. That's really where the majority of the work is.

MR. LAUR: There was one case, one of the pilots when we did our review that there was a simplification in the internal events that was falling for internal events, but was erroneous if you did the file, and they had to go model some additional detail, but I agree it was minor. Both of these plans had already had relatively mature internal events models, had been through peer review, had addressed or were rapidly trying to address all of their facts and observations from the peer reviews of those.

This money you're talking about is the fire PRA.

MR. BARRETT: I'd like to add one thing. In Oconee's case, much of the cable routing that they did was also beneficial from high energy line break and tornado perspective, and I believe that's how informed their PRA results for those events as well because prior to working on the Appendix R. upgrade, they didn't know where a lot of the cables were, and so they went and traced those cables and looked at which trays got damaged by high energy line breaks, and they actually were able to hone in on exactly what got damaged, and that ended up helping them get a much higher understanding for both tornadoes and for high energy line breaks exactly what w as happening as far as that goes.

So I think it has gone both ways. I think it has helped a lot in the recent Oconee's case that they went and found those cables, but that's more of a cable issue than it is a PRA level of detail, but of course, they can use that in the PRA to really look at what specific damage has happened.

MEMBER BLEY: Of course there was one other thing that came up and maybe it's related to what you just said, Harry. I think it was Oconee, but one of the two showed what they spent and what they got back, and they gained a lot from doing this. I mean, it was areal payoff for them.

Now, not everybody would have that. So a lot of people were doing work.

MR. BARRETT: Actually both had that.

MEMBER BLEY: Did they both have it? I couldn't remember.

MR. BARRETT: Harris gained a whole bunch of risk decrease for the alternate seal injection, and the PSW mod for Oconee is making huge benefits for turbine early fires, tornadoes, and other issues.

MEMBER APOSTOLAKIS: One last thing. At the high level, do you think that it is worth it spending all of these resources on fire risk at the expense of other risk-informed initiatives? Is this really the most important issue we're facing?

MR. WEERAKKODY: I can share with you, George, one of the statements that the executives had with me. He said when he thought of going into 805, he also considered the longer term investment in benefits. You know, if he sees his asset as something that could operate for another 40 years, maybe another 60 years, and there could be other issues emerging, such as, you know, aging of cables.

So even though he is doing his part PRA and placing cables to look at this regulation, he sees other future benefits, and that drove him to support.

MEMBER APOSTOLAKIS: So you're saying it's okay

MR. WEERAKKODY: I'm saying it's just one exhibit. Others might say different.

MR. HARRISON: And I would add that doing the fire PRA is going to enable other risk-informed applications where the fire PRA would be beneficial, in particular, Tech Spec Initiative 4(b), which is the risk management tech specs, needs a fire PRA to be able to do that application. So the work they do here will pay off in other applications.

MEMBER APOSTOLAKIS: But it's almost like it becomes part of the baseline PRA. Now that we have the detail we need to do other things.

MR. HARRISON: Right. Now, we can do the other applications.

MEMBER APOSTOLAKIS: Let's move on, but, John, did you want to say something?

MEMBER STETKAR: Just quickly, I'll come back to the numbers issue. I think, again, in terms of level of effort, a lot of the effort that people are spending is in a desire to try to quantify precisely how small the fire risk is. That's a very, very difficult process.

Unfortunately, when people talk about risk assessment these days, they want to put every single number on the same footing and say, well, I have a sequence from a fire that's 1.234 E to the minus 8th, and I have something from internal events that's something different. That's a lot of work if you want to try to quantify precisely how small the fire risk is.

I think must less effort and much more

benefit comes from a less detailed fire risk assessment to identify areas of vulnerability. You don't need to do a very detailed fire risk assessment to show that there's a benefit from installing an alternate seal injection path. You don't need to analyze thousands of circuits. You don't need to analyze hundreds of different fire ignition sources within a given room You only need to do that if you want to try to quantify precisely how small the numbers really are.

So I think in terms of your question about is fire risk assessment beneficial, I think that you probably obtained 90 percent of the real risk benefit by doing a relatively small amount of the work. However, if you are then required for whatever reason to quantify precisely how small that fire risk is in comparison with all other sources of risk, that's where a huge amount of effort is.

CHAIRMAN BONACA: Then you come up with very large numbers for fire contribution.

MEMBER STETKAR: If you compare that fire contribution to the other contributions, that's right. That's the problem. That's the problem

MEMBER APOSTOLAKIS: But eventually you will want to have some estimate of what the contribution is. It may be in terms of taking care of vulnerabilities you can do.

MEMBER STETKAR: Well, when you ask in terms of are we spending effort, you know, that's an agency --

MEMBER APOSTOLAKIS: -- because you know, you hear all of the resources are going to fire and what is this and, you know, we can't do anything else. You know, we have to pay some attention to that.

Anyway, let's come back to the regulatory guide. Maybe, Steve, you can accelerate a little bit.

MR. LAUR: Okay. The comments said that you have no basis for tracking cumulative risk, and to do not evaluate them. We should not use Reg. Guide 1.174 evaluating the total change in risk associated with 805, and we did not appropriate these comments because there was clearly a paragraph in here that says you have to consider the impact on cumulative risk from changes, and the Reg. Guide 1.174 guidelines are appropriate, not to dwell on this, but it is true, and industry keeps saying this, that Reg. Guide 1.174 did not anticipate this rule, but the converse is not true. This rule has in the appendix 1.174, it has a regulatory analysis for the rulemaking, 1.174, and that's how we do business.

There are already appropriate thresholds that are reasonably small changes, and so we're using it.

A sample license condition, the way we word it, the industry was concerned it would preclude self-approval during the period that when we grant this license amendment until they're fully implemented, and usually what that is is one or two or more modifications that are part of the license condition to be fully compliant during that time they have to maintain their compensatory measures. They want to go make changes.

Well, we were not intending to preclude certain changes. We just didn't want them doing the PRA, the fire PRA changes until the PRA matched plant. So we have changed it to allow self-approval of certain changes during that transition period.

Okay. Previously approved recovery actions. The public comment was that if it was previously approved, it should be deemed to meet the deterministic requirements of the standard, and we did not incorporate this comment because contrary to the requirements of 805 where it specifically calls out the reactions does not meet the deterministic requirements.

And so what we basically say if it's previously approved, you still have to do the delta CDF and delta LERF because that's clearly in the regulation. However, the acceptance criteria we apply if it was previously approved is the previous approval. So we say you do not have to change that unless, of course, this delta risk is so high that it triggers either the cost of official backfit for an adequate protection concern.

MEMBER STETKAR: Steve, for the benefit of the other members who haven't sat through the three previous meetings of the Subcommittee, and to make sure that I understand this slide, at the current revision of the reg. guide, when I transition to NFP-805, I must quantify the fire risk including those previously approved recovery actions; is that correct?

In other words I must --

MR. LAUR: Above zero or are you talking about what we have written out?

MEMBER STETKAR: Currently, right now, Rev. 1.

MR. LAUR: Rev. 1.

MEMBER STETKAR: The current version of Rev. 1, what we are writing the letter on today.

When I transition, if I make the decision to transition to NFPA-805, I must quantify let me call it a baseline risk of my plant from fires, and that baseline risk must quantify the contribution from previously approved recovery actions; is that correct?

MR. LAUR: From a practical standpoint that's what everybody is doing, but as we discussed in the Subcommittee meeting, a licensee could theoretically apply deterministically with this rule and never have even a fire PRA.

MEMBER STETKAR: I'm talking about doing the fire. In a particular location, if I'm going to use the risk informed approach.

MR. LAUR: But the performance-based approach in here has to do with the additional risk, the delta risk of your proposed alternative to the term risk requirements.

MEMBER STETKAR: Yes. Now, let's say I quantify that, and if the differential risk compared to a perfect plant, a plant that complies fully with the deterministic requirements, if that differential risk right now exceeds the guidance in Reg. Guide 1.174, I am still okay for that location; is that correct, because --

MR. LAUR: For previously approved? Yes.

MEMBER STETKAR: Because it's a previously approved action.

MR. LAUR: Yes.

MEMBER STETKAR: But now I'm on record. I know what that differential is, and I cannot take credit for any other recovery actions in that particular area that would further increase the risk; is that right?

MR. LAUR: Right.

MEMBER STETKAR: Okay.

MR. LAUR: What we're saying is that you have already used up your margins.

MEMBER STETKAR: And even --

MR. LAUR: Beyond.

MEMBER STETKAR: You could have even more than used up your margin from a Reg. Guide 1.174 perspective, except that it's a previously approved action, and the new baseline risk now going forward, when I look at future risk informed applications, changes to the fire protection program, that new risk value becomes my new baseline risk.

MR. LAUR: You can basically start over, yes.

MEMBER STETKAR: You start over. You re-initialize things.

MR. LAUR: We find this license change to be acceptable, and then you start over.

MEMBER APOSTOLAKIS: But then you can make more changes that will be evaluated now with respect to the new--

MEMBER STETKAR: To the new baseline. You just re-baseline your core damage frequency, your risk.

MR. LAUR: Actually applying to the current plan.

Okay. Well, that covers my last bullet on this slide. So I guess unless you have questions.

Okay. The primary control station -- it's a little cryptic. So let me see if I could paraphrase the rule. Recovery actions is a defined term in this standard, and if a recovery action, they are actions taken outside the main control room or outside the primary control station or stations that are necessary to achieve the nuclear safety performance criteria, which are defined in her, including repairs and replacement or something like that.

Anyway, it's a nice definition, but this idea of primary control station, that's not defined, and depending on how you define it, you can as some of the members pointed out during the Subcommittee, if you define it not carefully, you could come up with some very ridiculous sounding things where you'd say you have to do the risk for this, but not for that even though it makes no sense.

So we have proposed a definition of primary control station in a draft guide, and we've revised it based on not only public comments, but also on the ACRS Subcommittee discussion. And so we have clarified it, and we have another slide that covers this.

Basically if you consider the main control room, that's pretty obvious what that is. But when I say primary control station, what we're saying is if you shift command and control from the main control room to either a dedicated shutdown panel or panels or an alternative shutdown panel, and those two are defined in Appendix R. We're saying these are previously reviewed and approved by NRC. Then if it's a dedicated shutdown strategy, those actions do not count as recovery actions.

Basically what you're saying is you have two control schemes and if the fire happens to affect the main one, you can go to this abbreviated scheme to shut down.

If it's the alternative shutdown, because those are not dedicated, we have some further criteria in the reg. guide that if that becomes a permanent command and control, more than one piece of equipment, the adequate communications control indication, et cetera, then we can consider that to be a primary control station and, therefore, it's not a recovery action.

Just as an aside, the reason, in my opinion, the reason this caused so much angst among the licensees was that in the Appendix R world you had this 3G3 option that allows you to handle things like control rooms where all of the cables are and you have to evacuate or do something else, and this standard does not address it that way. We thought that was another part where the rule was not optimal, but after thinking about it if you define primary control station in this way, you're basically saying you do have an alternative, and it's allowed under here by defining permanent control station that way.

MEMBER APOSTOLAKIS: So I just want to understand that. Let's say command and control is with the main control room. Then the reason they want to do something using the dedicated shutdown path, just a specific thing, then that is considered the recovery actions.

MR. LAUR: Yes, because the main --

MEMBER APOSTOLAKIS: The main control is.

MR. LAUR: And that little nuance actually came up in one of our stakeholder meetings where the industry said you're still ambiguous before we change it to this.

MEMBER APOSTOLAKIS: Yeah.

MR. LAUR: And obviously they would prefer something that was a little more lenient, but the comment was whichever one you pick, you need to make it clear what you're saying.

MEMBER APOSTOLAKIS: Now, this rule and the regulatory guide refers to previously approved recovery actions. So this definition of recovery actions was in place also, but the understanding was that this is a recovery action five years ago when a particular action was approved, or is it a new definition?

MR. BARRETT: It's a new definition because the old definition would have called it an operator action, operator manual action.

MEMBER APOSTOLAKIS: And that's all.

MR. BARRETT: That's a different phraseology. This is RAO-5 phraseology.

MR. LAUR: There are actually slightly different -- yeah, there are different rules.

MR. BARRETT: Different rules, definitions for Appendix R.

MEMBER APOSTOLAKIS: An what does that mean? I mean, they were approved. Is it possible, in other words, to have an action that is not considered a recovery action now, but it was considered before and vice versa?

MR. HARRISON: Yes. It would have been an OMA.

MEMBER APOSTOLAKIS: What do you do? You just go with a new definition.

MR. HARRISON: Yes.

MR. LAUR: Yes. A perfect example, and what I think this rule was trying to do --

MEMBER APOSTOLAKIS: You really like that. You keep raising it.

(Laughter.)

MR. LAUR: I lost my train of thought.

An example where recovery action might -- well, if you use an operator action of some sort to compensate for barriers, separations, suppression and detection, there are existing rules, not this rule -- correct me if I'm wrong here -- but that requires an exemption, and one of the two things from my perspective that has caused people to want to shift over to 805, there's two issues. One is the spurious, but the other one is unapproved operator manual actions that people thought, well, you approved the exemption over here. This is the same thin, and they weren't the same thing.

It requires an exemption. What this rule says is you don't need an exemption. Just tell us that the risk is sufficiently small and acceptable to the NRC. That's where this separation barrier, suppression and detection.

The control and abandonment thing is a little trickier, and that's why we had to come up with this definition. So a plant could easily have something that they would have to request, wasn't approved; they would have to request an exemption in their Appendix R, and all they have to do is give us a delta risk. We evaluate it and conclude that it's okay.

MEMBER APOSTOLAKIS: I sometimes get the impression that a lot of these problems are of our own doing. Life would have been much simpler, it seems to me.

MR. LAUR: That's a global "our." Possibly.

MEMBER APOSTOLAKIS: A global "our," yes.

MEMBER RAY: Well, the problem, George, is you have to live in compliance space like a few of us have done in our lives to realize that all of these things that they're talking about become really, really important.

MEMBER APOSTOLAKIS: I understand. I understand.

MEMBER RAY: Most of the stuff we talk about here nobody is going to hammer you over the head if you take a different interpretation or something because we're not talking about something that's going to be enforced the way this is.

MEMBER APOSTOLAKIS: The root cause of the problem is NFPA 805.

(Laughter.)

MEMBER RAY: The root cause of the problem is applying rules on something that already exists that wasn't designed --

MEMBER APOSTOLAKIS: Well, not the little paragraph that says do this risk evaluation for recovery actions, should never have been approved, but.

MR. LAUR: Well, to expand the definition of "our," this is an industry consensus standard.

(Laughter.)

MEMBER APOSTOLAKIS: We have been impressed by those over the years.

MEMBER STETKAR: Steve, just to make sure that I understand the recovery action, I've got it if I need to abandon the control room. We've even brought up the picture there.

If I have a fire in a -- let's say it's an I&C cabinet room where I lose not all but some controls from the control room. Let's say it's, you know, one half of one division because of the specific cabinets that are involved. And I decide to go to the alternate shutdown panel to operate the equipment from that division, but the remaining equipment is still operable in the control room.

Is that action now a recovery action?

MR. LAUR: Yes.

MEMBER STETKAR: It is. Thank you.

MR. LAUR: And in fact, I think -- yes.

MEMBER STETKAR: Thank you.

(Laughter.)

MEMBER STETKAR: Yes is good enough. It was emphatic. It was crisp. Thank you.

MEMBER CORRADINI: Let's move on. I am George for a short time.

MR. LAUR: Okay. On a similar slide,

there is a bullet. I don't think he read it verbatim, but there was one that said we had a lot of public meetings. We actually had a public meeting back a little over a year ago to basically say, hey, we've noticed some things about this reg. guide, and we put out some things about common control station. It doesn't look like a definition today. We put out things about the standard license condition needed to change and things like that.

So we've had a number of public meetings, and then after one of our ACRS encounters, we had two specifically to share the latest and greatest version with the public and actually found out some additional things where we weren't 100 percent clear.

The thing is from our perspective is we incorporated the vast majority of the comments. If something was, you know, one way or the other way and it had nothing to do with public safety, adequate protection, or the rule language, we went with the industry's suggestion.

The remaining hard spots are required by regulation, and therefore, it's necessary to have that guidance to foster the stability and the clarity. The industry said they still have some unresolved concerns. So I didn't want to be, you know, too onesided here. They said, well, the guidance is still not fully vetted. We now have this new understanding with what fire risk evaluations means, but we haven't piloted it.

Now, I think you heard at the Subcommittee meeting that they started, and it turned out that it's virtually the same risk assessment they were doing before, maybe on a different set of items.

The same thing with the recovery actions. We say, yes, you can limit it to just the success pathways. Well, that bring up a whole new issue. What's a success path? Okay. Well, that needs to be determined. Industry is going to start working on that guidance. There will probably be a fact that will end up being in the next revision.

But it's a big concept, but it's not major changes in the reg. guide. The reg. guide doesn't need a change as a result of that. And then after you transition to 805, from then on you're doing what's called plant change evaluation, and they said, "Well, we don't underhand. You don't focus on that very much. You just focus on this other thing."

Now, the answer to that is very simple. They have enough guidance in there. We have additional guidance. We endorsed it, but there was a little bit of angst there as well.

And then at the last meeting on November 13th, both pilots presented I guess for an hour a piece. At the end they said you should issue this reg. guide, and it was also said by some of the members at one of the public meetings we had before that that even though the industry doesn't agree with everything that we are doing, they understand why we're doing it. They understand the compliance issues, and they really need the stability that issuing this will give them.

MEMBER APOSTOLAKIS: That's temporary stability, I assume.

MR. LAUR: They like stability.

MEMBER APOSTOLAKIS: The results of some of these other issues.

MR. LAUR: And the FAQ process is still alive and well, and I can say that we always thought we'd do another revision, but I don't think it's going to be something we're adding guidance, you know, fix holes. I don't think that's going to happen again.

We also had -- I don't need to go to this slide. We were already talking.

We added a flow chart as a result of the members' comments. We fixed the primary control station, I think, finally, and there was a number of other changes that I didn't enumerate here, but that resulted in the discussion. There was good opportunity to flesh out some things. You get kind of in a group think mode when you're all in the same --

MEMBER APOSTOLAKIS: I think it's fair to say that you gentlemen did not disagree with us on anything; that you fought not to do something, correct?

MR. LAUR: That we did not disagree with you or did?

MEMBER APOSTOLAKIS: You did not disagree with us.

MR. LAUR: Yeah, I think that would be safe to say.

MEMBER APOSTOLAKIS: That's fair. No, I mean, this is details.

MR. LAUR: Open for questions at any time now.

Just to reiterate, we've incorporated significant lessons learned from the pilots, which as you know is the purpose of the pilot, and I think it has been alluded to in a couple of the conversations. We really -- I don't want to say we have the cart before the horse, but we are kind of doing some things in parallel that if you had enough time, if you didn't have the enforcement, discretion issues and everything, you would fully vet this through a pilot process before you finalized the guidance.

But we're learning, and you know, we're still trying to get it done.

We need to provide clear and consistent guidance. AS I mentioned the compliance issues and the stability, and fully consider the takeover comments, including the public, the industry and the ACRS.

So we'd like to request that we get the endorsement so that we can publish this, and not that it matters to me, but I would like to see him go on his vacation.

MEMBER STETKAR: Steve, one small question. It has been a little pet topic of mine in the background, and I thought, you know, in our November meeting you said you were going to consider revising a bit Section C.3.3 of the reg. guide, and that is at the moment Rev. 1 of Reg. Guide 1.205 fully endorses NEI-0001, Revision 1 for circuit analysis methods, and just for the record, NEI has updated NEI-0001 to Revision 2, and in particular the methods of treatment of multiple spurious actuations have been updated substantially from Rev. 1.

And, indeed, Reg. Guide 1.189 endorses NEI-0001 Rev. 2 methods. I thought in our November meeting you said you were going to go back and consider clarifying the endorsement in Reg. Guide 1.205 to limit the endorsement to only Section 3, I think it is --

MR. LAUR: Yes.

MEMBER STETKAR: -- of NEI-0001, which is the basic circuit analysis, but not endorse Section 4 and whatever the appendices are.

MR. LAUR: And, in fact, we went ahead and made preliminary changes which they shared with staff and I thought they shared with --

MEMBER STETKAR: I haven't seen those.

PARTICIPANT: I haven't seen it either.

MR. LAUR: Okay.

MEMBER STETKAR: The only version that I have is the same version that we saw in November.

MR. LAUR: What we did, there were five or six suggested changes that we could make. Okay. One of those was substantive, non-editorial, and we talked to OGC, and they said, "No, if you want to put this thing out for comment again, go through the whole process." And so we didn't do that.

But as far as changing the revision, we now reference or will reference before we publish this; we will reference Rev. 2 of 1.189, but the only place we reference that is for --

MEMBER STETKAR: NEI-0001.

MR. LAUR: And Rev. 2 of the meltdown, and the only place we reference 1.189 in here is for an example of a good --

MEMBER STETKAR: The deterministic stuff. Yeah, yeah. Okay.

MR. LAUR: So we change the reference to that, and I think you mentioned that at the other meeting before.

MEMBER STETKAR: That might have been.

MR. LAUR: And then we reference Chapter 3 of Revision 2 of NEI-0001.

MEMBER STETKAR: Chapter 3 of Revision -- it doesn't make any difference. It's Chapter 3.

MR. LAUR: We did that. There's another place where there's a very complicated sentence which we clarified slightly, but, no, these --

MEMBER STETKAR: I've just been handed the words. Thank you.

MR. LAUR: These words are editorial in our opinion, minor editorial changes. They add clarity, but they're not substantive.

MEMBER STETKAR: They add clarity and they bring everything into consistency between the two reg. guides, which I think is important, and it clarifies what part of NEI-0001 is actually being endorsed. And this is good. Thanks.

MR. LAUR: I have the questions slide. I'm just waiting to see if you have any questions.

MEMBER APOSTOLAKIS: Had enough? Are there any questions or comments from the members?

I'm really disturbed by all of this, not what you're doing, but what is happening, you know , out there. The methodology seems to be in flux all the time. Like what would happen, say, if three years down the line we revise the rule? We take out all of these references to recovery actions. Is that another revolution that will upset everybody?

MR. HARRISON: I think philosophically what that would do is those plants that have already been approved would gain flexibility to have the option to go back in. At that point they have a licensing basis they can live with.

MEMBER APOSTOLAKIS: Yeah.

MR. HARRISON: And if you remove things, then they would gain flexibility.

MEMBER APOSTOLAKIS: The other thing, Donnie, is that, you know, we had Subcommittee meetings and meetings where we have people there where you're sitting praising NUREG-5860, that this is, you know, the best thing after sliced bread, and now we have, you know, all of these problems and EPRI, when they were here, blasted it as if it was just the NRC that did it. You know, where does that leave us?

And then they would say, well, gee, the industry really is exhausting its resources, doing fire PRAs. The whole thing, I think, needs to be rethought, and you gentlemen will probably have some input to that because this situation is very, very undesirable in my view. To do all of these things, change the methodology; one day we have a great NUREG; the next day it's not.

Anyway, I guess, Mr. Chairman, we have reached the end of this section.

CHAIRMAN BONACA: You were fast.

MEMBER APOSTOLAKIS: We finished 42 minutes early I would like the record to show. Back to you, Mr. Chairman.

CHAIRMAN BONACA: First of all, let's thank you for the presentation, and second, we have a lot of time. As you know, at 12:30 we have this ribbon cutting ceremony with the Chairman coming down, and so we have time for that.

The only thing I could advise and do now in my judgment would be the Subcommittee reports.

PARTICIPANTS: We can go to lunch.

MEMBER APOSTOLAKIS: Ribbon cutting ceremony at 12:30. We can go to lunch.

PARTICIPANT: I mean, we will have cake for the ribbon cutting ceremony.

MEMBER APOSTOLAKIS: Or we can do what you say.

CHAIRMAN BONACA: Let's break now. I was told that the --

MEMBER APOSTOLAKIS: If you want to do that portion of the advanced, right?

MR. HACKETT: Yeah, I think that's correct.

MEMBER APOSTOLAKIS: Mario, if you want to do that, I can go over the Safety Culture Subcommittee in five minutes.

CHAIRMAN BONACA: The trouble is that is on the agenda.

MEMBER APOSTOLAKIS: Let's go to lunch.

CHAIRMAN BONACA: Let's take a break and get back at 1:15.

(Whereupon, at 11:33 a.m., the meeting was recessed for lunch, to reconvene at 1:15 p.m.)

AFTERNOON SESSION

(1:14 p.m.)

CHAIRMAN BONACA: Let's go back into session.

The next item on the agenda is long-term cooling, core cooling approach for the economic simplified boiling water reactor design, and Michael Corradini will take us through his presentation.

MEMBER CORRADINI: Okay. Thank you, Mr. Chairman.

So for the members, let me take a minute to do a little bit of catch-up before I turn it over to the staff. So as you all are aware, we've had a large amount of activity reviewing the chapters, the draft. I shouldn't say the draft chapters. The SERs with open items. We've concluded that issued interim letters.

In a separate SRM from the Commission, dated May 8th, 2008, the Commission stated that the ACRS should advise the staff and Commission on the adequacy of design basis long-term core cooling approach for each new reactor design based on its review of the design certification. So that has been a standing thing that we thought would be a good time to begin here with ESBWR since we're coming into the hopefully end phase of the SERs with open items. And it is actually timely, and we chose this time to do it because two weeks ago we had a Subcommittee meeting with the group that is our ESBWR Subcommittee where we looked again at essentially long-term cooling, and I guess I define it at least easily as days, defined anywhere from a few days to 30 days of cooling, and we looked at the Applicant's calculations using TRACG, as well as the audit calculations done by staff.

And I thought this would be a good time to get together to look at these and have the staff present their view of where we are.

We are not going to get a letter out of this today because there are still some issues staff is reviewing relative to the applicant. For example, vacuum breaker, performance, et cetera, et cetera. So at this point I would view this as a progress presentation to the full Committee, but the focus is to answer the SRM from the Commission.

So with that I'll turn it over to John McKirgan.

MR. McKIRGAN: Thank you. Thank you.

I'm John McKirgan. I'm Chief of the Containment Systems Ventilation Branch II for NRO, and let me introduce my staff there. Hanry Wagage is the lead reviewer for this activity, and let me just for the sake of time, I'll just turn it over to Henry and we can get started.

MR. WAGAGE: Hi. My name is Hanry Wagage. I'm from Containment and Ventilation Branch of NRO.

We are here today to present design basis, ESBWR containment long-term pressurization analysis. I'll be presenting regulatory tied data applicable to containment long-term cooling.

Allen Notafrancesco from the Office of Regulatory Research will be presenting staff MELCOR containment analysis.

Hossein Esmaili, also from Office of Technical Research, is an analyst, and he will be available to answer questions.

The Office of Regulatory Research with Sandia National Laboratory through a contract for analysis. Jack Tills, who is a consultant to Sandia National Laboratory, supported this analysis. Jack could be available during the presentation to answer any questions through a phone line of needed.

Slide 2.

This is the project team and technical teach

Next slide.

These are the criteria for containment long-term cooling. 10 cfr 50.46(b)(5) is on long-term cooling of the reactor core after an accident. When cooling the core, energy is transferred from the core to the containment. Therefore, the continuity of cooling the core and it has be transferred from the containment. As such containment cooling is required to meet 10 CFR 50.46(b)(5).

GDC-38 on containment needs to be more space. A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly consistent with the function of other associated systems. The containment pressure and temperature following a loss of cooling accident and maintain them at acceptably low levels.

Staff looked at these two regular criteria for this analysis.

ESBWR created the following systems to mitigate containment pressurizes and after LOCA. During the initial blow-down phase of an accident, steam is released to the suppression pool when (unintelligible). The -- cooling system condenses steam by heating and boiling water in the PCC tanks, which are located outside the containment.

Thus PCC redirects an area from containment to the outside. PCC does not need any operator actions or outside power to operate for three days following the LOCA. After three days, active intervention systems start, where the systems are PCC tank refill and PCC vent fans.

In addition, analysts credit passive autocatalytic recombiner systems after three days to remove any radiolyses (phonetic), gases which are hydrogen and oxygen produced in the core.

In determining acceptable containment pressure and -- the long term to meet GDC-38, the staff used Commission's guidance in SRM to SECY 94-084. In SECY 94-084, staff proposed to the Commission that for passive plants, safe shutdown conditions for reactor should be acceptable as stable shutdown conditions. The Commission accepted the staff's recommendations.

The staff used GE-Hitachi's Type G containment analysis and staff's MELCOR analysis to determine ESBWR compliance with GDC-38. ESBWR compliance with GDC-38 is pending upon resolution of RAI 62.140, which is on long-term containment cooling.

This shows G --

MEMBER CORRADINI: Can I just interject

and make sure everybody understands where we sit? So where we sit is that the Applicant has submitted to staff and they're reviewing a supplement, a final supplement on these calculations where they were asked to do a series of calculations with four fans, six fans, three days, 30 days and a range of conditions.

Staff has it. They're still under review, and this is kind of an interim on some of the results we've seen from them and from the staff's audit.

MR. WAGAGE: Thank you.

This curve shows containment pressure prediction as presented in the DCD Revision 6. We have an open item, open RAI on the containment pressurization analysis and the final figure may be different.

I'm using this to illustrate how staff is going to determine the plant's compliance with GDC-38. We'll be talking later about how this compares with staff's MELCOR containment analysis.

ESBWR mitigates the accident with completely passive systems for three days following the LOCA. During this time, containment pressure continues to rise as you can see from this curve, but stays below the containment design pressure. At three days when active systems which are PCC pool refill and vent fans stop, the pressure rapidly drops and stays below acceptably low level in the long term.

The containment pressure is sufficiently low to maintain safe shutdown conditions below 215.6 decrease Centigrade or 420 degrees Fahrenheit in the rear to core. Therefore, this containment pressure would meet the intent of GDC-38.

As I noted, the staff determination is pending on resolution of RAI 62.140.

Next, Allen Notafrancesco will begin his presentation.

MR. NOTAFRANCESCO: Okay. My responsibility was to provide the support for the order calculations, and at the time -- I'm just going to give you a little background -- considering this as an ESBWR, there's a tight coupling between the reactor coolant system and the containment. So we selected the MELCOR code to be adapted to the unique features of the ESBWR.

The MELCOR code uses a state of the art lump parameter approach. It has a fully integrated system between the reactor coolant system and the containment, and in our assessment we focused on ESBWR phenomena and performed targeted code assessments. Because MELCOR has been categorized as a severe accident code, we had to go and do some key assessments to qualify and validate the code, that it does do thermal hydraulic DBA-type analysis.

Some of the models came from the CONTAIN code, which is also our licensing code for containment analysis, but it's restricted to containment phenomena. It doesn't deal with the reactor coolant system.

So what we did, we contracted with Sandia National Laboratory. We did targeted assessments related to the ESBWR. The various assessments were PANDA and PUMA. Those are all different types of assessments that were related to ESBWR.

The next slide is just to go over a quick overview of how I'm going to present this, is provide a quick background of the plant and our calculation approach; the MELCOR EWBWR model; and our long-term cooling calculation focusing on pressure.

There's two distinct parts or periods to the transient. There's the first three days, and then there's post three days out to 30 days, and I'll get into the different aspects of that.

Historically when we do containment audit analysis at the agency, we take a bounding approach in relationship to peak pressure and long-term pressure and temperature. When I say "bounding," we maximize the mass and energy into the containment which we assume is a closed system, and we minimize its transport of energy outside.

And some of the aspects we look at is looking at the worst pipe break, usually a large steam line break or recirculation line break. We look at the limiting single active failure. Our boundary conditions could be extreme tech spec values. We're looking at pressure. We' probably use the upper bound for peak initial pressure of, let's say, 16 psia.

Our modeling philosophy is when there's modeling inaccuracy or uncertainties, we'll index inherent biases to assure that we produce conservative pressure calculations.

Now, this is just an overview of the ESBWR, the relationship of the wetwell, the GDCS pools. The key systems I want to know here are the main vents, the vents between the drywell and suppression pool; the PCCS heat exchangers. Those are the red dotted areas, and there's six of those systems. The main portion is a heat exchanger with two modules, and then there's a fan coupling between the vent gas pipe to a pipe going to the GDCS pool.

The key concept of the long-term cooling is to take the decay heat from the core, which is transported by steam, to the PCCS heat exchangers and that upward pool with evaporate, and that's how it's going to control the pressure.

As part of our logical dissection of the phenomenon, what I have here is the passive period, which is a three-day period. Basically, I want you to focus on the left side. The right side in the middle is the specific phenomenon of processes. Then we have our validation and our MELCOR reference documentation, but I just want to familiarize the key aspects of this period is the blow-down period in which the large break is going to uncover the vents between the drywell and the wetwell, and that slug of energy is going to be absorbed in the suppression pool.

The pressure will eventually go down. The GDCS will refill the RPV; the recovery period; and then the long term is where the PCCS heat exchangers will be a dominant player.

Some of the key phenomenon in the ESBWR is the pressure will be dictated by what is going to happen in the wetwell, and some of the assumptions that heighten the wetwell is bypass leakage between the drywell and the wetwell, and the trickle of noncondensable gases from the drywell going to the

PCCS which will tend to plug up the lower portion of the PCCS PIPING.

This slide is a similar slide as the previous one, but it's for three days to 30 days. This is when the fans are on. At that time the upper pool is somewhat uncovering the top portion of the PCCS heat exchangers, and they're exposing tubes to atmosphere instead of water, and then there's a refill period, and then the fan is going to continue going and then it will stabilize out in the long term and you'll see the plots.

Here's another breakdown of the ESBWR plan in which we included the segmentation of the nodalization of the different portions of the containment. The suppression pool is nodalized to maximize stratification; the same thing with the wetwell gas space; and what you see here is you'll see vacuum breakers. There's vacuum breakers between the wetwell and the drywell, and there's the drywell to wetwell bypass path.

And the next slide will break that down further. The MELCOR on the left side is the RPV nodalization. Basically, what we're using the model to -- besides blowing down the initial inventory of steam and water in the vessel -- we're trying to also boil water for the long term, and that's what we're doing here.

At the same time, we're assuming a radiolysis effect of water to supply some noncondensables that will eventually be a factor in degrading the PCCS a little bit.

The middle slide is a better representation of the wetwell break-up of the nodes. What we're trying to do is maximize the energy input into the wetwell. The nodes are set that if the vacuum breakers pop, they'll get more noncondensable rich mixtures going back into the drywell. The right side is how we grouped the PCCS units. There are six units so that we have a bank of two consolidated and a bank of four consolidated units that provide the calculational efficiency that we need.

The next is the TRACG plant schematic. Since they're using TRACG and one of the artifacts of TRACG is their artificially nodalizing some of the drywell air space, and that's one of the issues we've worked out with General Electric to try to induce more mixing because we've got to get the noncondensables to the wetwell, which tends to drive up the overall system pressure, and if you have too much nodalization, you'll tend to trap. You'll trap noncondensables, and it's not a player in the pressurize.

The next slide is basically a listing which I describe about suppression pool stratification, wetwell gas stratification. We also modeled, and consistent with the GE model, is we reduced a number of heat sinks that are modeled in the -- we're not modeling all of the heat sinks in the containment; just enough walls to connect with the wetwell and the wetwell connecting out to the reactor building.

MEMBER SHACK: Can you just go back over that for a second on this nodalization with TRAC? Are you arguing that that's a less conservative one or there's something non-realistic about introducing the nodalization?

Doesn't it let them look at things like stratification and such? I would have thought it was a plus.

MR. NOTAFRANCESCO: Well, not for the drywell because in the drywell the main issue is to try to get -- it depends what you mean by stratification. If it's steam stratification, that's a nonconservative assumption because then it would push the noncondensables in the lower drywell.

MEMBER CORRADINI: I think Allen is agreeing with you, but he's giving you his explanation of why he agrees with you. He's looking in this DBA calculation to give the upper bound on pressure all the time, and --

MEMBER SHACK: Yes, but he's just forcing it that way.

MEMBER CORRADINI: Well, I mean, I'm putting words in your mouth, Al, but let me say it differently. I think Bill was asking if they nodalize it, and let's assume they do it right, that could potentially take us more to a best estimate. But that's not your objective in the MELCOR calculation.

MR. NOTAFRANCESCO: No.

MEMBER CORRADINI: Okay.

MEMBER SHACK: That answers my question.

MR. NOTAFRANCESCO: Just a sidebar. In typical state of the art containment analysis, this is really still one parameter. Some of this field code stuff or CFD is an emerging technology that lacks even test data. So --

MEMBER CORRADINI: You're showing your prejudice, but that's okay.

MR. NOTAFRANCESCO: Well, I'm showing practicality.

So and typically with any other BWR Mark 1, 2 or 3, the drywell is mixed, is assumed uniformly mixed, and here we're just taking it to the next level. So because in the early analysis we were getting some trapping in the GDC airspace, and we tried to get around that by putting two flow pads to induce counter-current flow and better mixing. So that's what we try to do. We go more to physics. We're going to bias on a conservative end.

So like I said, we reduce the heat sink inventory. We are going out 30 days. So that puts some conservative bias to that.

There is PARs in this system. PARs is passive autocatalytic recombiners. They're not credited in the first three days. They are credited three days on, and the way it's credited is that all radiolysis shuts off.

MEMBER CORRADINI: Does that mean that they're designed in such a manner that they have enough capacity to more than account for whatever might be produced by conservative radiolysis?

MR. NOTAFRANCESCO: Well, that's the intent of what we see. GE hasn't designed it yet. So those are the assumptions.

MEMBER ARMIJO: If these things are

passive, why aren't they credited during the first phase?

MR. WAGAGE: Because they are not safe related system. They are known to categorize as a safe related system.

MEMBER ARMIJO: That comes from GE, to decide it or not.

MR. WAGAGE: Yes, that's right. We decided to create up to three days.

MEMBER CORRADINI: Does the Applicant want to say anything at this point?

MR. MARQUINO: That's right. They are a witness system. They are not safety related. Therefore, we don't credit them before three days even though realistically they would have some effect, but we take no credit in the analysis for that.

MEMBER CORRADINI: How much energy do they use? What's their power?

They require -- they have to be powered.

MR. MARQUINO: No, they're not.

MEMBER CORRADINI: They're not powered?

MR. MARQUINO: No.

MEMBER CORRADINI: So it's a catalyst without any sort of heating of the catalytic surface.

MEMBER ARMIJO: The recombination starts

the --

MEMBER CORRADINI: Right, but every catalyst has some nice temperature that it likes to cook at. So my question is it doesn't need to be heated to any temperature.

MR. MARQUINO: No.

MR. NOTAFRANCESCO: It needs a minimum threshold of hydrogen to get things started.

MEMBER CORRADINI: Which is what?

MR. NOTAFRANCESCO: Point, five percent or something to that.

MEMBER CORRADINI: Thank you.

MR. NOTAFRANCESCO: Okay. And what we see here is the bottom line drywell pressure trace calculated by MELCOR. It's in log plot. We're going out 30 days. The first 800 seconds is typically the blow-down. The vent system, the main vent is open and the pressure of the drywell is relieved through that vent system and the energies going into the suppression pool.

Then on the way in that sequence early on, the DPV valves open up. They help the depressurization of the core and then there's GDCS flow, which is basically the pool at a higher elevation, and that starts filling the RPV.

The RPV will be filled, and the water will start to flow out the main steam line break. Steaming will be shut down for a while. That's why you see a dip around 800 to 1,000 seconds. Then the subcooling will be heating up and RPV steaming will start rapidly increasing.

At that time, the PCCS will start to be a player, and up to three days the pressure will slowly go up because of the effect of bypass leakage and the noncondensables fighting the resistance within the PCCS piping, at which time, at three days, the active systems will start to be drawn in.

MEMBER CORRADINI: They're credited at that point. They're allowed to be credited.

MR. NOTAFRANCESCO: They're allowed to be credited.

Okay. The next plot is the first three days compared to TRACG. Overall we get a good match with TRACG, considering we have a different independent code and a different pedigree. So we get good results, which is good.

I discussed the passive portion, but the intervention period, PARs are credited. So radiolysis was shut down. There are six fans available, but four fans are working. One is assumed to be out on tech spec, and one is assumed to fail. So that leaves two, and that's why we have the banking of the PCCS as a two and a four calculation. It's efficient that way.

And the upper pool refill will stop because at the time of three days --

MEMBER BROWN: Before you help me, you've got bars on one graph and then kilopascals on the next graph, and I don't know how to calibrate that.

MEMBER CORRADINI: Just divide multiple bars by 100 and you've got kilopascals.

MEMBER BROWN: But how do you get that into pounds per square inch?

MEMBER CORRADINI: We won't give you that.

PARTICIPANT: Fifteen.

MEMBER CORRADINI: Multiply by 14.5 bars.

MEMBER BROWN: Okay. So a bar is 14.7 psi?

MR. WAGAGE: A hundred kilobars is 14.5 psi.

MEMBER CORRADINI: Hundred kilopascals.

MR. WAGAGE: Hundred kilopascals.

MEMBER BROWN: I'm not understanding one bar.

MEMBER STETKAR: One bar is 14.5 psi.

MEMBER CORRADINI: Write it down.

MEMBER STETKAR: The test is after class.

MR. NOTAFRANCESCO: The design pressure is 45 psig.

MEMBER BROWN: Okay, and how many kilopascals per bar or the other way?

MR. WAGAGE: Hundred kilopascals per bar.

MEMBER BROWN: I see in here.

MS. CUBBAGE: It appears that Slide 16 and 17 have identical scales on the left but different labeling.

MEMBER BROWN: Exactly. Thank you. I didn't know what the weight was anyway, but the numbers were just off by 100. Is that what you're trying to tell me?

MS. CUBBAGE: Yes.

MEMBER BROWN: All right. Thank you.

I'm taking over now sine I have no idea what you're talking about. Go ahead. You can continue is what I'm telling you.

MR. NOTAFRANCESCO: Okay.

MEMBER BROWN: Mike gave me permission to tell you to do that.

MR. NOTAFRANCESCO: In trying to calculate post three days of the ESBWR long-term pressure, there are some issues we had with GE that we're converging on, and one of the issues was how the upper pool was being refilled. In the DCD it is a constant 200 gpm, and yet they provided some level control, and there's a tray in the GCDS pool where the condensate and the fan discharge is supposed to be designed, but it's not designed. So we had some issues with them.

What this means is that it affects the flow of fan, fan flow. Okay? These assumptions will affect fan flow, and so we tried to get on the same level.

Okay. The next slide will be helpful. There you go.

It's our contention since they run a condensate tray of ten inch head on the discharge, we embedded it in our MELCOR code to provide that fan head. We have a 200 gpm. So the upper pool keeps increasing, and so our top curve, the red curve is what we think is the actual audit calculation.

The blue curve is the curve that is in the DCD, which provides a more optimistic fan flow or the end product is the fan flow, which is the TRACG calculation. So that is where RAI-140, Supplement 5 gets involved, is to try to reconcile the difference.

The green curve is a MELCOR calculation in which we try to match the blue curve with the same assumptions. So that's why there's some difference when we say audit versus confirmatory here, but basically what you see here is the signature of the profile for long-term cooling.

So the bottom line results -- what I'm trying to say here is that the passive period in the first three days, we have a good match with TRACG and we're generally satisfied with comparisons.

Our audit calculation with MELCOR, with the proceed design calculation, we're still about 24 percent margin at 30 days. So that leads us to where we have some soft areas as trying to reconcile ultimately how the TRACG calculations are documented in the DCD, and that's where it needs to be pursued.

But basically we're confident we have a good, conservative calculation in representing the behavior of the ESBWR facility.

Do you want to see any more?

MEMBER CORRADINI: Questions by the Committee?

(No response.)

MEMBER CORRADINI: Mr. Chairman.

CHAIRMAN BONACA: Thank you very much.

When is the letter or whatever is due? What is happening?

MEMBER CORRADINI: We're required by SECY to get back a response on a per plant basis, and we're the first ones up, and the deadline is April 2010. We thought it would be reasonable since many of the folks here were at the Subcommittee meeting two weeks ago to inform the rest of the Committee as to essentially the comparison between the staff's audit calculation and the Applicant's calculation now that they've submitted what we think is their final supplement for the long-term containment cooling, long-term core cool.

MEMBER BANERJEE: Right, but there have been many very detailed questions that were on the table.

MEMBER CORRADINI: Those were all given to us by our consultants, and we're going to look at those as we proceed forward. All of those questions --

MEMBER BANERJEE: but they will have to be resolved in some way or the other before the --

MEMBER CORRADINI: Correct, correct. They have to be resolved in some way or the other. I think Dr. -- well, we've got two sets, one from Dr. Wallis, one from Dr. Kress. Dr. Kress' had -- if the Committee wants, I can summarize.

Okay, but anyway, we got a series of two or three major issues from Dr. Kress. Dr. Wallis' could be summarized into four issues. One of the three was it's fairly lengthy because he analyzed Supplement 4 and came up with a range of questions. I'm not sure necessarily if he's happy with Supplement 5, but he is looking at it.

But I think the issues by our two consultants in some sense overlay relative to fan performance, containment cooling. The big one that's still out there is staff is still -- the only thing we didn't bring up today, and it was my decision not for them to do it, is staff is still evaluating the temperature and pressure sensors that are being used with the vacuum breakers to determine any sort of out of bounds leakage in isolation of the vacuum breakers, and that's still being analyzed in another -- I think that's RAI-148 -- and they're looking at Applicant's response to that now.

But that is probably the big one that we have reviewed by two weeks ago that has yet to be --

MEMBER BANERJEE: Well, the other issue was the -- it may not be an issue -- was the LFL limits at various points.

MEMBER CORRADINI: Right, correct. We have yet to see any calculations by anybody to comment on them.

MEMBER BANERJEE: Right. It's only --

MEMBER CORRADINI: It's a question.

MEMBER BANERJEE: It's a question. We are asking for information.

MEMBER CORRADINI: And we still have to get something back. That's correct.

MEMBER BANERJEE: But would you want to have that resolved?

MEMBER CORRADINI: We are not going to until all of those things are satisfactory to this august body.

MEMBER BANERJEE: Fine.

MEMBER CORRADINI: Okay? That's kind of where we sit.

MEMBER BANERJEE: All right.

MEMBER BROWN: So there is no problem with only having about three-tenths of a -- or 30 kilopascals?

MEMBER CORRADINI: I'm going to ask you how many psi that is.

MEMBER BROWN: Three --

PARTICIPANT: Tenths.

MEMBER BROWN: No, it's three psi. So --

PARTICIPANT: Four, but --

MEMBER BROWN: All right. Close enough.

MEMBER CORRADINI: Okay.

MEMBER BROWN: Out of all that, I mean, that's five percent margin is okay or six percent margin to the design limit.

MEMBER CORRADINI: You're asking me or asking the staff?

MEMBER BROWN: Yes.

MEMBER CORRADINI: Ask the staff.

MEMBER BROWN: I don't know what's been accepted in the past. That just seemed kind of close. That's all.

MR. WAGAGE: Margins accepted in the past is closer to the design pressure is just below the -- the calculated pressure is just below the design value for AP-1000 and AP-600. The calculated pressure is based below the design value. It satisfies GDC-50, which requires that LOCA -- the containment has to be designed to accommodate LOCA generated containment (unintelligible). As long as it stays below the design value, it satisfies.

MEMBER BROWN: So it can be .0001 below it and that's okay?

MR. WAGAGE: If the calculation is a bounding value. If you don't believe that it is above that, then it's acceptable.

MEMBER CORRADINI: I think the point kind of goes back to Al's philosophy on this, is they cautiously did the MELCOR audit to be bounding and over estimate as best they could all the pressure loading. Is that a fair statement?

MR. NOTAFRANCESCO: Sure.

MEMBER BROWN: So the bounding is supposed to be more conservative.

MEMBER CORRADINI: Well, the bounding essentially brings you closer to the margin, closer to the design pressure. Excuse me.

MEMBER BLEY: The conservatism is also built into the limit.

MEMBER CORRADINI: Yes, correct.

MEMBER BLEY: That's where the real protection is.

MR. NOTAFRANCESCO: The overall capacity is over 150 psi of the system.

MEMBER BROWN: I just want to concur, but I mean --

MR. NOTAFRANCESCO: It's not unique. I've seen other plants come close to the design.

MEMBER CORRADINI: It's not uncommon in containment analysis to have this as essentially a pass. In current plants, given they use essentially the same analysis technique that Al had indicated, a conservative loading calculation compared to an essentially design calculation, where there is margin in the design calculation -- in the design limit. Excuse me.

Is that a fair statement?

MR. WAGAGE: Could you repeat that again?

PARTICIPANTS: Yes.

MEMBER BANERJEE: Well, I think there are aspects where the limit itself has a margin, but there can be things which are unforeseen which would push these pressures higher, of course.

MEMBER BROWN: That's why I don't like being that close.

MEMBER BANERJEE: Yes, but these are very bounding calculations.

MEMBER MAYNARD: You put the margin. I mean, you have conservatism in the limit. The margin of the calculation --

MEMBER BROWN: Yeah, I understand what you're saying.

MEMBER MAYNARD: If you're going to put a delta in there, you don't need the conservatism in the other.

MEMBER BROWN: I understand. It's just I don't know -- when you calculate the number, I don't know how much margin is in there.

MEMBER CORRADINI: Staff is not comfortable with --

MEMBER BROWN: -- and nobody made any comments about how much margin there was in the line. So we've been discussing how we don't like to exceed various design pressures in other meetings and on other projects, and so that one comes pretty darn close, and that's why I asked the question, for unknown unknowns.

MS. CUBBAGE: And we also evaluate in Chapter 19 spaces severe accident capability of the containment as well. So this is the design basis limit here.

MEMBER BANERJEE: By analogy, Charlie, when you have peak clad temperature, sometimes in these numbers it comes within two degrees or something.

MEMBER BROWN: I don't know. A transient, short time, not going to do anything. I understand that point also. It's not sustained.

MEMBER CORRADINI: Other questions?

Mr. Chairman, I still turn it back to you.

MEMBER RAY: Well, wait a minute. I think we have a minute. Can I -- with the staff here, they may have something to day now. Eileen is not here.

MEMBER CORRADINI: Oh, you're going to talk to them about --

MEMBER RAY: I have the opportunity to have Sanjoy here, which is something I want to take advantage of.

At the same time you were having your meeting, we were having an AP-1000 meeting on the same subject, and Mike started off by referring to this May 8th he called it a staff SRM. The position that was taken in that meeting both by the applicant and by Eileen was that on the long-term cooling issue, on the amendment, which this May 8th letter doesn't speak to an amendment; it only speaks to certifications and the COLS; that it may be resolved as part of the amendment, which we all know we're busily working to complete, or it may not, in which case it will be addressed after the amendment is done.

I at that time didn't know about this May 8th memo. So I'm bringing it up here now. The discussion at the AP-1000 meeting basically said we're giving you this briefing for information purposes, but you don't -- at least now I'm using my own words --

you don't need to figure out now how you're going to resolve all of your questions, and we haven't even heard the staff's questions yet, before the expected closure of the amendment to the AP-1000. It may be after that. So relax, which is a different picture than we have here that Mike has given us based on this May 8th memo.

So I guess I would just say I am not sure whether this May 8th memo is intended to apply to the AP-1000 amendment or not.

MEMBER CORRADINI: Harold wants an exception.

MEMBER RAY: But if it is, that's a different view or a different outlook than we got in the meeting that was going on at the same time his meeting was going on.

Specifically then the question is, well, are we going to have to, in fact, conform the AP-1000 amendment approval to this injunction that the ACRS advise on the adequacy of the design basis of long-term core cooling approach for each here it says new reactor design. AP-1000 in some people's minds is a new reactor design in the form of the amendment.

But leaving that aside, in any event, the point is that it's not clear that we're on the track to resolve this. I understand ESBWR is, and I would just --

MEMBER CORRADINI: Don't assume that. We're on a track to report something.

MEMBER RAY: To, yes, resolve what the ACRS' response is to this request. That's what I meant by resolve it.

We're not necessarily on that track in the AP-1000, and I just want to make that clear.

MEMBER BANERJEE: Well, we will respond if asked to.

MR. DIAS: Will comment at a later time. Every model has to answer to that.

MEMBER RAY: Now, wait. I just got through saying this speaks to design certifications and to COLs. It does not speak to amendments to design certification.

MEMBER BANERJEE: Is that just the fine point of the wording or --

MEMBER RAY: I am. I became a lawyer long after I was an engineer. I'm just telling you --

PARTICIPANT: I'm just telling you it seems like a design served to me.

MEMBER RAY: I understand that, but if the point is going to be, well, we've got news for you.

You are going to have to take a position on long-term cooling on the AP-1000, then I've got news for the staff, and that is they had better get us something to chew on more than the briefing we got from the Applicant in the last Subcommittee meeting.

MEMBER BANERJEE: Well, to be fair, Harold, I think we left it open as to whether it was possible to do or not before we had resolved the issue for the current LWRs.

MEMBER RAY: After you were gone, we had a rather lengthy discussion of this, Sanjoy, and we absolutely explicitly said we are not currently planning, and I say all of this because you know what is going to happen tomorrow. We're going to have a discussion where who knows; it could come up. So I just want to --

CHAIRMAN BONACA: Well, we will pick it up again, this issue, when we have this report.

MEMBER RAY: That's fine. I just raised it here now because of the conjunction with what was being discussed.

MEMBER CORRADINI: Harold and I had a side conversation about it, but I think it's fair to say that kind of at least this AP-1000 since I was at his meeting the second day or at one of the days when this started to be brought up, it really is not fish nor fowl. So if you take it by the letter of the law, it doesn't apply, but it seems to me by the spirit of it, it's going to have to be addressed in some manner, and so far what we've heard in his Subcommittee is not enough to address it.

MEMBER RAY: Thank you.

MS. CUBBAGE: I'll take that back for the other part of our Licensing Division to chew on, but I would just offer my impression, not having been here for the previous meeting, that I think you would only be addressing it to the extent it was part of the amendment.

MEMBER RAY: Well, but it is inevitably a part of the amendment in that it is, you know -- you mean to the extent that resolution of GSI-161 is part of the amendment.

MS. CUBBAGE: Right.

MEMBER RAY: Well, that is right. In other words, the Applicant has to bring in a resolution,b ut if you were at the meeting that I'm referring to and the Chairman wants me to stop now, but the point is if you were there, you would think maybe we were being presented with a resolution.

MEMBER BANERJEE: They seem to want a

resolution.

MEMBER RAY: That is right.

MS. CUBBAGE: To the extent that it's open as part of the amendment, then yes, but if it 's issues that have resolution and are not being reopened, then that's a different story.

MEMBER RAY: Well, we understand. We are just trying to look ahead.

MS. CUBBAGE: I understand, but I'll take it back.

CHAIRMAN BONACA: Are you sure?

MEMBER CORRADINI: I'm in charge of a boiler. We've gone astray.

MEMBER RAY: I waited. I didn't say a thing.

MEMBER CORRADINI: I know. I was just teasing with you.

CHAIRMAN BONACA: With that, I want to think the presenters. That was a good presentation, and at this stage we are one hour and 20 minutes ahead of time. So I think we should take one letter and read it through. We need you around for recording additional meeting we have at 3:30, but we will do the letter now off the record.

(Whereupon, the foregoing matter went off the record at 2:30 p.m. and went back on the record at 3:31 p.m.)

CHAIRMAN BONACA: Let's go back into session.

We have now a presentation on Reg. Guide 1.151, and Otto Maynard will take us through the presentation.

MEMBER MAYNARD: All right. Thank you.

CHAIRMAN BONACA: The last one?

MEMBER MAYNARD: Yes, it is. Thank you, Mr. Chairman.

(Laughter.)

MEMBER MAYNARD: Either way, whatever, yes, this is the last one.

The subject of this is Reg. Guide 1.151, Rev. 1. That's on instrument sensing lines. Rev. 0 of this reg. guide was issued early in the 1980s, and subsequent to the issuance of Rev. 0, there have been a number of operating industry events, operating experience where trapped and evolved gases and other things have caused inaccurate instrument readings.

So the NRC has addressed some of these through a combination of information notices and bulletins. The industry has made some modifications and changes in the way they're doing business.

In addition, there has been an industry standard that's been revised and developed to address a number of these things.

So the NRC has prepared Revision 1 to Reg. Guide 1.151 to incorporate a number of these things, update the guidance not only for the existing plant, but also to make sure for new plant designs that they have the latest guidance.

The copy that we received in our status report is not the latest copy. It's very close, but it did not incorporate some of the public comments. The latest rev. incorporates some of the comments from the public.

So Zena has passed around what you have. The hard copy in front of you is the latest Rev. 1 to Reg. Guide 1.151.

During our Subcommittee on this a couple of days ago, the major topic of discussion really centered around staff position four relative to the trapped and evolved gases, and it's really a question of whether or not the staff was taking exception to or endorsing the standard relative to this area, and so that's one of the specific things that we'll be talking about today.

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

Nguyen and proceed with the presentation.

MR. KHOI NGUYEN: Thank you.

Good afternoon. My name is Khoi Nguyen, Digital I&C Branch, Division of Engineering, Office of Research.

I will go over the presentation of proposed Revision 1 of Reg. Guide 1.151, Instrument Sensing Lines. For some of the changes, we update the endorsement of ANSI standard 67.02.01, 1999, with one exception, that for the portion associated with the sample lines it's out of the scope of the reg. guide which only covers the instrument sensing lines.

We also updated reference to IEEE Standard 603, 1991, and we endorsed IEEE Standard 622, 1987's version, to cover the filings associated with heat tracing system used for freeze protection.

Because we update the endorsement of the ANSI standards, we removed the supplemental guidance previously in the Rev. 0 of the reg. guide. It's now covered by ANSI standard and IEEE Standard 622.

So we will go over the changes to the (unintelligible). In Position 1, besides removing the supplemental guidance, we exclude the standardized portion in the ANSI standard from the endorsement.

Position 2, we clarify the isolation

requirements, which is excluded from ANSI standard as it applied to sensing lines and entertaining the containment boundary.

In Position 3, besides removing the supplemental guidance, we endorse IEEE Standard 622, as I mentioned earlier for heat tracing systems.

Now, I go to the interesting Position 4. We provided the guidance not covered in ANSI standard for sensing lines, taking into account lessons learned from the measurement errors due to the evolution of this (unintelligible) gases.

Position 5, we deleted to remove the supplemental guidance.

And Position 6, we deleted to remove the disclaimer associated with the previous version of the ANSI standards which are no longer applicable.

The benefits of updating the reg. guide is to enhance the reactor safety by, one, addressing the most current ANSI standard and IEEE standards on the safety system endorsed by the NRC, and the second is to addressing the operational events in which evolved gas in station lines have affected measure of water level and provide guidance to prevent events.

In the previous Subcommittee meeting, we had the comments on Position 4. We appreciate the comment, and we come back to review the ANSI standard, and what we found was the standard particular provide guidance to prevent the trapped gas and evolved gas. It also recognized the problem with the instrument errors due to the depressurization, but it will no further provide any guidance.

So we believe that we still need Position 4 to supplement the guidance for our ANSI standard, but we need to change the language to affect the concerns from the Subcommittee members.

I will go to the -- here is what we found. I said to put in here Section 5.1.2(n) in ANSI standard, which recognizes the inaccuracy in the water level, as I said earlier. It is just warning -- it just like recognize the problem and warning that the problems shall be considered, but it doesn't provide any guidance.

So here is the current regulatory Position 4. We have in the proposed draft one. We presented to the Subcommittee, and the second bullet is the proposed change to the Position 4, in which we add to clarify. Even though the guidance in the ANSI standard is adequate, but it is not sufficient enough to cover the trapped gas. So we would like to change the language to in addition to the design guidance provided by ANSI standard for insuring sensing lines. Provisions should be made to (a) determine the potential impacts of trapped evolved gases in issuance sensing line during or following depressurization event and need to mitigate such impacts as long as the associate measures are required for monitoring the plant or for operating the service system.

VICE CHAIRMAN ABDEL-KHALIK: What do you mean by "as long as"? Do you mean if and only if? I mean, what if somebody does it for everything?

MR. KHOI NGUYEN: Well, if we don't need these indications for operating the service system, we have another means to operating the plant, and the safety significance is low. It's not -- I don't want to say it's not important, but it's not significant to be considered.

So if these instruments are the only instruments to use to operate the plant during or following any nuclear incident, and then this will be considered.

MEMBER STETKAR: This reg. guide applies for current operating reactors and new operating reactors.

MEMBER MAYNARD: Okay. No.

MEMBER STETKAR: Does it?

MEMBER MAYNARD: Well, the current operating reactors could commit to this if they want to. They're not required to commit to this rev.

MEMBER STETKAR: Okay, all right.

MEMBER MAYNARD: So it's only if they make certain changes that require them to or that they do voluntarily.

MEMBER STETKAR: Does this apply though to all new reactors?

Where I was getting to is the difference between RTNSS and safety systems, which is a little bit supporting what Said was mentioning. So does this reg. guide apply to new reactors that are coming on line?

MR. KHOI NGUYEN: This reg. guide is supposed to apply to both the new reactor designs, but the old designs of existing operating plants can choose to follow if they want to.

MEMBER MAYNARD: I kind of read this statement -- and I'm glad we're in this discussion -- as saying that it has -- you have to take this into account basically for the duration or for whenever you're counting on the system, whenever you're crediting this indication for whatever actions.

MEMBER STETKAR: The problem is it says safety systems, which for example in some of the new passive plant designs is a relatively small inventory of the systems. If I were a licensee, I would say a RTNSS system is not a safety system.

MEMBER ARMIJO: John, it says for monitoring the plant or for operating the safety system. It doesn't say for monitoring the plant's safety systems.

MEMBER STETKAR: Okay.

MEMBER ARMIJO: I see it broader, but I don't know if that's what the staff intends.

MEMBER SIEBER: If it would show up in your emergency procedures.

MR. NOTAFRANCESCO: That's what the staff intends, is more in the plant is broader and then to operating the service system, the two purposes.

MEMBER SIEBER: It would show up in your emergency procedures. Then you would have to --

VICE CHAIRMAN ABDEL-KHALIK: I guess I'd feel more comfortable if you were to replace "as long as" with the word "when."

MEMBER BROWN: When do you have instrument systems that you don't use for monitoring the plant, is there an example of one?

MEMBER STETKAR: I was more concerned about the phrase "safety system."

MEMBER BROWN: No, I understand that.

MEMBER STETKAR: Are we restricting this to a relatively small subset of equipment in the new plant designs?

MEMBER BROWN: Yeah, and I was addressing the other piece of that where it says just if you're going to use the measurement for monitoring the plant, and I'm trying to picture in my mind a measurement or monitoring readouts that aren't used for monitoring. They all monitor. Otherwise you don't have a choice. It's very broad.

MEMBER STETKAR: The flip side could be interpreted as this could apply to everything.

MEMBER BROWN: Yes, which I don't necessarily disagree with maybe, but it's not a backfit. I mean, they excluded it from backfit, and if it's a new point, you ought to be designing it to be right I mean, who wants an instrument that may be wrong?

MEMBER MAYNARD: Well, I think this is covering it by saying that when it's required for monitoring or for actuation of controlled synthesis.

MEMBER BLEY: I agree because I don't know what would be excluded.

MEMBER ARMIJO: Yeah. Well, it's everything.

MEMBER SIEBER: Well, I would interpret it as anything that's called out in an EOP.

MEMBER BROWN: That's an interpretation. I wouldn't. I mean what about normal operating procedures? You're monitoring something and it's wrong.

MEMBER SIEBER: Yeah, but you aren't going to have a big pressure transient for your normal operation.

MEMBER BROWN: I don't know. Is a big down-power maneuver just because you lose a load somewhere? Is that a --

MEMBER SIEBER: Down-power make the pressure go up.

CHAIRMAN BONACA: Well, we have a few interpretations here. We had better --

MEMBER BROWN: That's a nuance. I wouldn't interpret it that way. Monitoring is monitoring regardless of the conditions of the plant.

MEMBER ARMIJO: And it's not limited to safety systems the way it's written.

MEMBER BROWN: You're right.

MEMBER SIEBER: You're right.

MEMBER ARMIJO: And it doesn't matter. as long as that's the staff's intent that it's not --

VICE CHAIRMAN ABDEL-KHALIK: But you know, does this become overly burdensome then?

MEMBER BROWN: Well, it's not a backfit. It says it does not intend to improve any imposition or backfit in connection with this issuance. So operating plant today don't have --

MEMBER SHACK: But it still could be a burden for a new plant.

MEMBER MAYNARD: I think the operative word there is when it's required for monitoring. That takes care of whether safety or whether it's RTNS or whatever, but if it's required for monitoring, you're going to want it to work. So I don't see if it were a burden --

MEMBER BLEY: I don't think it's a burden in a new design.

(Simultaneous conversation.)

MEMBER ARMIJO: I think it's pretty broad when you need it, and it's not limited to safety systems.

MEMBER BROWN: I guess I can live with the way it is.

MEMBER SIEBER: Well, I don't want --

MEMBER STETKAR: A new plant you can design it right. Would you love to walk into the plant and know that some of your stuff may not read right, but you don't know when exactly? Yeah, that's really a great way.

MEMBER SIEBER: Well, I don't want to stray away from the idea of noncondensable gases, but do you worry about flashing in reference like when you get a big pressure decrease?

MEMBER BROWN: In some cases you would.

MEMBER SIEBER: Yeah, but this doesn't talk about it. It talks about noncondensables. It doesn't talk about flashing.

MEMBER BROWN: Well, that's true.

MEMBER SIEBER: And flashing in --

MEMBER SHACK: Well, trapped, evolved gases, when it flashes it's on on gas.

MEMBER BROWN: No, you can get flashing if you have pressurization. The saturation, depending on the saturation temperature of the water, we got that in steam generator reference lines -- in --

MEMBER SIEBER: Absolutely.

MEMBER BROWN: -- as well as in pressurizer lines or pressurizers. So we had to actually incorporate futures to prevent that from happening so that we maintained satisfactory level indications.

So we had a reservoir that had, you know, a condensing pot, whatever you want to call it, and then there was a little reservoir lip to allow it to drain over, and it was a lot of --

MEMBER BLEY: Just a point. This refers to the GDCs. They're laid out on the previous page. GDC-13 is to provide an monitor variables and systems over their anticipated ranges for normal operation or anticipated operational occurrences and for accidents. It's for everything. It's the whole thing.

MEMBER BROWN: Yeah. Well, okay. That's good.

MEMBER BLEY: And that's on the previous page.

MEMBER BROWN: Yeah, I didn't go back and read all of that after the work you've done.

MEMBER SIEBER: But flashing in the reference lake does occur.

MEMBER BROWN: Absolutely.

MEMBER SIEBER: And it can give you significant differences between the actual level and the indicated level, and I don't see that here.

VICE CHAIRMAN ABDEL-KHALIK: Well, you can insert the words "PAR flashing" after "evolved gases."

MEMBER SIEBER: Yeah, we could put it, but it doesn't say it now.

MEMBER BROWN: Flashing is not evolved gases. There is a difference. I agree with you, but if you don't have a big transient type plant, it was very relative to the naval nuclear plants because as you noticed very rapid transients are required.

MEMBER SIEBER: That's one of the reasons why you don't --

MEMBER BROWN: Everybody used to have rapid transients.

MEMBER SIEBER: One of the reasons why you never seek insulation on a reference like piping in a plant, there's nothing in any of this that talks about that. You may want to think about adding something to that effect.

MR. KHOI NGUYEN: You want to add the last --

MEMBER SIEBER: Because it's condensable, but at the time that that it occurs, it's dead.

MR. KHOI NGUYEN: Okay. I will add flashing after it give off the ashes.

MEMBER SIEBER: Okay.

MEMBER BROWN: Or trapped.

MEMBER SIEBER: And/or Flashing.

MR. KHOI NGUYEN: Okay.

MEMBER MAYNARD: Okay.

VICE CHAIRMAN ABDEL-KHALIK: And you're going to replace "as long as" with something else?

MEMBER MAYNARD: What had you suggested, Said?

VICE CHAIRMAN ABDEL-KHALIK: "During." No, "such impacts when."

MEMBER BROWN: As opposed to "as long as" use "when"?

VICE CHAIRMAN ABDEL-KHALIK: Right.

MEMBER BROWN: When required.

VICE CHAIRMAN ABDEL-KHALIK: Okay.

MEMBER BROWN: When associated measure.

VICE CHAIRMAN ABDEL-KHALIK: When the associated measure.

MR. KHOI NGUYEN: I will replace "as long as" with "when" and adding "for flashing" after log ashes (phonetic).

MEMBER BROWN: Right.

MR. KHOI NGUYEN: Anything else?

MEMBER MAYNARD: Anything else on this position statement?

MEMBER ARMIJO: That's clear now, although flashing is not discussed in the text. I don't think it's even mentioned.

MR. KHOI NGUYEN: It is here. In the discussion we didn't mention flashing.

MEMBER SHACK: As long as it is in the position.

MEMBER MAYNARD: Okay. Let's go on. We may want to come back to this because I am -- flashing is important, but we're also adding something that hasn't been discussed. I may want to come back to that subject here and just talk about that a little bit more. I'm not saying it's not important, but have we really considered all of the implications or is that covered someplace else or whatever?

I hate to kind of toss something in without some consideration of what potential. So let's go ahead with the presentation here.

MR. KHOI NGUYEN: Okay. I will highlight some of the public comments and resolution. One of the comments is the trap guys (phonetic) mention about the potential of evolved gas in water filled instrument sensing lines, but doesn't provide any method acceptable to implement the directive.

And we have revised Position 4 to provide that the method, and we also think that we don't have to provide the specific mitigation method, depends on sensing line design.

For the global BWR plants, as previously explained this problem, the discussion section already mentioned the acceptable method for the staff and other design of the sensing line may be applying other approaches, and (unintelligible) normally don't provide the specific design.

Another comment is in number seven, the reg. guide is needed for dealing with noncondensable gases, and we believe that it's not necessary to have another reg. guide to provide guidance for noncondensable gases. The instrument arrow for sensing lines due to the noncondensable gas should be addressed in this reg. guide for intimate (phonetic) sensing lines.

MEMBER ARMIJO: But you address several phenomena.

MR. KHOI NGUYEN: Right, right. So we believe that there's no need for another reg. guide for noncondensable gases.

And this is a back-up slide showing the backfill system installed to prevent a noncondensable gas (unintelligible). In some occasion there's a operator errors, either mistakenly or seen patently close this isolation valves. The pressure build up in the line and cause the narrowing instrument indication of the wire. We have the water levels, and some of the designs have been modified to avoid this problem, and there are some procedures in some plants have been modified to mitigate the problems.

MEMBER STETKAR: Khoi, I'm going to come back now. I'm reading words in what we have in front of us here. In the introduction, the introduction says, "This guide describes a method staff of the NRC considers acceptable for us in complying with the agency's regulations with respect to design and installation of safety related instrument sensing lines in nuclear power plants."

In the regulatory position, it also reiterates the fact that it applies for safety related instrument sensing lines. So now I'm not sure how broadly this regulatory guide applies, other than referencing GDC-13, which seems to be more broadly applicable than simply safety related lines.

Could you expand on whether the reg. guide applies to only safety related instrument lines or does it apply to instrument lines that are necessary for monitoring plant response regardless of whether they are safety related or not?

MR. KHOI NGUYEN: I think the scope of the reg. guide to cover the safety related instrument sensing lines.

MEMBER STETKAR: Okay. Then I'll go back to my written question.

MEMBER MAYNARD: A number of these may not be safety indications, but they're safety related from a pressure boundary standpoint and those are still covered in this.

MEMBER STETKAR: They have to remain intact from a pressure boundary. They don't have to work.

MEMBER BLEY: Read their definition of safety related. There are three pieces to it. It refers to those SSCs necessary to insure integrity of the pressure boundary, one.

Two, to show the capability to shut down the reactor in safe shutdown.

And, three, to prevent or mitigate consequences of accidents that could result in off-site releases.

I think their definition --

MEMBER BROWN: That still doesn't say normal operation.

MEMBER BLEY: It doesn't, but it refers to GDC-13, which is about normal operation. That's why we're confused.

MEMBER STETKAR: See, evolving gases in a sensing line does not compromise maintaining the integrity of that sensing line as a pressure boundary.

MEMBER SIEBER: Right.

MEMBER STETKAR: The instrumentation probably might be useless, but it certainly doesn't compromise that safety related function

MEMBER MAYNARD: But it has to be taken into account if it's required for monitoring or for operation of your safety systems.

MEMBER STETKAR: Well, but then my question comes back to the RTNSS. Does this reg. guide not apply for new reactors to systems that are defined as RTNSS, recognizing that the instrument lines must maintain their safety related pressure boundary function regardless of whether they're safety related or not, whether the instrumentation function is safety related, pressure level, temperature, that type of thing

MR. KHOI NGUYEN: I think this reg. guide that applied to the separate instrument sensing lines which cover in three definition in the safety related in the introduction section here, as you mentioned earlier, to insure the integrity of the reactor coolant pressure boundary, and the ability to shut down the reactor and maintain in safe shutdown condition and to prevent or mitigate the consequences or accident.

MEMBER STETKAR: let me ask you a specific question. Then if I think of -- without getting into a specific reactor design, a low pressure cooling system that has a pressure interlock such that you can't start that system unless reactor pressure is lower than some limit, whatever. This low pressure cooling system is not a safety related low pressure cooling system. It's a RTNSS system. The instrument legs are, indeed, connected to the reactor coolant system. So obviously they must maintain pressure integrity.

Does this reg. guide require that that pressure sensing function of that instrument must work properly during a rapid depressurization event?

MR. KHOI NGUYEN: I don't think it's required.

MEMBER STETKAR: Do you follow me?

MEMBER MAYNARD: I'm trying to think. From where I read this--

MEMBER STETKAR: GDC-13 seems to.

MEMBER MAYNARD: But if it's a system that's going to automatically come on, that's one thing. If it's up to -- if you're using the indication to decide whether to bring that system on or not --

MEMBER STETKAR: Or can prevent it from coming on if it's actually a pressure interlock. It might prevent that system from working regardless of whether it's automatically or manually initiated, if it's actually a low pressure interlock for opening a valve or starting a pump or something like that.

MR. KHOI NGUYEN: If the instrument sensing line doesn't work properly, it prevents the low pressure --

MEMBER STETKAR: Yeah, but if it's sensing an abnormally high pressure for some reason, it would prevent that system from operating.

MR. KHOI NGUYEN: So you want to question if it's --

MEMBER STETKAR: My question is: would that type of instrument -- I've given you a specific example of a type of instrument -- that is, the instrument itself, the function is a non-safety related instrumentation function because it provides an interlock for a system that is not a safety related system. The sensing line itself may declare that the structure of the sensing line may be classified as a reactor coolant system pressure boundary function, safety related reactor coolant system pressure boundary function, because it's actually connected to the reactor vessel or the primary system somehow.

So I'm not disagreeing that that's a safety related function, but that has nothing to do with the operability of the actual pressure instrument that's providing the interlock for operation of this non-safety system. Now, in this particular plant, that non-safety system is classified as RTNSS.

MEMBER SIEBER: Which is really a safety system.

MEMBER STETKAR: Well, no, it's not a safety system. It's a non-safety system.

PARTICIPANT: Important to safety.

MEMBER STETKAR: It's important to safety, but it's not a designated safety system.

So the question is for that particular system and that particular instrumentation, is that instrumentation required to meet --

MEMBER MAYNARD: Is that instrument line safety related?

MEMBER SIEBER: Not required.

MEMBER STETKAR: For pressure retention in the primary system, it is. It must remain intact.

MEMBER MAYNARD: But their definition just says is it safe, right?

MS. ABDULLAHI: Relied up.

MEMBER SHACK: Again, that's assured by designing it through a proper code.

MEMBER STETKAR: That's right. The instrument doesn't have to work to meet that.

MEMBER MAYNARD: But the ability of this reg. guide for considering the consequences of trapped or evolved gases is for safety related sensing lines. It doesn't say safety.

MEMBER STETKAR: But the instrument has to work.

MEMBER MAYNARD: I understand, but this guide says that for safety related instrument sensing lines, even if it's only safety related for pressure boundary retention, the reg. guide the way I read it is saying that you have to consider the effects of evolved gases, of trapped gases.

MEMBER ARMIJO: By that reading, you would --

MEMBER STETKAR: By that reading, that's a stretch.

MEMBER STETKAR: By that reading you cover RTNSS.

MEMBER STETKAR: By that reading --

MEMBER ARMIJO: -- everything connected to the primary pressure boundary.

MEMBER SIEBER: That's not the way they interpret that.

MEMBER STETKAR: it is a matter of interpretation.

MEMBER SIEBER: An architect-engineer would say, just like a coolant pump, it's the pressure boundary that counts.

MEMBER MAYNARD: You would have to address it by the reg. guide and also the industry standard that says it's safety related. You've got to make a decision as to whether you have to deal with evolved gases or not.

VICE CHAIRMAN ABDEL-KHALIK: But if you are having difficulty understanding the scope of this reg. guide, then the people to whom this is meant to provide guidance will have an equal amount of difficulty

MR. KHOI NGUYEN: I think the reg. guide applied to the instrument sensing line, safety related by definition, instrument sensing line. If that pressure boundary or safety related function or not, I think if it's by definition it's classified safety related, is applied to this reg. guide.

MEMBER BROWN: It seems to me a safety related instrument also applies for trying to maintain the plant in a normal configuration in which it's supposed to be as opposed to being someplace where you, because of the inaccuracies, you're not where you're supposed to be.

So I mean, a sensing line is more than just mitigating, more than just shutting it down and maintaining a safe shutdown condition or to prevent or mitigate the consequences of accidents. In other words, you want to make sure your plant is operating where it's supposed to be during normal operations as well.

That doesn't say that explicitly. You just kind of have to read it all into that.

VICE CHAIRMAN ABDEL-KHALIK: I mean, one reading of this would be that any instrument line connected to the primary pressure boundary falls under this reg. guide, any.

MEMBER STETKAR: And some other aligns might be.

VICE CHAIRMAN ABDEL-KHALIK: Right. Regardless of what it's being used for.

MR. KHOI NGUYEN: That is correct.

MEMBER ARMIJO: Can you think of any stuff that wouldn't be connected, that could get into that kind of problem.

MEMBER STETKAR: I would have to think pretty quickly here.

MEMBER RAY: Refueling water level monitor, for example. It has got nothing to do with operating the plant. It's connected to the pressure boundary.

MEMBER STETKAR: Yes, you're right or a cold pressurizer level tap.

MEMBER RAY: But this seems like it doesn't sound like the right conversation.

MR. KHOI NGUYEN: Well, the evolved gas is just one issue of the reg. guide. It is not --

MEMBER ARMIJO: Trace heating issues or --

MR. KHOI NGUYEN: Right. That's main issue involved with the instrument sensing line and the evolved gas was added in this reg. guide, and it's not an error, but we added it as a result of some of the reactor events, but this reg. guide calls for more than the evolved gas.

MEMBER MAYNARD: I'm not concerned about the scope for the existing plant design. This is basically a revision to a reg. guide that's been in used for a long time. What I have a little less confidence in is in trying to figure out whether the new designs, if there's something a little bit odd there.

But as far as the scope for the existing plants and stuff, they've been using this reg. guide all along.

MEMBER STETKAR: Well, the new plants are doing everything that they can to minimize the number of things that they classify as safety related, and they are --

MEMBER MAYNARD: But I'm not sure that this really relieves them from having to take --

MEMBER STETKAR: I'm not sure either because they're very careful about defining. I've seen in some of the DCDs very careful wording that says this instrument line is safety related for a pressure retention function, but the instrument itself is not safety related. I've seen that.

MEMBER MAYNARD: But again, I think the primary concern here is does somebody want to -- are attached to the RCS. Let's kind of go back around here and get -- first of all, do you have anymore to present?

MR. KHOI NGUYEN: That's all I have.

MEMBER MAYNARD: Okay. We'll come back to this item again. I want to go back a little bit to the flashing issue. You know, changing wording in this to clarification, I don't have a real issue with. If we're adding a new concept that hasn't been, then I consider that a significant change. It may have to go back out for comment again. I'm not sure what the process within the NRC would be.

So I think we need to talk about that a little bit and also get the staff's opinion on that, and flashing is a little bit more than just an editorial. Is that adding a new requirement.

VICE CHAIRMAN ABDEL-KHALIK: I think, you know, if that is the case then we should point that out in the letter and say that the staff should evaluate this issue and determine whether or not that should be added and should be considered in reg. Position 4.

MEMBER BANERJEE: Understand this flashing business. It means that the pressure must drop below the saturation pressure.

MEMBER SIEBER: That's right.

MEMBER BANERJEE: In some region.

MEMBER SIEBER: That's right.

MEMBER BANERJEE: And that happens despite of the gravity head.

MEMBER BROWN: Yeah, look at the picture. That's a real situation. That's the way they look, and if you have a fairly rapid transient, you depressurize in that condensing cup and flash and the head goes down, and you get an inaccurate reference.

MEMBER SIEBER: Well, it's loaded with bubbles. So the weight of it is less than it would be if it were solid.

MEMBER BROWN: Bubbles are different. It just depends on where your level of temperature and pressure and saturation temperature occurs.

MEMBER BLEY: John raised a point that came up in the Subcommittee meeting. When we first started talking about evolved gases, we were talking condensable/noncondensable gases. I think by the end they said it also applied to the vapor itself. If it does, it covers flashing.

MEMBER SHACK: Evolved gas is steam.

MEMBER SIEBER: It doesn't say this.

MEMBER BLEY: That was sort of my interpretation.

MEMBER SHACK: But I thought that's where the discussion ended up a couple of days ago in our meeting.

MEMBER BANERJEE: That's not a precise way to say it.

MEMBER SHACK: It's not a precise way.

MEMBER BANERJEE: You need to be more precise.

MEMBER SIEBER: Well, the reg. guide doesn't say it, and that's what we're writing about. It says noncondensable.

MEMBER ARMIJO: I thought the evolved gases were supposed to be sort of dissolved gases and resulting from chemical reaction. Something like that was in there.

MR. KHOI NGUYEN: That's in the glossary section.

(Simultaneous conversation.)

MEMBER SIEBER: Steam is not a dissolved gas.

MEMBER BANERJEE: It's a vapor. It's not a gas.

MEMBER SHACK: The question, evolved gas is necessarily a dissolved gas.

MEMBER SIEBER: Yes.

(Simultaneous conversation.)

MEMBER ARMIJO: Maybe our letter just really has to say something. Either that or we say flashing treated properly used somewhere else.

VICE CHAIRMAN ABDEL-KHALIK: The term "evolved gases" as defined in the glossary does not include flashing.

(Simultaneous conversation.)

MEMBER ARMIJO: Some sort of chemical reaction starts fizzing out of something or just pure dissolved gases.

MEMBER SIEBER: It could be absorbed. It would be change in solubility.

(Simultaneous conversation.)

MEMBER MAYNARD: But let me ask the staff on the timing of this. Is there any specific deadline, like that has to be out before some plant -- what's the deadline? What's the urgency on this? Is there any deadlines that we're coming up to on issuance of this?

MR. KHOI NGUYEN: I'm not aware of any urgency on issuing this reg. guide.

MEMBER MAYNARD: Okay. I'd like to have some of your thoughts on the flashing aspect. You've heard the discussion. We're talking about the new concept could be considered significant change to this. Do you have any views on that? Are we wrong or are we --

MR. KHOI NGUYEN: Well, I don't know. The flashing having covered by an other documents, any reg. guides, any regulation?

MEMBER SIEBER: I think Charlie would agree with me that an instrument designer, that's one of the fundamental things for all of the instruments, and you try to get enough distance away from the vessels that you're measuring the level on so that you don't get radiated heat in there, that the reference leg is much lower in temperature, and then you can calculate how much pressure drop will cause the reference leg to flash, and good instrument designers will do that, but if it isn't written down that you do it, you know, you could get an instrument designer that got all seasons.

MEMBER MAYNARD: Well, it is something that is incorporated in the design, but I know we have certainly talked about it in the industry. I think the question is is it needed in this reg. guide.

MEMBER SIEBER: Or is it covered somewhere else.

MEMBER BLEY: And one place it is not

covered is in the referenced ANSI standard. It isn't mentioned.

MEMBER SIEBER: And the question is should it be covered, and I think it should. I think you should at least say it.

MEMBER STETKAR: But it might be very easy to comply with because it's normal practice, but if you don't say it --

MEMBER SIEBER: Yes, right. Everything in the --

PARTICIPANT: This is not a sensing line issue.

MEMBER SIEBER: -- pressure vessel is normal practice, but until you write it down it's not code.

MEMBER BLEY: You know, there are two things on it. It isn't really a sensing line issue. It's the design of the reference leg, not the sensing line. This is about sensing lines from the standards. So there's somewhere, there must be somewhere else where the instrument design is --

MEMBER SIEBER: The reference leg is a sensing line.

MEMBER BLEY: Yes, but that is not the sensing line, and this is a reg. guide on sensing line. The referenced ANSI standard is --

MEMBER BROWN: Oh, no, no, no.

MEMBER BLEY: The referenced ANSI standard is on sensing lines. There's probably another reg. guide and certainly another ANSI standard that tells you how to design that instrument.

MEMBER SIEBER: The reference leg is a sensing line.

PARTICIPANT: I think you are straining this one too fine.

MEMBER BLEY: I don't think so. I'd bet a lot that there is a standard on it.

MEMBER SIEBER: I'll bet you 50 cents.

(Laughter.)

VICE CHAIRMAN ABDEL-KHALIK: I mean, if we're talking about noncondensable gas accumulation in the reference leg, then you know --

MEMBER BLEY: Of the head.

VICE CHAIRMAN ABDEL-KHALIK: Right. So it's included.

MEMBER MAYNARD: There are other requirements. This is about the design and installation of the instrument lines. There's other regulations that require that the indications that you use would have to be --

(Simultaneous conversation.)

MR. KHOI NGUYEN: The main reason -- I'm sorry.

MEMBER SIEBER: So why do we need to talk about noncondensables here?

MR. KHOI NGUYEN: Yeah, the main reason we want to add the noncondensable gas here, because we have several --

MEMBER SIEBER: It's op. experience.

MR. KHOI NGUYEN: -- events and we have several NRC information notices putting out there, but no formal writing or information to provide.

MEMBER MAYNARD: Okay. The standard does address that for the evolved gases. It doesn't really address flashing, but it does address that you have to design and consider evolved gases.

MR. KHOI NGUYEN: Right. It recognized the problem and warning that the industry should consider the issue, but they didn't mention about flashing.

MEMBER ARMIJO: Silent on flashing.

MEMBER SIEBER: Actually the BWR Owners Group fix helps the flashing situation, injecting cold CRD water into the bottom of that leg, but that's not the reason why they put it in. They put it in for noncondensable.

MEMBER RAY: You know, this says here operational events have occurred in which evolved gases and instrument lines have affected measuring water levels in operating nuclear power plants. That would imply we're not talking about flashing.

But then it says the NRC issued information notice umpty-ump to alert licensees to potential inaccuracies in water level indications during and after rapid depressurization events, which makes it sound like we are talking about flashing.

MEMBER SIEBER: All we have to do is read it and see.

MEMBER RAY: I am reading it.

MEMBER SIEBER: No, but you have to read the information notice.

MEMBER RAY: I understand, but that's what they said about it here anyway.

MEMBER SIEBER: Yes, but what doesn't help. That's just a reference.

MEMBER RAY: Well, my point, Jack, was that they seem to be mixing up noncondensable gases with rapid depressurization events.

VICE CHAIRMAN ABDEL-KHALIK: The noncondensable gases come about as a result of rapid depressurization.

MEMBER RAY: Well, it could be, but it can also -- I don't know how you can separate an inaccuracy due to rapid depressurization because noncondensable gases are evolved from flashing. I mean, it doesn't really seem to go hand in glove to me.

MEMBER ARMIJO: I don't know of any chemical reaction in at least a boiler that happens when you depressurize.

MEMBER SIEBER: You have dissolved oxygen. You have --

MEMBER ARMIJO: No, I'm talking about the other part, not dissolved gas. I'm talking just chemical. The glossary says four chemical reactions, right? What chemical reactions occur when you depressurize a PWR?

MEMBER SIEBER: Radiolysis.

MEMBER ARMIJO: That's not a chemical reaction.

MEMBER BANERJEE: Well, it is a chemical reaction.

MEMBER SIEBER: Sure it is.

MEMBER MAYNARD: Let's see where we're at with this. One of the things that is causing a lot of the discussion is the inclusion of the evolved noncondensable gases in this reg. guide, and that wasn't specifically talked about before. Now, one of the public comments that you guys did not incorporate was that perhaps this should be separated out and there should be a different reg guide for that aspect of it.

You know, just taking a look at it, it sounds to me like if we're going to include the noncondensable gases in this, it sounds like the Committee is going to want more discussion on that. I'm getting the sense that we wouldn't necessarily be comfortable with issuing it the way it is with all the discussion that we've had.

MEMBER SIEBER: You're going to have to postpone your retirement.

(Laughter.)

MEMBER MAYNARD: That's not going to happen.

You know, there's a couple options. One, we could bring this back. We could -- there was all this discussion. You know, have an additional Subcommittee meeting and then bring it back again.

We could separate out the noncondensable gases and just endorse the later version of the reg.

guide and recommend that a separate guidance be developed on the noncondensable gases, on the evolved gases.

I'm not sure we're getting anyplace. I don't here a discussion that's kind of bringing us to a consensus that what's here is something that we would be comfortable with. I don't know.

MEMBER SIEBER: What would the staff like to do?

MEMBER ARMIJO: I got the message the staff's intent was that this reg. guide would address all the issues related to instrument sensing line inaccuracies, whether it's trace heating, evolved gases, but they didn't mention flashing. So if it's intended to be complete, it should include, address the flashing issue. It should have a little bit of discussion in the reg. guide if that's the intention.

If it's adequately covered in some other reg. guide, which I don't know, maybe it's okay, but right now it seems --

MEMBER SIEBER: Actually, what Otto said leads us to the answer. The question is: what does the staff want to do?

Noncondensable gases is an issue. Flashing is an issue. Do you want it all on one reg.

guide? Do you want to work on another reg. guide, or can you find in the regulation where flashing is addressed?

So there's three options. The staff really should be telling us how they want to deal with it, and we should fashion our recommendation to accommodate that. And lacking a staff response, we'd say put flashing into this one.

MR. SYDNOR: My name is Russ Sydnor. I'm the Branch Chief for the Digital I&C Branch in the Office of Research.

And I was at the Subcommittee also. Actually this is sort of a new issue that didn't really come up at the subcommittee, but I think the intent is to address any issue that affects instrument accuracy as a result of rapid depressurization no matter what the phenomenon is.

So I think there's wording clarifications that we can work on for the reg. guide, but I think that's the intent here, and there is not enough -- we went through all of the information notices, bulletins, generic letters. They primarily describe the events. They did not produce designs to resolve a universal set of events for this. The closest that came to that was the BWR Owners Group came up with a design using the cRD system.

But even that had problems after they installed it. So there were further information notices dealing with the design problems of the fix. So the purpose of the reg. guide wasn't to specify design criteria and as really almost an infinite set of that depending on how you design the systems, but I think it is important to put a position in here. It sounds like it needs some careful clarification.

I think flashing was a good addition. We can go back and read the information notices again. I'm not sure that some of those didn't actually talk about that.

MEMBER STETKAR: Well, in the glossary, define what an evolved gas is.

MR. SYDNOR: That's almost a dictionary definition in the glossary.

MEMBER SIEBER: Let me make a comment on what you said from an operator's viewpoint. The operator looking at the instrument response can't tell the difference between noncondensable gases coming out and flashing, except if it's flashing that will recover after a few minutes or an hour, however long it takes to cool the reference leg back down.

MEMBER BROWN: Well, it may well be that

noncondensables, if they depending on the -- they may vent out after a period.

MEMBER SIEBER: Well, they may go into the --

MEMBER BROWN: They may go back into the system itself.

MEMBER BLEY: That is why the backfill was to clear the noncondensables and make sure they had a path.

MEMBER SIEBER: And it also keeps it cold.

MEMBER SHACK: I mean, it could be that the designers have been successful dealing with the flashing. So there is no problems with it.

MEMBER BROWN: Yeah, I think, Bill, that's probably more the case.

MEMBER SIEBER: Then they can say that and say, "I'm perfect already."

MEMBER BROWN: If you read what they said --

MEMBER ARMIJO: You can mention it and it's no problem.

MEMBER BROWN: This is based on experience, and I think what Bill said is more closer to the truth because, you know, I go back 40 years with the issue of flashing and need for condensing pot and keep the reference leg sub-cooled, and all of that has been known forever.

But the problem that is discussed here repeatedly is noncondensable gases, and I think they just got stuck on that and didn't --

MEMBER BLEY: Well, the events. The statement that it should be sort of dealt with here is probably --

MEMBER SIEBER: I sort of agree with the staff suggestion that they work the words a little bit, and that would solve the problem for me.

VICE CHAIRMAN ABDEL-KHALIK: Why don't we, as a part of any recommendation that we would make in our letter, recommend that they expand the proposed regulatory Position 4 to address the effect of flashing as a result of rapid depressurization?

MEMBER BROWN: Because it is indistinguishable in terms of its potential and effect from noncondensable gases.

MR. KHOI NGUYEN: Now, if we want to add flashing into this reg. guide, I don't think we just simply to add the wording in the Position 4. We need to add a paragraph in the discussion section because if we don't introduce it and we said --

MEMBER MAYNARD: Well, I'm feeling

uncomfortable with just adding a word.

MR. KHOI NGUYEN: I understand.

MEMBER MAYNARD: I'm trying to write something on the fly here, and so I'm kind of looking at what's the next step. I believe the staff needs to go back after this discussion and give it some thought, see where the right place to put this is, and then come back.

I feel uncomfortable with us endorsing something as saying do so, modify it, and then issue it.

MEMBER BANERJEE: But, Otto, we do write letters where we endorse something conditional on fixing something.

MEMBER STETKAR: Well, but I think Otto has got another point.

MEMBER MAYNARD: Typically, see, we were close to doing that on this. They had proposed some additional wording. Typically we have seen what they plan to do, and we put that conditional incorporating, you know, what they discussed or whatever, and we don't really have something here, I mean, a proposed wording or anything.

MEMBER BANERJEE: Yeah. What you're saying is we would need to review that again.

MEMBER MAYNARD: I believe so.

MEMBER SHACK: Well, I am more concerned about your other concern, that you might have to send this out to comment again.

MEMBER MAYNARD: Yeah, because I do think this is a substantial change, even though I kind of believe with Harold that this is --

MEMBER RAY: It depends on the size of the transient and whether you want to keep the reference leg from flashing under all conditions. I mean, I can think of reasons why people would be concerned about just sticking --

MEMBER SIEBER: Well, it would take a big change to get it to fly.

MEMBER MAYNARD: And it certainly depends on how it ends up getting worded in the reg. guide as to whether this becomes something that's really essentially a new requirement or is essentially what's already been done. I think there are some potential legal issues as to what has to be done and stuff there.

No, I agree, Sanjoy. We have a number of cases of approve something contingent upon a change, but it has usually been a change that we've already been briefed on and agreed. We've only agreed with the concept here, but not really what the specifics are, and without knowing what the impact is.

MEMBER BANERJEE: Well, it could be also that industry is already doing this, but as we haven't done a due diligence on what they're doing right now. So maybe what you're saying is the staff should go back, see what industry is doing, see if there's anything that needs to be added. Maybe there is nothing that needs to be added.

MEMBER SIEBER: Well --

MEMBER BANERJEE: Maybe they're already taking care of these problems.

MEMBER SIEBER: -- if they're taking care of it, there's no harm in saying you should --

MEMBER RAY: Take care of it.

MEMBER MAYNARD: Well, but it depends on how you say to take care of it. If you say to take care of it the way you've been doing it, that's one thing, but if you say take care of it in this way and that's different --

(Simultaneous conversation.)

MEMBER SIEBER: I wouldn't want to --

MEMBER MAYNARD: Unintended consequences is kind of what I--

MEMBER SIEBER: I wouldn't want to come

out with a position that says you shall have zero flashing because I think that is not going to really work, but I think you should be within the error band for the safety analysis you're doing that relies on that signal.

MEMBER BROWN: You can do that by the design of a condensing process, a flashing program.

MEMBER SIEBER: You can get close.

MEMBER BROWN: Within the band is what I'm talking about.

MEMBER SIEBER: Right.

MEMBER MAYNARD: Here's kind of where I'm standing on this right now.

MEMBER SIEBER: It's standard size and distance and temperature.

MEMBER MAYNARD: I would recommend that the staff go back, take a look at this, and I think either have another Subcommittee meeting or another full Committee meeting, come back with some proposed wording.

PARTICIPANT: I wouldn't think we need a Subcommittee.

CHAIRMAN BONACA: But do we need to write a brief letter outlining this issue so that --

MEMBER MAYNARD: My recommendation would

be no, we wait until they come back with something proposed, but I'm kind of biased.

(Laughter.)

MEMBER MAYNARD: I have a reason for that.

VICE CHAIRMAN ABDEL-KHALIK: We need to document this by saying this reg. guide should not be issued until such-and-such issue has been addressed.

MEMBER SIEBER: Until the wording is changed.

MEMBER BROWN: Until these issues are resolved.

CHAIRMAN BONACA: It would have to be a comprehensive letter at this point. Just a hold in the statement that says, you know, we could not proceed further. We don't believe that the reg. guide should be issued until these issues are clarified.

MEMBER MAYNARD: Now, we talked about a couple of things. Is it just adding the flashing --

MEMBER ARMIJO: I have one more.

MEMBER MAYNARD: -- or do we still have an issue with the scope?

MEMBER STETKAR: I am still concerned about the scope only because I've read too many things that are very carefully worded to say that this instrument line is safety related for pressure retention, but the instrument is not safety related, and the question is what is the intent of this reg. guide. If the intent, recognizing the new reactor designs with RTNSS systems, if the intent is still to focus solely on the operability of only safety related instrumentation, then we should be aware of that.

If the intent is broader in the sense of the words that are quoted from GDC-13 to insure the operability of instrumentation that's required to monitor plant status and cope with a broad range of abnormal events, then it can't be necessarily related to only safety related instrumentation.

MEMBER ARMIJO: But you can read it that way though, John. You can read it that way, the current wording.

MEMBER STETKAR: That it's broader?

MEMBER ARMIJO: Yeah.

MEMBER STETKAR: And I can also read it very narrowly.

MEMBER MAYNARD: I think you can have a statement in there that states just to consider --

MEMBER STETKAR: And I don't know the intent.

MEMBER MAYNARD: -- basically you're taking into account that a number of the newer plants are relying less on safety systems and more on RTNSS systems, and make sure that there's not something left out of scope that would be necessary in this.

MEMBER BLEY: Except in a few of the new designs, one that I can think of, the exact treatment for RTNSS I don't think has all been worked out. So can you guys speak to whether this was intended to talk to RTNSS?

VICE CHAIRMAN ABDEL-KHALIK: No, we can't.

MR. SYDNOR: No, I can't.

VICE CHAIRMAN ABDEL-KHALIK: So a clarification would be necessary.

MEMBER MAYNARD: So it would basically be that and the flashing.

MEMBER ARMIJO: I just want to add another thing. I don't understand in the glossary they talk about evolved gases being the stuff coming out of solution. I understand that, but I don't know why what chemical reaction is --

MEMBER SIEBER: It's dissolved gas. Any time you have water --

MEMBER ARMIJO: But I understand. That's a solubility issue. I'm talking about chemical reaction. Should chemical reaction --

(Simultaneous conversation.)

MEMBER ARMIJO: Maybe it should be taken out of this glossary then.

MEMBER MAYNARD: Does it hurt having it in there?

MEMBER ARMIJO: Yeah, I think it is because what chemical reaction are you supposed to work on?

MEMBER BANERJEE: Radiolysis.

MEMBER ARMIJO: Then say radiolysis. Don't say chemical reaction.

MEMBER BANERJEE: Well, they might just be covering their --

MEMBER ARMIJO: I don't know how radiolysis changes when you depressurize.

MEMBER BANERJEE: Radiolysis is a chemical reaction, and there could be something which is beyond radiolysis.

MEMBER ARMIJO: Like what?

MEMBER BANERJEE: I can't think of it.

(Laughter.)

MEMBER ARMIJO: I know dissolved gases. That I can understand.

MEMBER BLEY: Maybe they're covering themselves for the future in case we add something.

MEMBER SIEBER: What chemical did they add to BWR boiler water?

MEMBER ARMIJO: I'll tell you if you depressurize a boiler it doesn't start --

MEMBER SIEBER: Hopefully nothing.

(Simultaneous conversation.)

MEMBER MAYNARD: I think the main things we need to focus on here is on the scope of the RTNSS and also on the flashing, getting that added in in the proper way there. I think the staff can consider comments on the definition there, and we can move forward.

Does anybody have any other items or discussion here?

Let me go back to the staff and see if there's anything. We've confused ourselves. Have we confused you any?

MR. SYDNOR: No, I think we understand the two key issues here. Just real quickly, I believe we added the definition, and it is pretty much a dictionary definition for evolved gas due to a public comment on what an evolved gas was, if I recall right.

MEMBER ARMIJO: But it shouldn't raise an issue that doesn't exist. If there is a chemical reaction, you know, it's possible in a --

MR. SYDNOR: On the other hand, one could argue that the NRC doesn't have the authority to change dictionary definitions.

MEMBER MAYNARD: Well, also you don't know what new designs and new processes may come up. Personally I don't have a problem with it being there. I don't see where it hurts anything. If you can't think of any chemical reaction, fine, but in the future who knows what we may be using in some of these reactors?

MEMBER BROWN: Change the word "evolved" to "dissolved," and take out the word "chemical."

MEMBER ARMIJO: Dissolved gases.

MR. KHOI NGUYEN: I have a question.

MEMBER MAYNARD: Go ahead.

MR. KHOI NGUYEN: I have a question for the Committee. I don't have the basis to know if there's other documentation or reg. guides or any rules to cover the flashing, but if I find one, is that okay to reference to it?

MEMBER MAYNARD: Oh, yes.

MR. KHOI NGUYEN: And then we don't have to go back for public comments. That's the ways way.

MEMBER MAYNARD: First of all, we're not saying you have to go out for public comment. We're saying that that may be a consequence of some of the things. That's up to the staff to figure out and work out whether you have to do that or don't have to do that.

MR. KHOI NGUYEN: Because I think adding the flashing is expanding the scope, and I don't know if we need to send it out again for public comments.

MEMBER MAYNARD: And, again, that's for the staff to decide whether they have to do that or not, not for us. I think if you find that there's another requirement and can just reference that requirement in this reg. guide, I think the Committee would be satisfied with that.

MEMBER BANERJEE: Yeah, it could well be that there is something which tells you how to deal with flashing.

MEMBER ARMIJO: That's my guess.

MEMBER BANERJEE: Yeah. If there is, then just reference it.

MEMBER MAYNARD: So again, going back to if there are several things out there that address it, that's fine. The intent of this reg. guide was to address any inaccuracies due to --

(Simultaneous conversation.)

MEMBER MAYNARD: -- gases that are formed. Then it's good to go ahead and identify those and reference that works someplace else.

Okay. Anything else from the staff?

(No response.)

MEMBER MAYNARD: Anything else from the members?

MEMBER BANERJEE: Are we writing a letter or not?

MEMBER MAYNARD: We will discuss that again, I think, later. I do have a boilerplate part of a letter put together. We can take a look and see whether it adds any value to send it out with adding a few things or whether we have the staff come back to us.

VICE CHAIRMAN ABDEL-KHALIK: Well, we have specific recommendations that this reg. guide should not be issued until these two issues that we've identified are addressed.

MEMBER MAYNARD: Yes, all right. I think we're probably going to write one again. I always hold out hope.

(Laughter.)

MEMBER BANERJEE: We want a final letter from your group.

PARTICIPANT: They want to torture you, is what they want to do.

(Laughter.)

MEMBER MAYNARD: John, did you have something? Okay.

With that I'm going to quickly turn it back to you, Mr. Chairman.

CHAIRMAN BONACA: All right. I think we are ahead of time again, which is great, and we are due for a break, if you would like that, and then we can come back and have one subcommittee report. That's the one on the AP-1000.

MEMBER BROWN: A Subcommittee report?

CHAIRMAN BONACA: Yes. We'll do it after the break.

MEMBER BROWN: All right.

CHAIRMAN BONACA: So let's take a break until 5:05.

We will close the record.

(Whereupon, at 4:42 p.m., the Committee meeting was adjourned.)

Prairie Island Nuclear Generating Plant

ACRS License Renewal Meeting

December 3, 2009

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Introductions

- Mark Schimmel – Site Vice President
- Gene Eckholt – License Renewal Project Manager
- Steve Skoyen – Engineering Programs Manager
- License Renewal Project Team and Subject Matter Experts

Agenda

- Site Description
- ACRS LR Subcommittee Follow-Up Items
- Questions

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Site Description

- Plant Owner, License Holder and Operator
  - Northern States Power Company – Minnesota
  - Subsidiary of Xcel Energy
- Location
  - SE of Minneapolis-Saint Paul, MN
  - On Mississippi River

Site Description

- Construction Permits Issued - June 1968
- Operating Licenses
  - Unit 1
    - Issued August 1973
    - Expires August 2013
  - Unit 2
    - Issued October 1974
    - Expires October 2014
- LRA Submitted – April 2008

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Site Description

- Two 2 - Loop PWR Units
  - 1650 MW_t
  - 575 MW_e (Gross) per Unit
- Westinghouse - NSSS
- Pioneer Service & Engineering - Architect/Engineer
- Once-Through Cooling Supplemented with Four Forced Draft Cooling Towers (Seasonal)
- Ultimate Heat Sink is Mississippi River via Cooling Water System

Site Description

- **Dual Containment Design**
  - **Steel Containment Vessel Within Limited Leakage Concrete Shield Building (5 Foot Annulus)**
  - **Steel Containment Vessel**
    - **Provides Primary Containment**
    - **Lower Head Encased in Concrete**
    - **1-1/2 inch Thick Bottom Head, 1-1/2 inch Thick Shell, 3/4 inch Thick Top Head**
    - **3-1/2 inch Thick at ECCS Sump Penetrations**

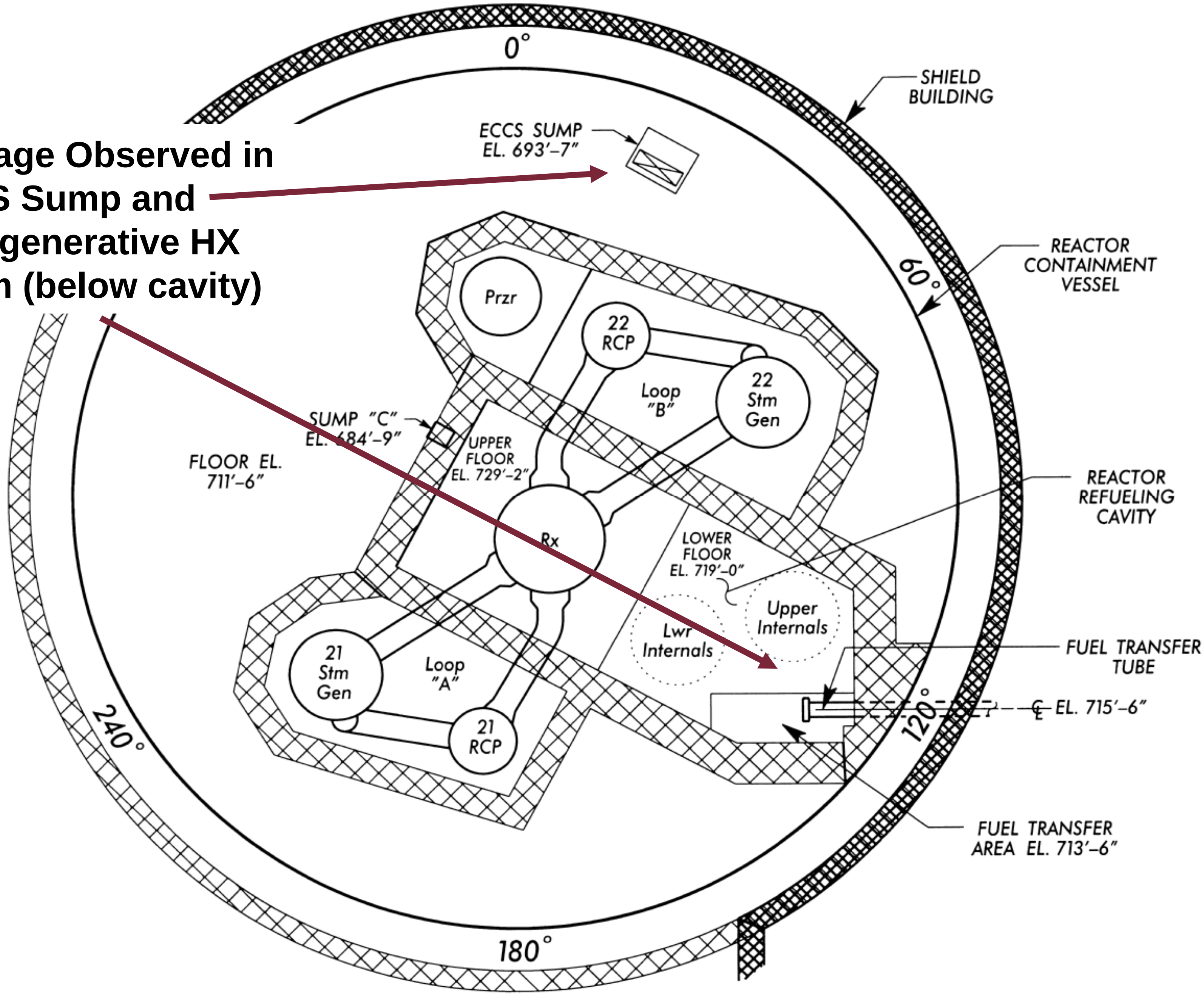
ACRS LR Subcommittee Follow-Up Items

- **Refueling Cavity Leakage**
- **Condensate Storage Tank Examinations**
- **Underground Medium Voltage Cables**
  - Manhole Inspection Interval
  - Impact of Freeze/Thaw Conditions

Refueling Cavity Leakage
Leakage History

- Intermittent Refueling Cavity Leakage in Both Units Since Late 1980s
- Estimated Leak Rate of 1-2 Gallons per Hour
- Observed in ECCS Sump and Regenerative Heat Exchanger Room
- Sealing Methods Used to Mitigate Leakage Were not Consistently Effective
- Root Cause Performed in Early 2009 to Identify Permanent Solution

Leakage Observed in ECCS Sump and in Regenerative HX Room (below cavity)



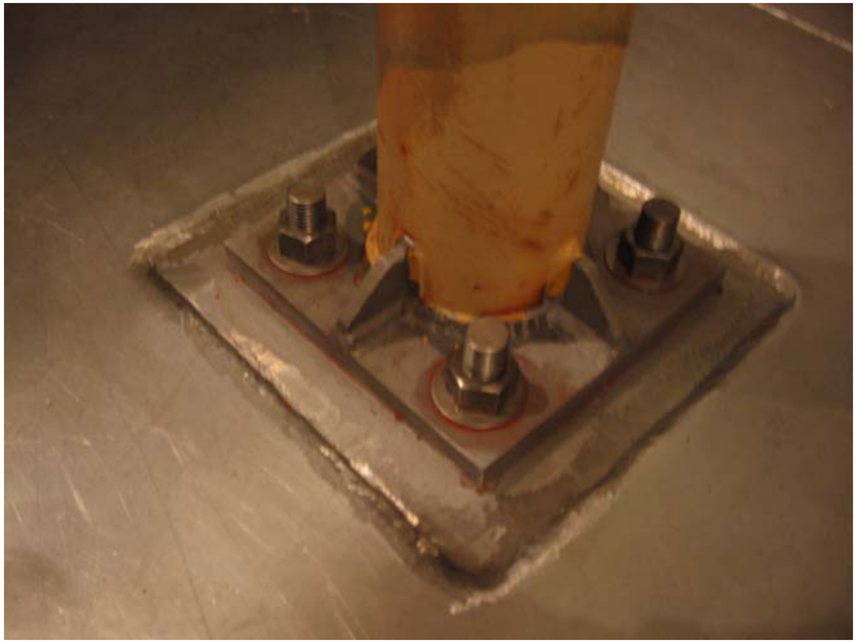
Containment Elevation

Refueling Cavity Leakage Root Cause Evaluation

- **Root Cause Evaluation Completed in April 2009**
- **Sources of Leakage were Determined to be Floor Embedment Plates for Reactor Vessel Internals Stands and Rod Control Cluster Assembly (RCCA) Change Fixture**
- **Exposure of Containment Vessel and Structures to Refueling Cavity Water Has Not Had an Adverse Impact on Their Ability to Meet Design Requirements**

Refueling Cavity Leakage Root Cause Evaluation

Typical Reactor Vessel Internals Stand Support



Typical RCCA Change Fixture Support

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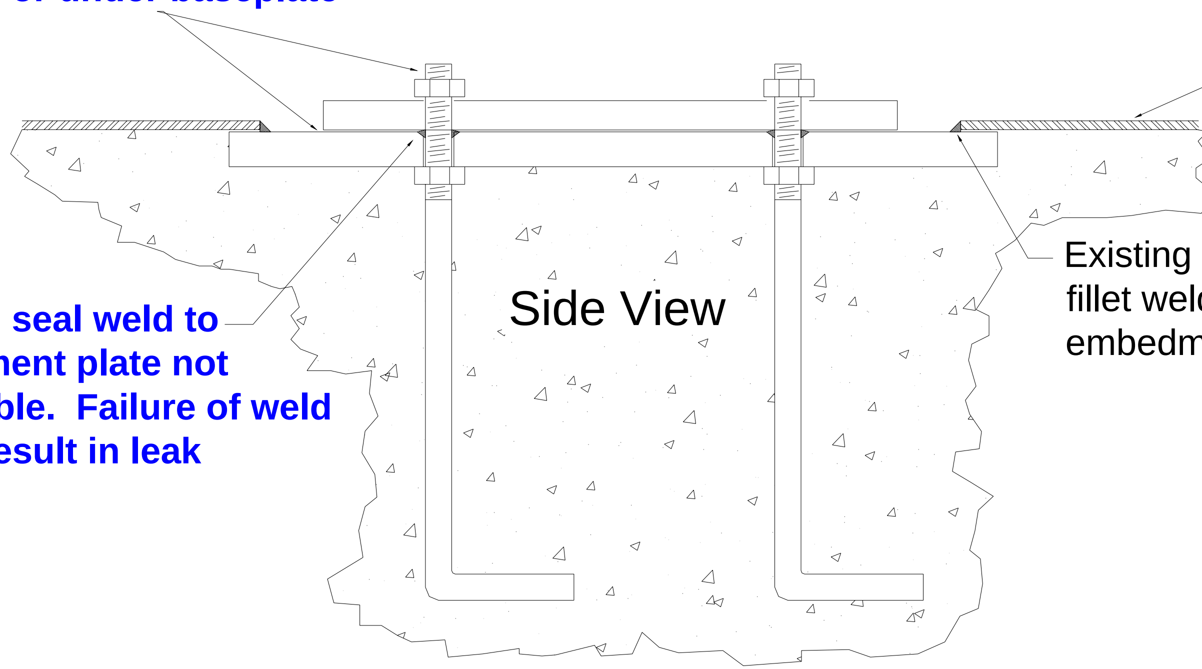
Refueling Cavity Leakage
Root Cause Evaluation

Original Embedment Plate Configuration

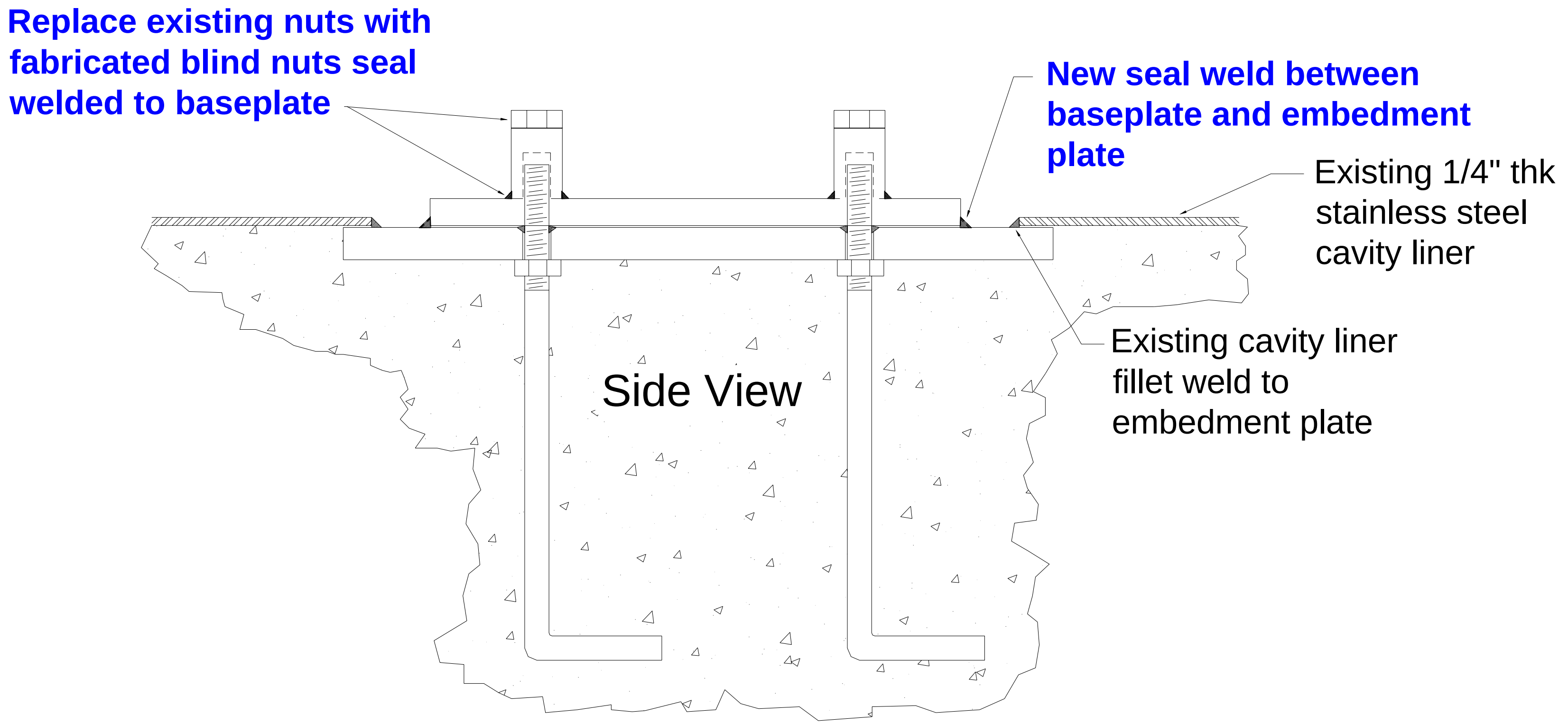


Refueling Cavity Leakage
Fall 2009 Unit 1 Repairs

- **Reactor Vessel Internals Stands and RCCA Change Fixture Embedment Plates Repaired**
  - **Existing Nuts Removed**
  - **Replaced with Blind Nuts**
  - **Blind Nuts Seal Welded to Baseplate**
  - **Seal Weld Applied Between Baseplate and Embedment Plate**
  - **Welds Examined by NDE**

Refueling Cavity Leakage
Fall 2009 Unit 1 Repairs

Repaired Embedment Plate Configuration



Refueling Cavity Leakage
Fall 2009 Unit 1 Repairs

Refueling Cavity Leakage
Fall 2009 Unit 1 Repair Results

- **Repair of Floor Embedment Plates Eliminated that Leakage Source**
- **ECCS Sump**
  - **No Evidence of Leakage**
- **Minor Leakage Observed on Ceiling of Regenerative Heat Exchanger Room**
  - **Appeared After Cavity Flooded 14 Days**
  - **Estimated to be 0.05 Gallons per Hour**

Containment Elevation

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Refueling Cavity Leakage
Fall 2009 Unit 1 Repair Results

- **No Evidence Leakage Reached Containment Vessel**
  - **No Leakage Through Wall in ECCS Sump**
  - **No Leakage at Intersection of Transfer Tube and Containment Vessel Concrete**
  - **Minor Leakage Observed in Regenerative Heat Exchanger Room**

Containment
Elevation

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Refueling Cavity Leakage
Fall 2009 Unit 1 Testing and Inspection

- **Original Scope of Testing and Inspection**
  - **Vacuum Box Testing of Refueling Cavity Liner Plate Seam Welds - No Leakage Identified**
  - **NDE of Fuel Transfer Tube Welds – No Indications**
- **Expanded Inspections in Response to Remaining Leakage**
  - **NDE of Liner to Floor Embedment Plate Fillet Welds**
    - **One Porosity Indication**
    - **Will be Repaired During Next Unit 1 Refueling Outage**

Refueling Cavity Leakage
Evaluation of Remaining Unit 1 Leakage

- **Evaluation of Source of Remaining Unit 1 Leakage**
  - **RCCA Guide Box Wall Embedment Plates**
    - **Design Similar to Floor Embedment Plates**
    - **Will be Repaired During Next Unit 1 and 2 Refueling Outages**
  - **Evaluation of Other Potential Leakage Sources**
    - **Will Identify any Additional Inspections and Repairs Prior to Next Unit 1 and Unit 2 Refueling Outages**

Refueling Cavity Leakage
2010 Unit 2 Corrective Actions

- **Repair of Reactor Vessel Internals Stands and RCCA Change Fixture Floor Embedment Plates**
- **Repair of RCCA Guide Box Wall Embedment Plates**
- **NDE of Fuel Transfer Tube Welds**
- **Vacuum Box Testing of Refueling Cavity Liner Plate Seam Welds**
- **NDE of Liner to Floor Embedment Plate Fillet Welds**
- **Other Inspections and Repairs Resulting From Evaluation of 2009 Unit 1 Leakage**

Refueling Cavity Leakage
2011 Unit 1 Corrective Actions

- **Repair of RCCA Guide Box Wall Embedment Plates**
- **Repair of Liner to Floor Embedment Plate Fillet Weld Porosity Indication**
- **Other Inspections and Repairs Resulting From Evaluation of 2009 Unit 1 and 2010 Unit 2 Repair Results**

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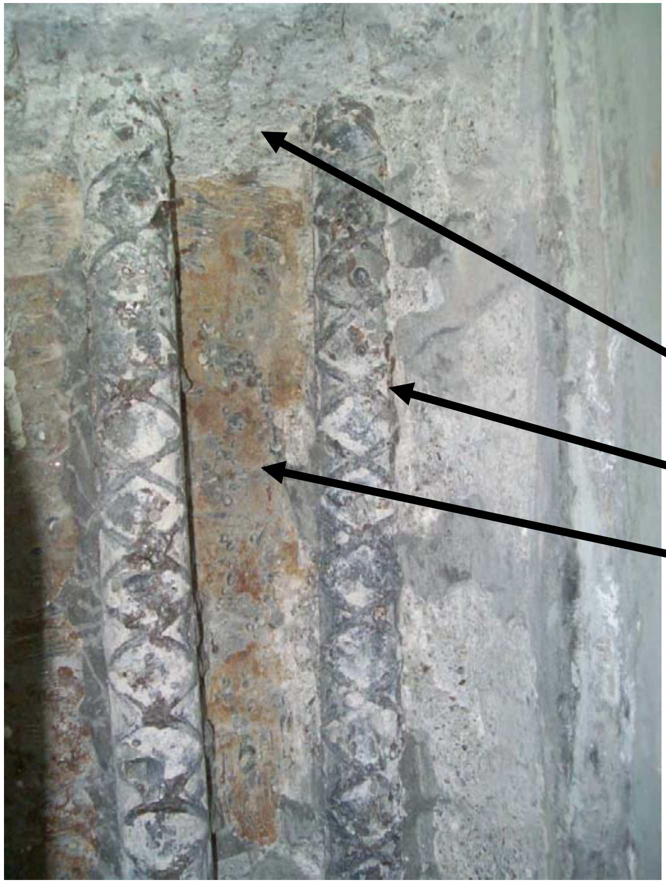
Refueling Cavity Leakage Monitoring and Assessment

- **Ultrasonic and Visual Examinations of Containment Vessel Through ECCS Sump Wall**
  - **Unit 1 and 2 (Prior to 2009)**
    - **Grout Removed**
    - **Wall Thickness at or Above ASTM Specifications**
    - **No Corrosion of Containment Vessel**
  - **Unit 1 (Fall 2009)**
    - **Grout Removed**
    - **Wall Thickness at or Above ASTM Specifications**
    - **No Corrosion of Rebar or Containment Vessel**

Sump Section

Containment Elevation

Refueling Cavity Leakage Monitoring and Assessment



Unit 1 ECCS Sump

Fall 2009

- **Grout not Degraded**
- **Ribs on Rebar Intact**
- **Containment Vessel**
- **No Wet Areas or Leakage**

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Refueling Cavity Leakage Monitoring and Assessment

- **Ultrasonic Examination of the Containment Vessel from the Annulus**
  - **Unit 2 (2008) and Unit 1 (2009)**
  - **Examined Areas:**
    - **From Transfer Tube Toward ECCS Sump**
    - **Above and Behind ECCS Sump**
- **Wall Thickness at or Above ASTM Specifications**

Annulus Photo

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Refueling Cavity Leakage Monitoring and Assessment – Commitments

- **Commitments for Next Refueling Outage in Each Unit Following Embedment Plate Repairs**
  - **Removal of Concrete from Sump Below Reactor Vessel to Expose Containment Vessel**
    - **Inspect (VT and UT) Containment Vessel**
    - **Assessment of Exposed Concrete**
    - **Petrographic Examination of Removed Concrete**
  - **Removal of Concrete Sample Wetted by Borated Water Leakage from Refueling Cavity**
    - **Concrete will be Tested For Compression Strength and will Undergo Petrographic Examination**

Refueling Cavity Leakage Monitoring and Assessment – Commitments

- **Commitment for Next Two Consecutive Refueling Outages in Each Unit Following Embedment Plate Repairs**
  - **Monitor Areas Previously Exhibiting Leakage to Confirm That Leakage has not Recurred**

Refueling Cavity Leakage
Long Term Aging Management

- **Continue to Manage Aging of the Containment Structures and Vessel Using the Structures Monitoring Program and ASME Section XI, Subsection IWE Program**
- **Utilize Corrective Action Program for Evaluation and Correction of New Issues**

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Refueling Cavity Leakage
Evaluation of Potential Degradation

- **The Potential for Degradation of the Steel Containment Vessel and Reinforced Concrete (Concrete/Rebar) was Evaluated**
- **Evaluation Concluded:**
  - **Any Potential Corrosion of the Containment Vessel Behind Concrete in Areas Wetted by Refueling Cavity Water Would be Minor**
  - **No Significant Effect on Reinforced Concrete That Has Been Wetted by Refueling Cavity Water**

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Refueling Cavity Leakage

- **In Summary,**
  - **No Degradation Found to Date**
  - **Evaluation of Potential Degradation Indicates Low Safety Significance**
  - **Committed to Eliminate Refueling Cavity Leakage**

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ACRS LR Subcommittee Follow-Up Items

Condensate Storage Tank Examinations

Condensate Storage Tank Examinations

- Aboveground Steel Tanks Program Included UT Inspection of the Bottom of 1 of the 3 Condensate Storage Tanks Prior to PEO
- ACRS LR Subcommittee Questioned Whether an Inspection of Only 1 Tank Would Assure Acceptability of all 3 Tanks
- LRA Change Submitted on August 7, 2009 Which Revised the Aboveground Steel Tanks Program to Include UT Inspection of the Bottom of all 3 Condensate Storage Tanks Prior to PEO

ACRS LR Subcommittee Follow-Up Items

Underground Medium Voltage Cables

Manhole Inspection Interval

Impact of Freeze/Thaw Conditions

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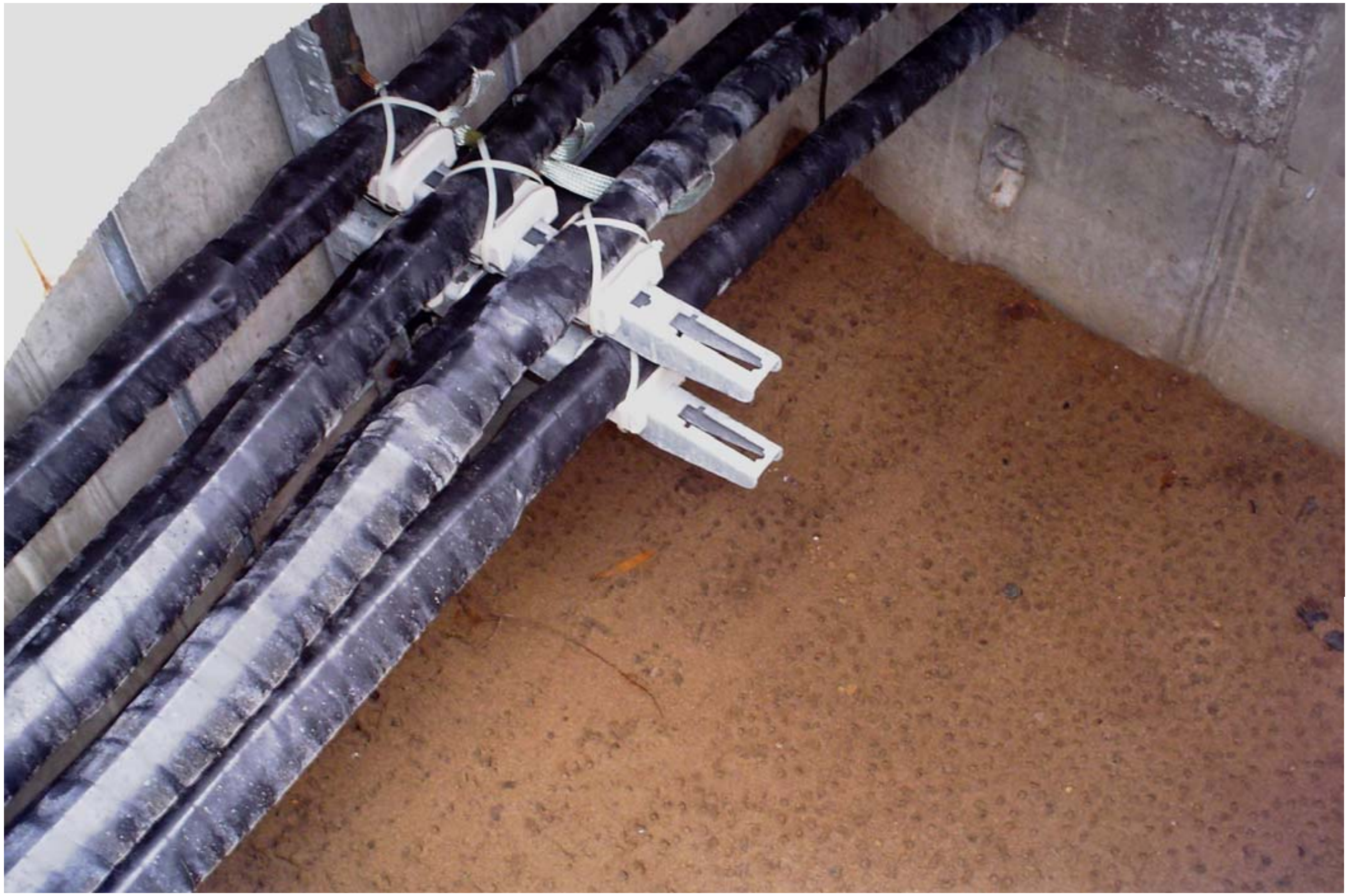
Underground Medium Voltage Cables Manhole Inspection Interval

- ACRS LR Subcommittee Questioned Adequacy of Two Year Manhole Inspection Frequency
- Inspection Frequency is Based on Actual Plant Experience, but not to Exceed Every Two Years
- Consistent with GALL XI.E3
- One Manhole in Scope of License Renewal
- Five Inspections Since September 2007 Have Shown no Signs of Water Intrusion or Accumulation

Underground Medium Voltage Cables Manhole Inspection Interval

- **Design Precludes Water Accumulation**
  - **Floor of Gravel and Sand**
  - **Approximately Ten Feet Above Water Table**
  - **Grade Around Manhole Precludes Significant Rain Water Intrusion**
- **Based on Manhole Design and Actual Plant Experience, Two Year Inspection Frequency is Considered Sufficient**

Underground Medium Voltage Cables Manhole Inspection Interval



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Underground Medium Voltage Cables Impact of Freeze/Thaw Conditions

- **Prairie Island Operating Experience was Reviewed for Evidence of Accelerated Cable Insulation Aging Related to Freeze/Thaw Conditions**
- **The Following Organizations were also Contacted:**
  - **Monticello Nuclear Generating Plant**
  - **Xcel Energy Distribution**
  - **EPRI**
  - **NEI License Renewal Electrical Working Group**
- **Accelerated Cable Insulation Aging Related to Freeze/Thaw Conditions has not Been Identified as an Issue**

Questions?

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Supporting Slides

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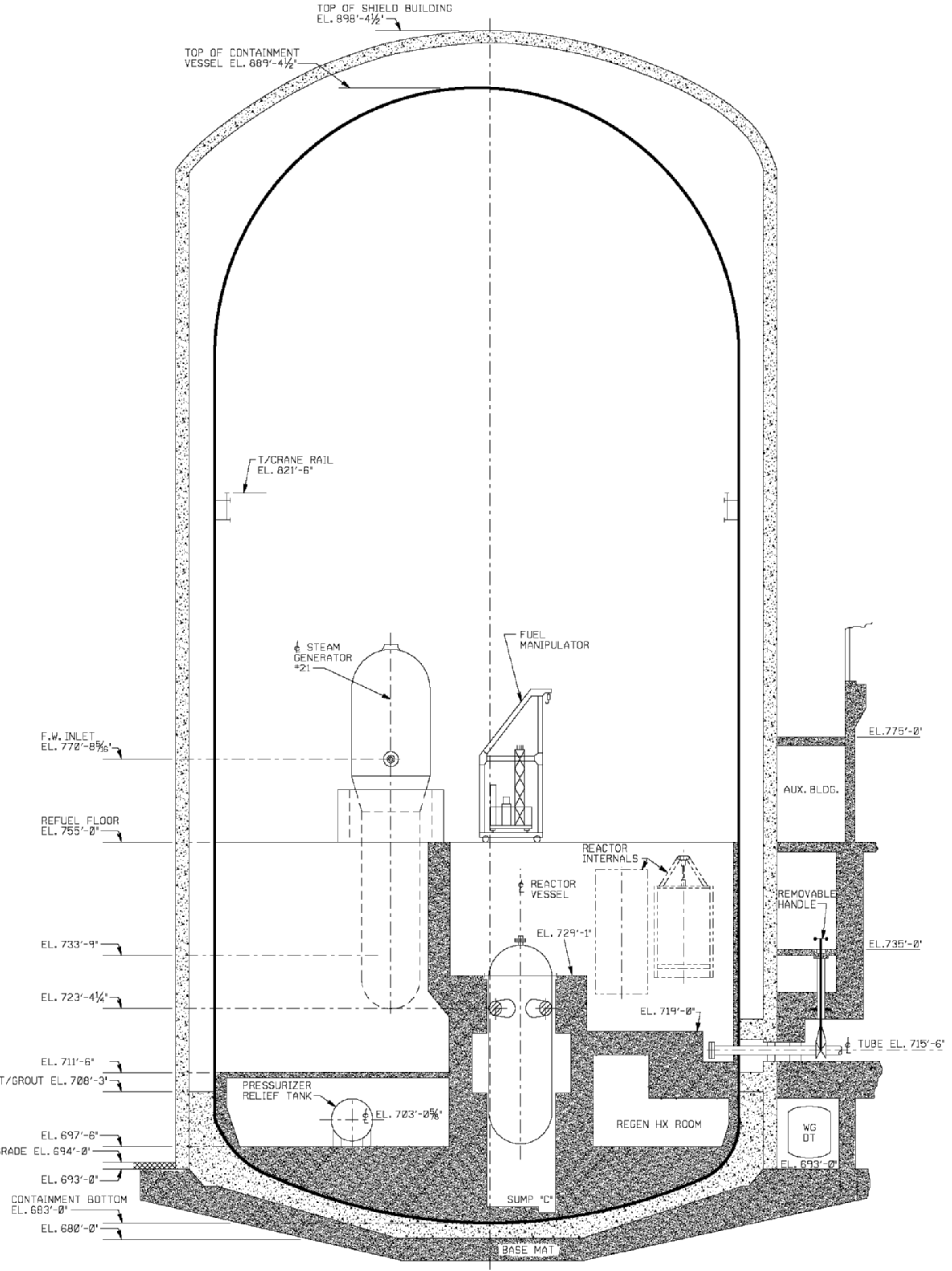
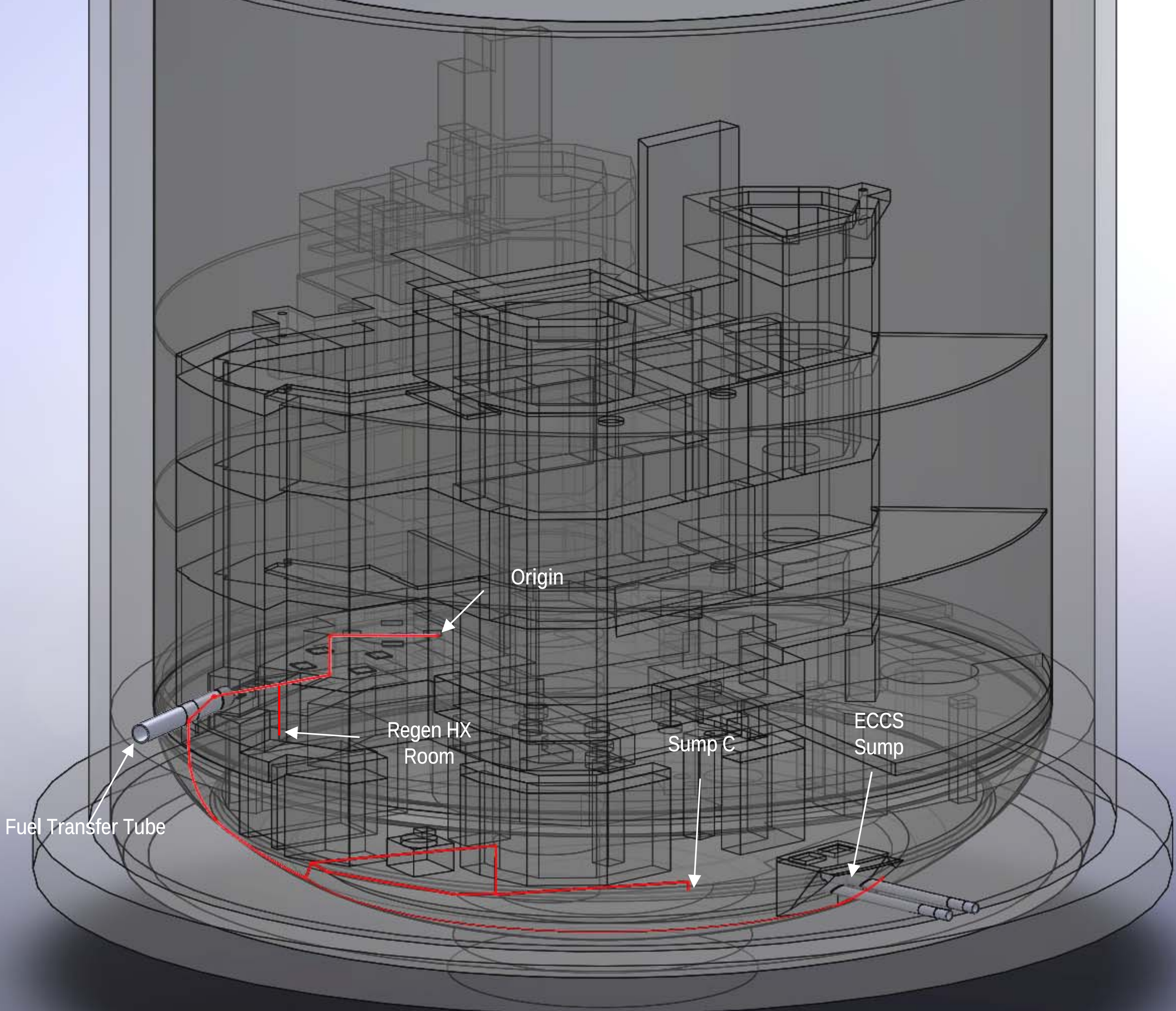
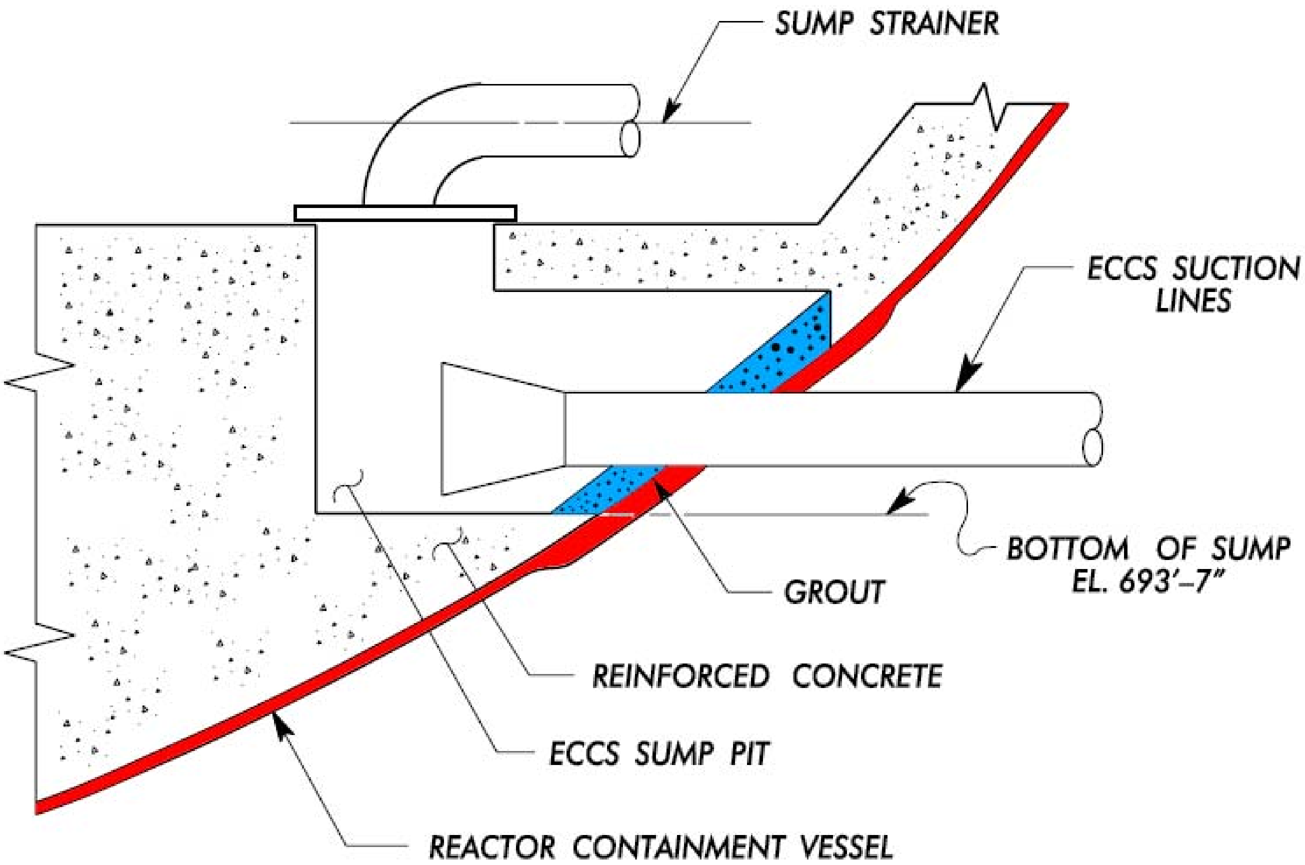

TOP OF SHIELD BUILDING
EL. 898'-4½'
TOP OF CONTAINMENT
VESSEL EL. 889'-4½"
T/CRANE RAIL
EL. 821'-6"
℄ STEAM
GENERATOR
#21
FUEL
MANIPULATOR
F.W. INLET
EL. 770'-8 5/16'
EL. 775'-0'
AUX. BLDG.
REFUEL FLOOR
EL. 755'-0"
REACTOR
INTERNALS
℄ REACTOR
VESSEL
REMOVABLE
HANDLE
EL. 729'-1"
EL. 735'-0'
EL. 733'-9"
EL. 723'-4¼"
EL. 719'-0"
℄ TUBE EL. 715'-6"
EL. 711'-6"
T/GROUT EL. 708'-3'
PRESSURIZER
RELIEF TANK
℄ EL. 703'-0⅝"
REGEN HX ROOM
WG
DT
EL. 697'-6"
GRADE EL. 694'-0'
EL. 693'-0"
EL. 693'-0"
SUMP "C"
CONTAINMENT BOTTOM
EL. 683'-0"
EL. 680'-0"
BASE MAT



Leak Paths

ECCS Sump

ECCS Sump Showing Grout



Shield Building Annulus

U.S.NRC

UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

Advisory Committee on Reactor Safeguards Prairie Island Nuclear Generating Plant, Units 1 and 2

License Renewal Safety Evaluation Report

December 3, 2009

Richard Plasse, Project Manager

Office of Nuclear Reactor Regulation

Overview

- NRC Staff Review
- License Renewal Inspections
- Items of Interest

NRC Staff Review

- Safety Evaluation Report with Open Items was issued June 4, 2009
- 168 Requests for Additional Information Issued
- 37 Applicant Commitments (Unit 1)
- 37 Applicant Commitments (Unit 2)

NRC Staff Review (cont.)

- Applicant submitted additional information by letters dated 5/12/09, 6/5/09, 6/24/09, 8/7/09, and 8/21/09 to address open items
- Staff closed all 3 open items
- SER issued on October 16, 2009
- Staff determined that the requirements of 10 CFR 54.29(a) have been met

71002 Inspection

- 10 CFR 54.4(a)(2) Scoping & Screening Non-Safety SSCs
- Reviewed 24 of 43 Aging Management Programs
- Operating Experience Review
- Inspection Observed by the Prairie Island Indian Community Tribal Council President
- Inspection Conclusions
  - Scoping of non-safety SSCs and Aging Management Programs are acceptable
  - Inspection results support a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained

Section 3: Aging Management Review Results

<u>Section 3.0.3</u> – Aging Management Programs (AMPs)

	Plant-Specific	Consistent with GALL	With Exception	With Enhancement	With Exception and Enhancement
Existing	1	11	2	9	6
New	1	11	2	0	0

Section 2: Structures and Components Subject to Aging Management Review

Section 2.1: Scoping and Screening Methodology

- Open Item 2.1.4.1.2-1
  - Radioactive waste gas decay tank
    - UFSAR Section 14.5.3.1 describes the tank as safety related
    - Staff determined that this system should be within scope of LR in accordance with 10 CFR 54.4(a)(1)(iii)
    - Applicant added to scope, item is closed

Section 3: Aging Management Review Results

Section 3.0.3.1.21: PWR Vessel Internals Program

- Open Item 3.0.3.1.21-1
  - On May 12, 2009, the applicant submitted an amended PWR Vessel Internals Program
  - Staff completed review of new AMP and associated aging management review line items
  - This item is closed

Section 3: Aging Management Review Results

Section 3.0.3.2.17: Structures Monitoring Program

- Open Item 3.0.3.2.17-1
  - Issue with water seepage from the refueling cavity into the containment sumps
- Root Cause
  - In April 2009, the applicant determined that welds in two embeds in the refueling cavity floor were the source of leakage
- Applicant committed to:
  - Permanently repair refueling cavity leakage
  - Remove concrete and UT the containment vessel at a low point in containment
  - Inspect exposed rebar for degradation
  - Remove and test concrete from wetted area
- Based on commitments this item is closed

ACRS Items of Interest

- Condensate Storage Tank UT Inspections
- Medium Voltage Cable Manhole Inspections
- Exposure of Electrical Cables and Direct-Buried Cables to Freeze/Thaw Cycles
- Refueling Cavity Water Leakage

Conclusion

The staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB and that the requirements of 10 CFR 54.29(a) have been met.

Sunil Weerakkody, PhD

Deputy Director, Fire Protection

Division of Risk Assessment

Office of Nuclear Reactor Regulation

Regulatory Guide 1.205, Revision 1
Standard Review Plan Section 9.5.1.2

Advisory Committee on Reactor Safeguards

December 3, 2009

Overview

- 10 CFR 50.48(c) and NFPA 805, 2001 edition
  - Comprehensive and coherent regulation
  - Complex – needed pilot applications in order to fully understand nuances
- Regulatory Guide 1.205, Revision 1
  - Improved and additional guidance to facilitate compliance
  - Clear and consistent Regulatory Positions
  - Fully vetted:
    - Stakeholder comments received and considered
    - ACRS members' input (June 1, August 18, November 13, 2009)
    - Office concurrence received (NRR, NRO, RES, OGC)
    - Final draft shared with public (September 10, October 29, 2009)

Briefing Objectives

- Receive ACRS endorsement:
  - Issue RG 1.205, Rev. 1
  - Issue SRP 9.5.1.2 (new section)

✓ *This guidance improves clarity and provides regulatory stability for both pilot plants and non-pilot plants*

✓ *Issuance of RG 1.205, Rev. 1, and SRP 9.5.1.2 at this time fosters clarity and regulatory stability*

Steven Laur

Senior Level Advisor

Division of Risk Assessment

Office of Nuclear Reactor Regulation

Regulatory Guide 1.205, Revision 1
Standard Review Plan Section 9.5.1.2

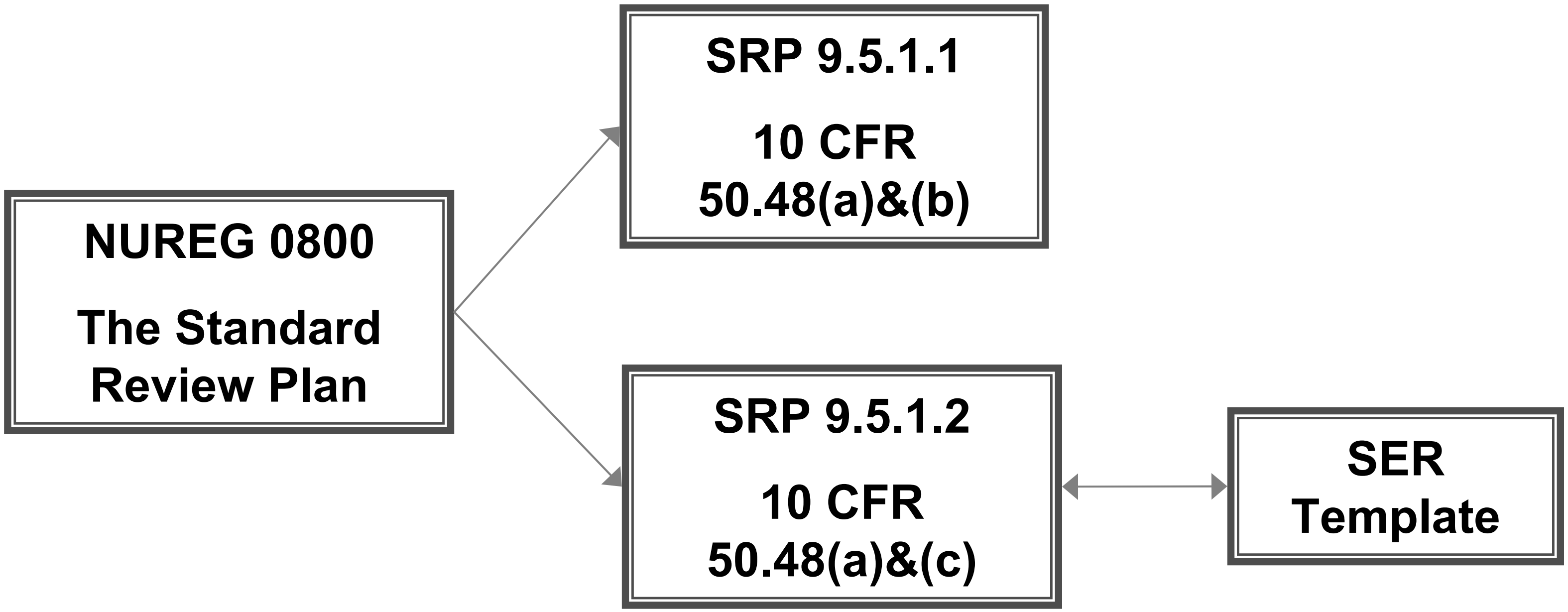
Advisory Committee on Reactor Safeguards

December 3, 2009

Discussion Topics

- SRP and RG Framework
- Motivation and Purpose of Revisions
- SRP 9.5.1.2 – Guidance Consistent with DG-1218
- Resolution of Comments on Revised RG
- Stakeholder Interaction
  - Public
  - ACRS Reliability and PRA Subcommittee
- Questions

Standard Review Plan Framework



SRP 9.5.1.2: "Risk-informed, Performance-based Fire Protection Program"

Standard Review Plan 9.5.1.2

Guidance to NRC staff is consistent with RG 1.205, Rev. 1*

Follows general SRP format:

I. AREAS OF REVIEW

II. ACCEPTANCE CRITERIA

III. REVIEW PROCEDURE

IV. EVALUATION FINDINGS

V. IMPLEMENTATION

VI. REFERENCES

Attachment 1 – Risk-Informed/Performance-Based Fire Protection Program LAR Acceptance Review Matrix

**** Therefore, this presentation will focus on RG 1.205***

RG 1.205 Revision 1 Framework

10 CFR 50.48(c)

& NFPA 805, 2001 Ed.

RG 1.205

Rev 1

One Method Acceptable to NRC

Endorse with exceptions

NEI 04-02

Rev 2

Guidance for Rule Implementation

DG-1218: "Risk-informed, Performance-based Fire Protection Program for Existing Light-water Nuclear Power Plants"

Motivation for Revision 1

- Drivers for the revision to RG 1.205
  - NEI 04-02, Revision 2
  - Closed FAQs after NEI 04-02 revision
  - Ongoing pilot plant meetings
  - Pilot plant license amendment request review, including regulatory audits at both Oconee and Harris
- Most of the changes were needed to:
  - Clarify guidance; e.g., plant change versus fire risk evaluations
  - Add missing guidance – additional risk of certain recovery actions (next slide)
- The goal is to foster full and scrutable compliance with the new regulation

Purpose of Additional Guidance

- NEI 04-02 provided guidance that some previously approved recovery actions did not require a risk assessment per NFPA 805 Chapter 4.
- This guidance is inconsistent with NFPA 805 Sections 4.2.3.1 and 4.2.4.2.
- The original RG did not provide guidance in this area – Revision 1 corrects that omission.

Stakeholder Comment Topics

- Fire Probabilistic Risk Assessment (PRA)
- Cumulative Risk
- Sample License Condition
- Risk of Previously-Approved Recovery Actions (RAs)
- Primary Control Station

Fire PRA

- Public Comments on Fire PRA Methods
  - Clarify how to meet the NFPA 805 requirement that methods be "acceptable to the AHJ"
  - Limit discussion of fire PRA methods to the "cause/effect" relationship
  - Do not limit methods to those in "topical reports"

Fire PRA (cont'd)

- NRC Response – Fire PRA Methods
  - Most of the public comments in this area were incorporated.
  - The guidance was clarified such that licensee may model cause/effect relationship with methods:
    - That have been used in the peer-reviewed baseline PRA;
    - That have been endorsed by NRC through a license amendment or NRC approval of generic methods specifically for use in NFPA 805 risk assessments; or,
    - That have been demonstrated to bound the risk impact.

Fire PRA (cont'd)

- Public Comments on Fire PRA Model
  - Provide guidance on fire PRA model updates and upgrades after transition
  - Provide clear fire PRA submittal guidance
- NRC Response – Fire PRA Model
  - Updated RG Section 4.3 to reference RG 1.200 and the ASME/ANS PRA Standard which contains the suggested guidance

Fire PRA (cont'd)

- Public Comments on Required Risk Assessments
  - Clarify when plant change evaluations are required
  - Clarify which recovery actions need risk assessment
  - Limit scope of recovery actions to "success path"
- NRC Response – Required Risk Assessments
  - RG revised to discuss both plant change evaluations and fire risk evaluations explicitly
  - Additional guidance provided regarding previously approved recovery actions (later slides)
  - Scope of risk evaluations limited to match NFPA 805 §4.2.3.1

Cumulative Risk

- Public Comments
  - There is no valid basis to track cumulative risk
  - Do not evaluate the total change in risk associated with implementation of NFPA 805 using RG 1.174
- NRC Response
  - Comments not incorporated
  - NFPA 805 requires consideration of cumulative risk
  - RG 1.174 guidelines are appropriate when the fire risk performance-based approach is used

Sample License Condition

- Public Comment
  - The transition license conditions would preclude self-approval of changes before full implementation
- NRC Response
  - RG changed to allow self approval, during the transition period, of changes that have no more than a minimal risk increase

Previously Approved RAs

- Public Comment
  - Previously approved recovery actions should be deemed to meet the deterministic requirements of NFPA 805, Section 4.2.3

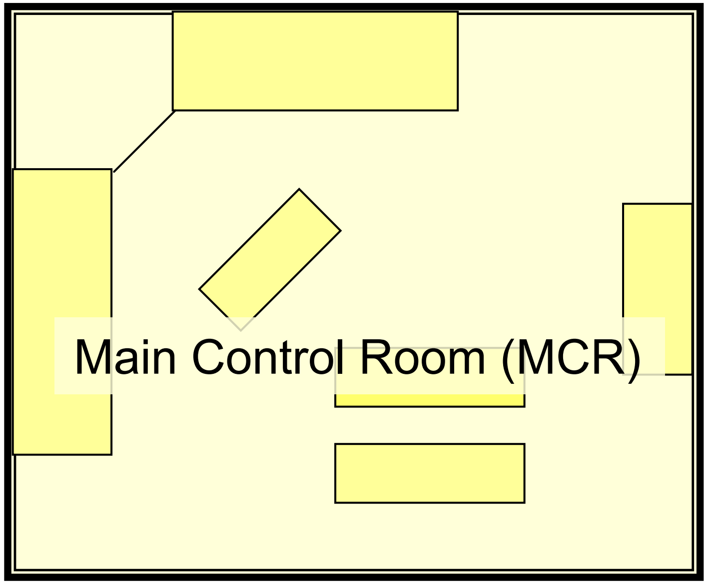
Previously Approved RAs (cont'd)

- NRC Response
  - Comment not incorporated because such guidance would be contrary to the requirements in NFPA 805
  - Additional risk (ΔCDF; ΔLERF) of certain recovery actions must be evaluated
  - The risk is acceptable based on previous approval*
  - This additional risk is considered when evaluating the acceptability of other, proposed risk contributions when using the performance-based approach

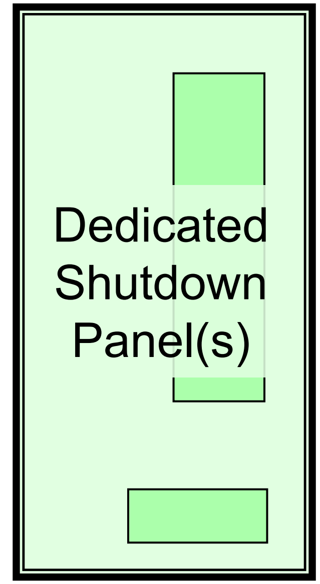
**Unless circumstances indicate that a backfit under 10 CFR 50.109 is warranted on an adequate protection or cost-beneficial safety improvement basis.*

Primary Control Station

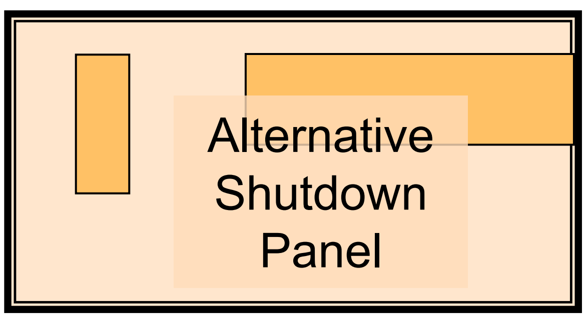
- Public Comment
  - The benefit of defining *primary control station* is not evident
- ACRS Subcommittee Discussion
  - Draft definition of primary control station could lead to undesired classification of recovery actions
- NRC Response
  - Clarified the definition of primary control station to allow “carry over” (subject to certain conditions) of approved manual actions (next slide)



Control Room actions are not recovery actions



Dedicated Shutdown Panel† actions are not recovery actions when command and control is shifted from the MCR



Alternative Shutdown† actions are not recovery actions when control is shifted from the MCR provided:

- Primary command & control
- Requisite controls, indications, & communications
- Multiple components controlled from location

† *As defined in Appendix R III.G.3 and NRC-approved*

Public Meeting Interaction

- The NRC staff incorporated the majority of stakeholder comments
- Remaining regulatory positions are necessary to foster clarity and regulatory stability
- Industry expressed unresolved concerns:
  - Guidance not fully vetted (e.g., fire risk evaluations)
  - Recovery Actions (e.g., definition of “success path”)
  - Post-Transition Change Evaluation Process (RG focuses on detailed risk evaluation)

Public Meeting Interaction (cont'd)

- Members of industry, including both pilot plant licensees, agreed that RG 1.205, Rev. 1 should be issued ASAP to contribute to NFPA 805 regulatory stability
- NRC will continue to utilize the FAQ process to further refine implementation details

ACRS Subcommittee Interaction

- Changes were made based on feedback from members of the Reliability and PRA Subcommittee
  - Incorporated a flow chart to clarify how the risk of previously-approved recovery actions should be considered
  - Incorporated the comments received from the ACRS subcommittee with regard to simplifying the definition of "primary control station"
  - Made several changes to clarify intent of the guidance

Conclusion

- Regulatory Guide 1.205, Revision 1 and SRP 9.5.1.2
  - Incorporate the significant lessons from the pilot plants
  - Provide clear and consistent guidance to facilitate compliance with a comprehensive and complex regulation
  - Fully considered stakeholder comments
    - majority of comments were incorporated into the final drafts
    - a few stakeholder comments were not incorporated because of requirements in the rule
- Issuance of RG 1.205, Rev. 1, and SRP 9.5.1.2 at this time fosters clarity and regulatory stability
- The staff requests the ACRS endorse issuance of these two documents

Questions?

CONTINGENCY SLIDES

RISK OF RECOVERY ACTIONS IN NFPA 805

4.2.3.1 One success path of required cables and equipment to achieve and maintain the nuclear safety performance criteria without the use of recovery actions shall be protected by the requirements specified in either 4.2.3.2, 4.2.3.3, or 4.2.3.4, as applicable. Use of recovery actions to demonstrate availability of a success path for the nuclear safety performance criteria automatically shall imply use of the performance-based approach as outlined in 4.2.4.

4.2.4* Performance-Based Approach. When the use of recovery actions has resulted in the use of this approach, the additional risk presented by their use shall be evaluated.

When the fire modeling or other engineering analysis, including the use of recovery actions for nuclear safety analysis, is used, the approach described in 4.2.4.1 shall be used.

When **fire risk evaluation** is used, the approach described in 4.2.4.2 shall be used.

4.2.4.1 Use of Fire Modeling
The approach in 4.2.4.1.1 through 4.2.4.1.6 shall be used.

4.2.4.2 Use of Fire Risk Evaluation. Use of fire risk evaluation for the performance-based approach shall consist of an integrated assessment of the acceptability of risk, defense-in-depth, and safety margins.

The evaluation process shall compare the risk associated with implementation of the deterministic requirements with the proposed alternative.

The difference in risk between the two approaches shall meet the risk acceptance criteria described in 2.4.4.1.

The fire risk shall be calculated using the approach described in 2.4.3.

2.4.3* Fire Risk Evaluations.
The PSA methods, tools, and data … for the performance-based valuation of fire protection features (*see 4.2.4.2*) or … the change analysis described in 2.4.4 shall conform with … 2.4.3.1 through 2.4.3.3.

2.4.4.1* Risk Acceptance Criteria.
The change in public health risk from any plant change shall be acceptable to the AHJ. CDF and LERF shall be used to determine the acceptability of the change.

Fire PRA – Quality

- Fire PRA technical adequacy – 2 aspects
  - Underlying PRA (i.e., the baseline model)
  - Analyses, assumptions, and approximations to map the cause-effect relationship associated with the application
- Method for addressing
  - Baseline PRA - conform to the peer review and self assessment processes in RG 1.200 (PRA Standard)
  - Fire Risk assessments - describe the specific modeling of each cause-effect relationship associated with the application
- Submittal guidance
  - Submit documentation described in Section 4.2 of RG 1.200
  - Generally accept Capability Category (CC) II for FPRA
  - Justify use of CC I for specific supporting requirements
  - Evaluate whether parts of the FPRA need to meet CC III

Fire Risk Evaluations

- Two similar (but different) risk evaluations in NFPA 805
  - Fire Risk Evaluations
    - Demonstrate adequacy of an alternate to the deterministic criteria
    - Each fire area (as applicable) and total plant fire risk change
  - Plant Change Evaluations
    - Changes to the “previously approved Fire Protection Program”
    - Cumulative risk must be considered
      - Cumulative risk calculation starts at implementation of NFPA 805 (including all necessary modifications)
    - Baseline for evaluating the cumulative affect of changes to the fire protection program is based on the fire risk at the point of implementation of NFPA 805

Enhanced Sample License Condition

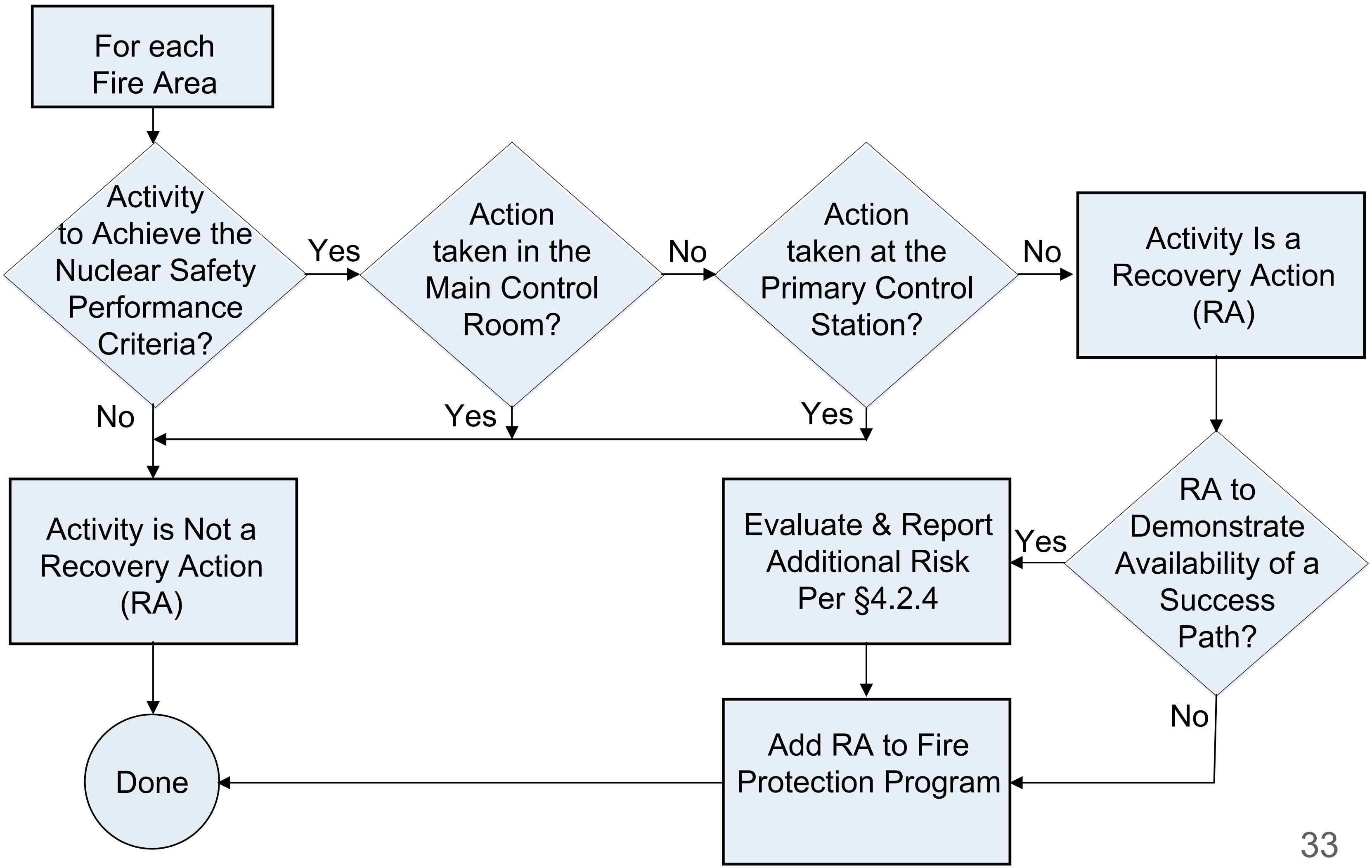
- Allow non-risk informed changes to the fire protection program that have no more than a minimal risk impact
  - Consistent with intent of NEI 04-02, Revision 2
  - Allow screening per process approved in the NFPA 805 license amendment
- Incorporated information regarding *functional equivalency* and *adequate for the hazard* (FAQ-06-0008) into the sample license condition (from §3.2.4)

Recovery Actions

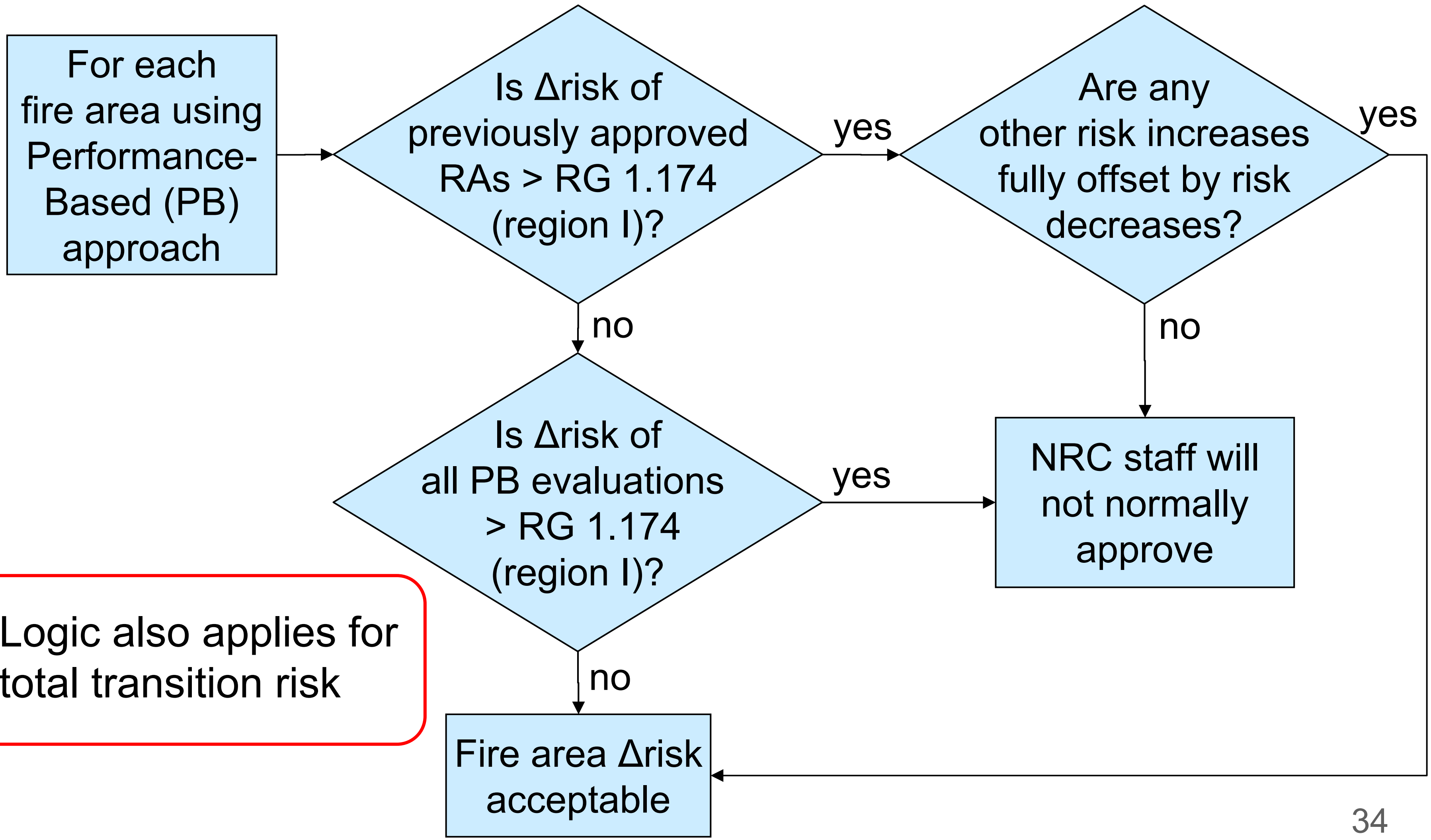
Definition: “Activities to achieve the nuclear safety performance criteria that take place outside of the main control room or outside of the primary control station(s) for the equipment being operated including the replacement or modification of components”

(NFPA 805 §1.6.52)

Recovery Actions in NFPA 805

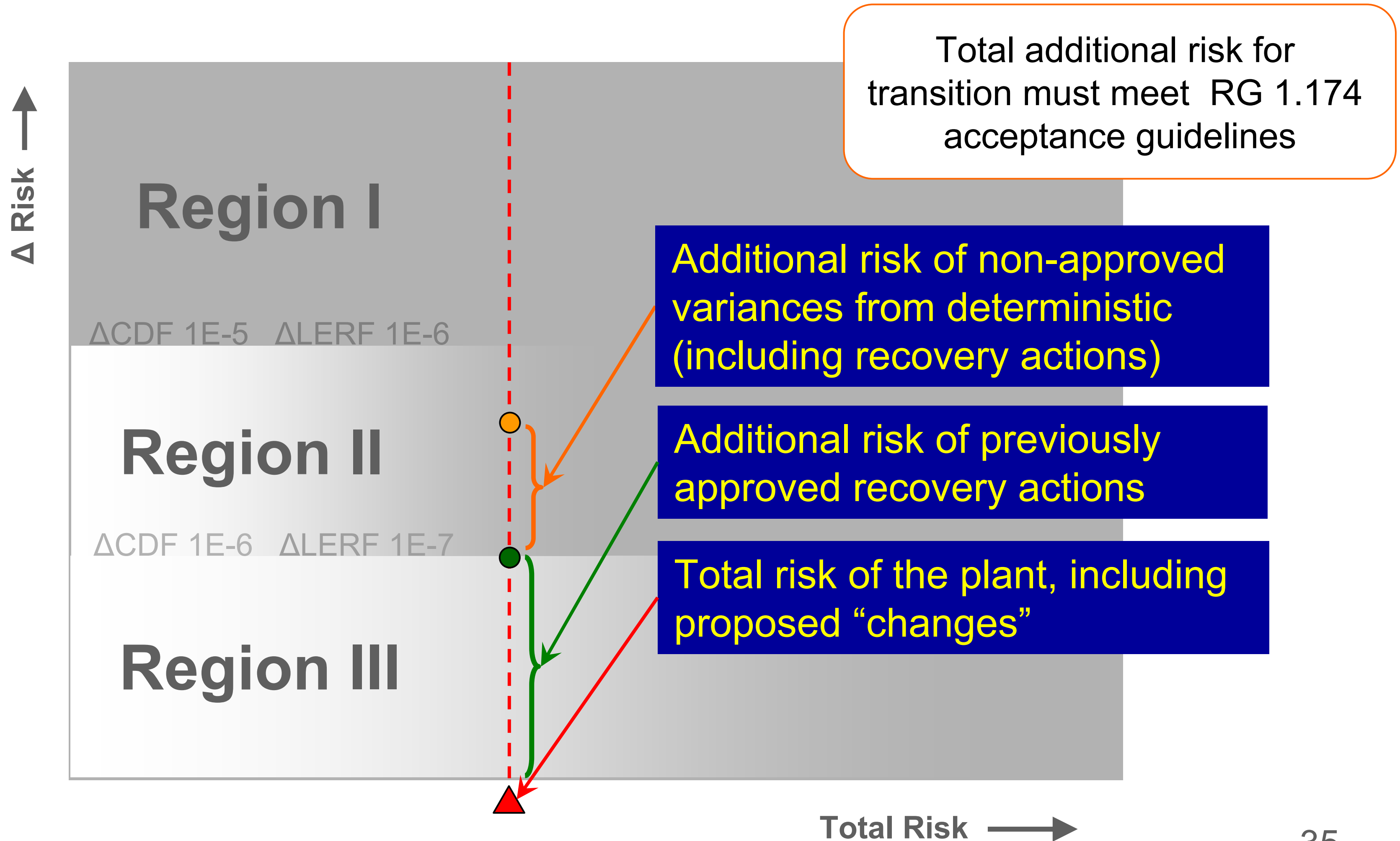


Application of RG 1.174 to NRC Staff Review During Transition (by Fire Area)

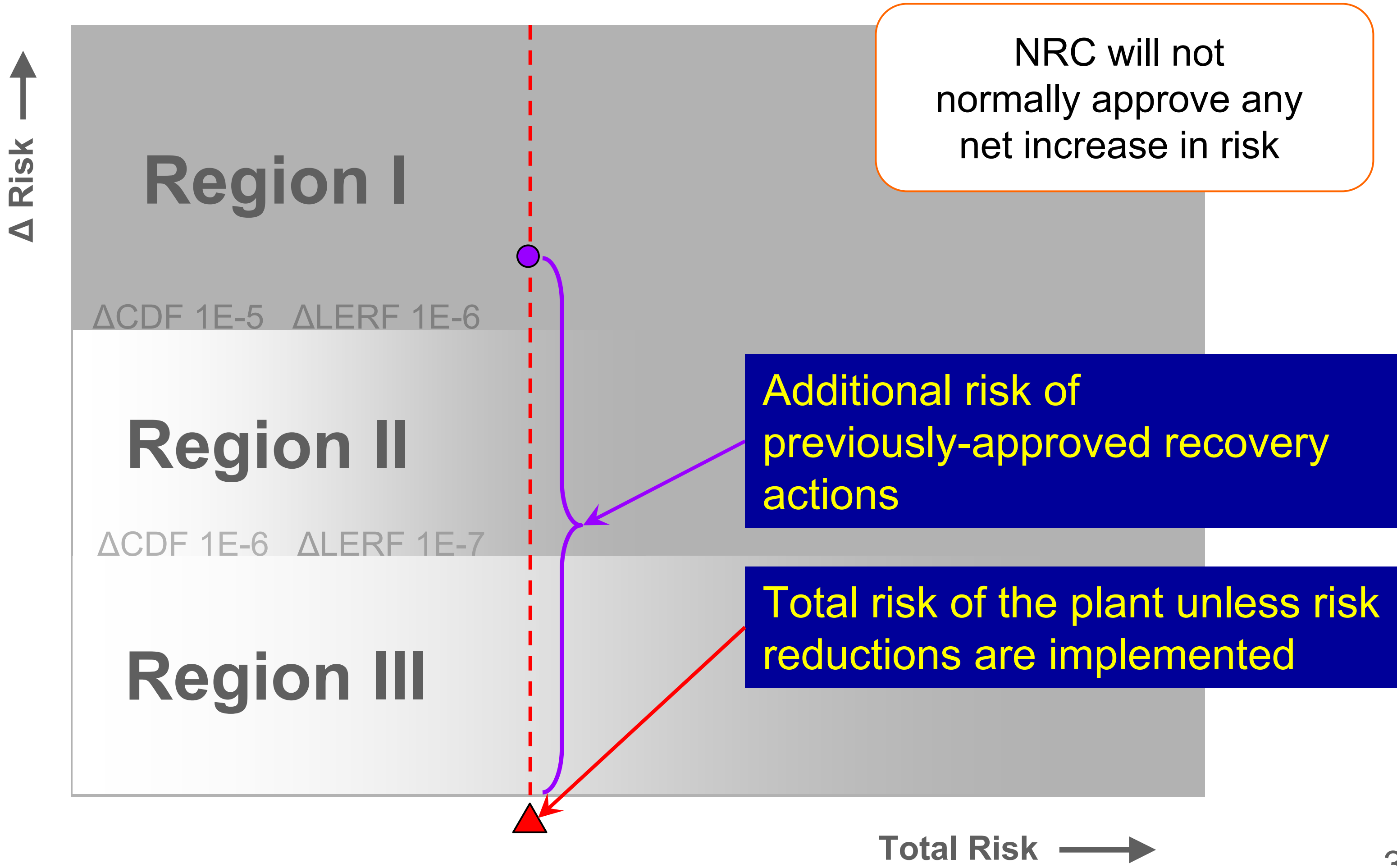


Logic also applies for total transition risk

Case 1: Additional Risk of Previously-Approved Recovery Actions is Within RG 1.174



Case 2: Additional Risk of Previously-Approved Recovery Actions Exceeds RG 1.174



Clarified Definition of Primary Control Station

- RG 1.205, Rev. 1 defines “primary control station” (details on next slide)
- The definition recognizes that NRC-approved Appendix R III.G.3 approaches should “carry over” to NFPA 805 if certain criteria are met
- The staff incorporated the comments received from the ACRS subcommittee with regard to simplifying the definition

SRP REVIEW PROCEDURE
(Section III)

1. PROGRAMMATIC REVIEW OF LICENSE AMENDMENT REQUEST
2. FUNDAMENTAL FIRE PROTECTION PROGRAM ELEMENTS AND MINIMUM DESIGN REQUIREMENTS
3. NUCLEAR SAFETY PERFORMANCE CRITERIA
4. RADIOACTIVE RELEASE PERFORMANCE CRITERIA
5. RISK ASSESSMENTS AND PLANT CHANGE EVALUATIONS
6. MONITORING PROGRAM
7. PROGRAM DOCUMENTATION, CONFIGURATION CONTROL, AND QUALITY ASSURANCE

✓ *Pilot plant Safety Evaluation Reports will follow this same general outline.*

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Presentation to the ACRS

Design Basis ESBWR Containment Long-Term Pressure Analysis

Presented by

Hanry A. Wagage, NRO/DSRA/SBCV
Allen Notafrancesco, RES/DSA/FSTB
Hossein Esmaili, RES/DSA/FSTB

December 3, 2009

Project and Technical Review Team

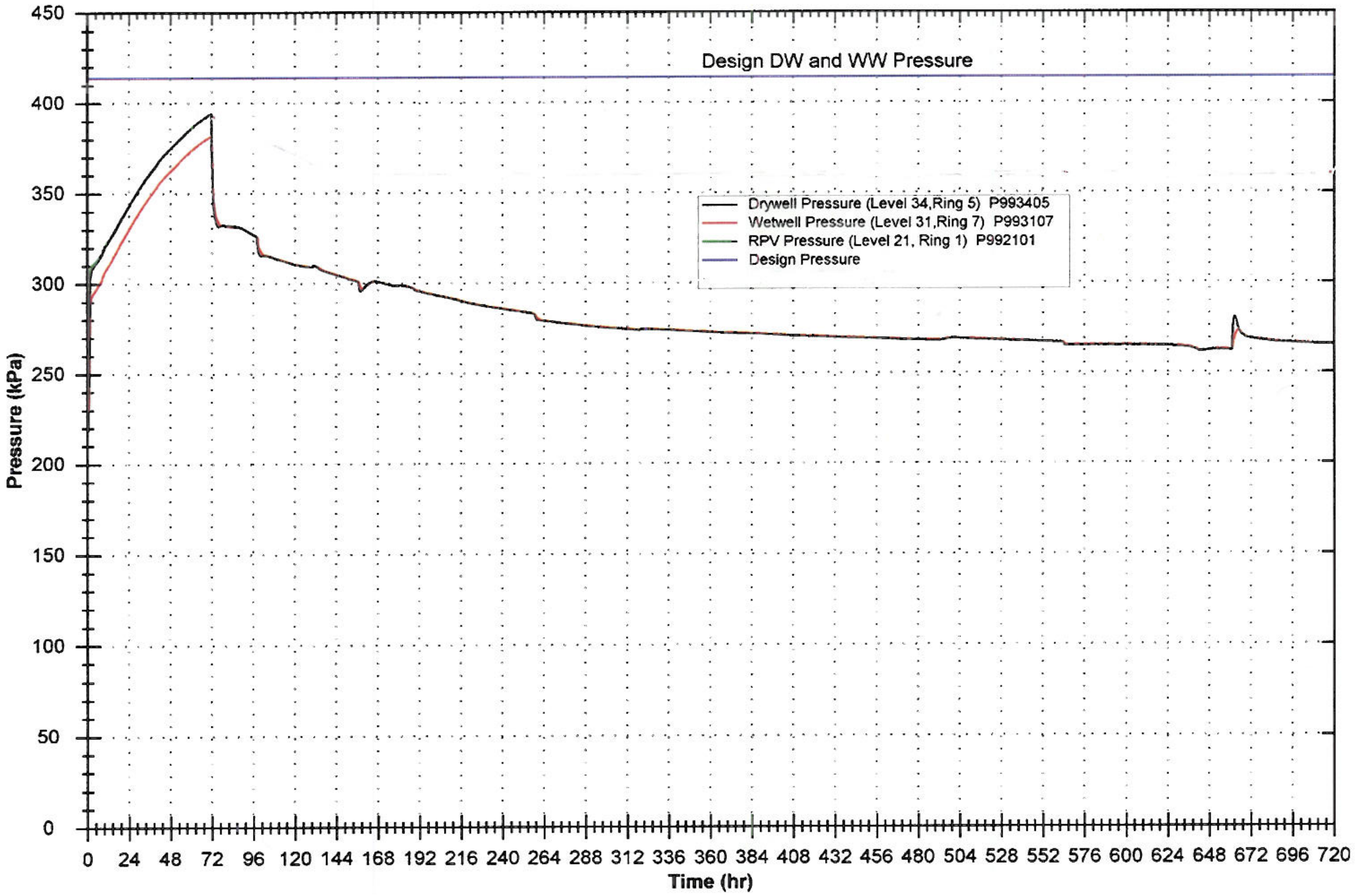
- Project Managers
  - Ilka Berrios, Chapter 6 Project Manager
  - Amy Cubbage, ESBWR Lead Project Manager
- Technical Reviewers
  - Hanry Wagage, NRO/DSRA/SBCV - Lead Reviewer
  - Allen Notafrancesco, RES/DSA/FSTB
  - Hossein Esmaili, RES/DSA/FSTB
  - Jack Tills, Consultant, JTA Inc.

Regulatory Criteria

- 10 CFR 50.46(b)(5)─Long-term cooling
- GDC 38─Containment heat removal

GDC 38—Containment Heat Removal

- Systems credited:
  - Suppression pool
  - Passive containment cooling system (PCCS)
  - Credited after 3 days:
    - PCC tank refill
    - PCC vent fans
    - Passive autocatalytic recombiner system
- SRM to SECY 94-084 – cold shutdown (93.3 °C (200 °F)) versus safe shutdown (215.6 °C (420 °F))
- TRACG and MELCOR analysis
- ESBWR compliance with GDC 38 is under review



Containment pressure for MSLB bounding case (DCD Figure 6.2-14e1)

MELCOR Code

Uses state-of-the-art plant analysis approach

Fully integrated analysis (includes the RCS)

Focused on ESBWR related phenomena

Performed targeted code assessments

Presentation Outline

- Background
  - Plant Overview
  - Calculational Approach

- MELCOR ESBWR Plant Model

- MELCOR DBA calculation for ESBWR Long-term Containment Cooling (peak pressure)
  - Passive Period (0 to 72 hours)
  - Intervention Period (72 to 720 hours)

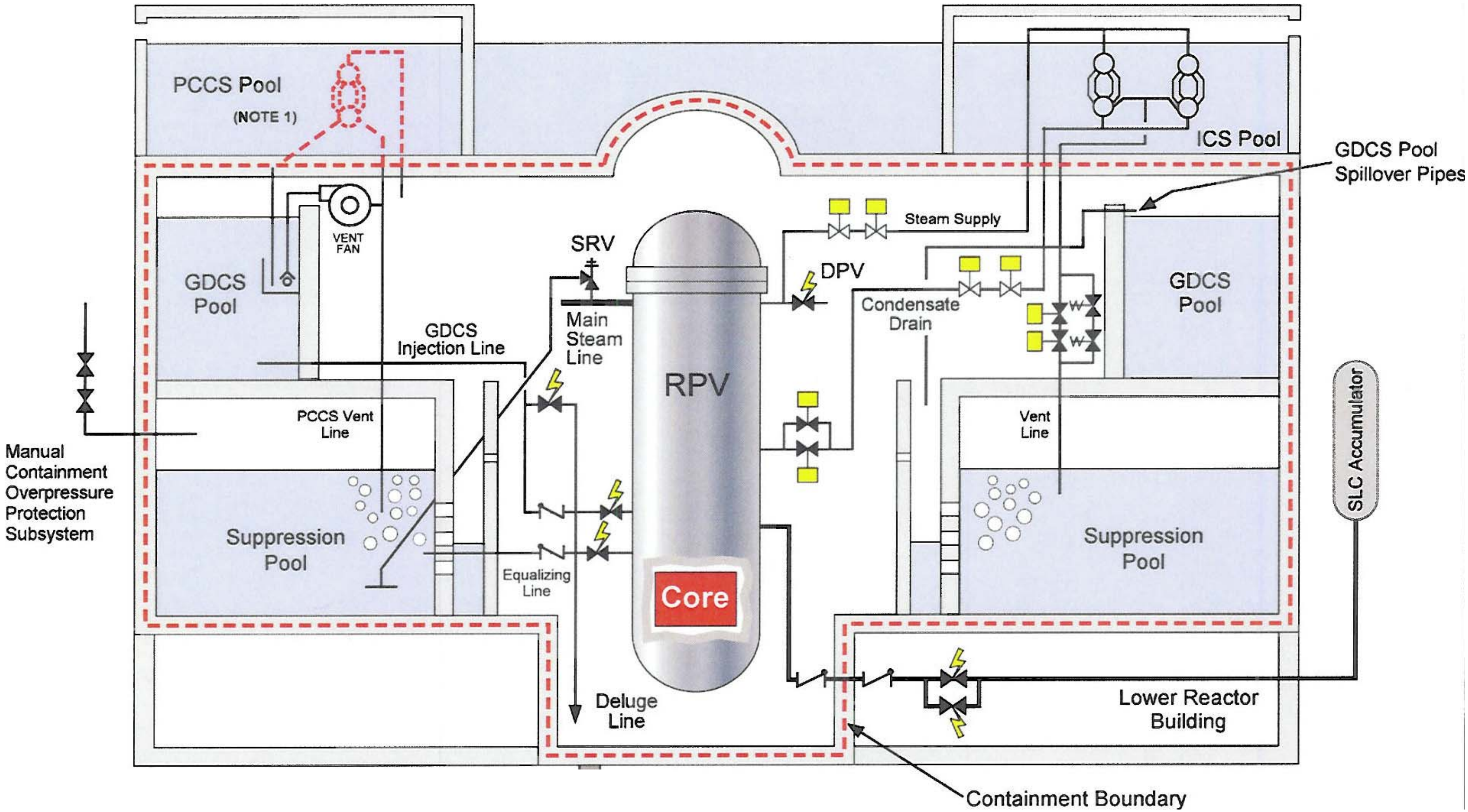
Containment Audit Analysis

Design Basis Analysis (DBA)- Peak Containment Pressure

- Bounding approach, i.e., maximize mass/energy into containment & minimize rate of energy removal
  - Worst postulated LOCA; large RCS pipe breaks
  - Limiting single active failure
  - Extreme plant Tech. Spec. limits, e.g., upper P(init.)

- Containment Phenomena Modeling
  - Models inaccuracies/uncertainties should reflect an inherent conservative “bias” in relation to the key figure-of-merit

Schematic of ESBWR containment (DCD Figure 6.2-15)



MELCOR ESBWR Assessment (Passive Period)

Three Accident Phases

- Blowdown
- GDCS draindown and recovery
- Long-term

Dominant phenomena For maximum pressure Prediction

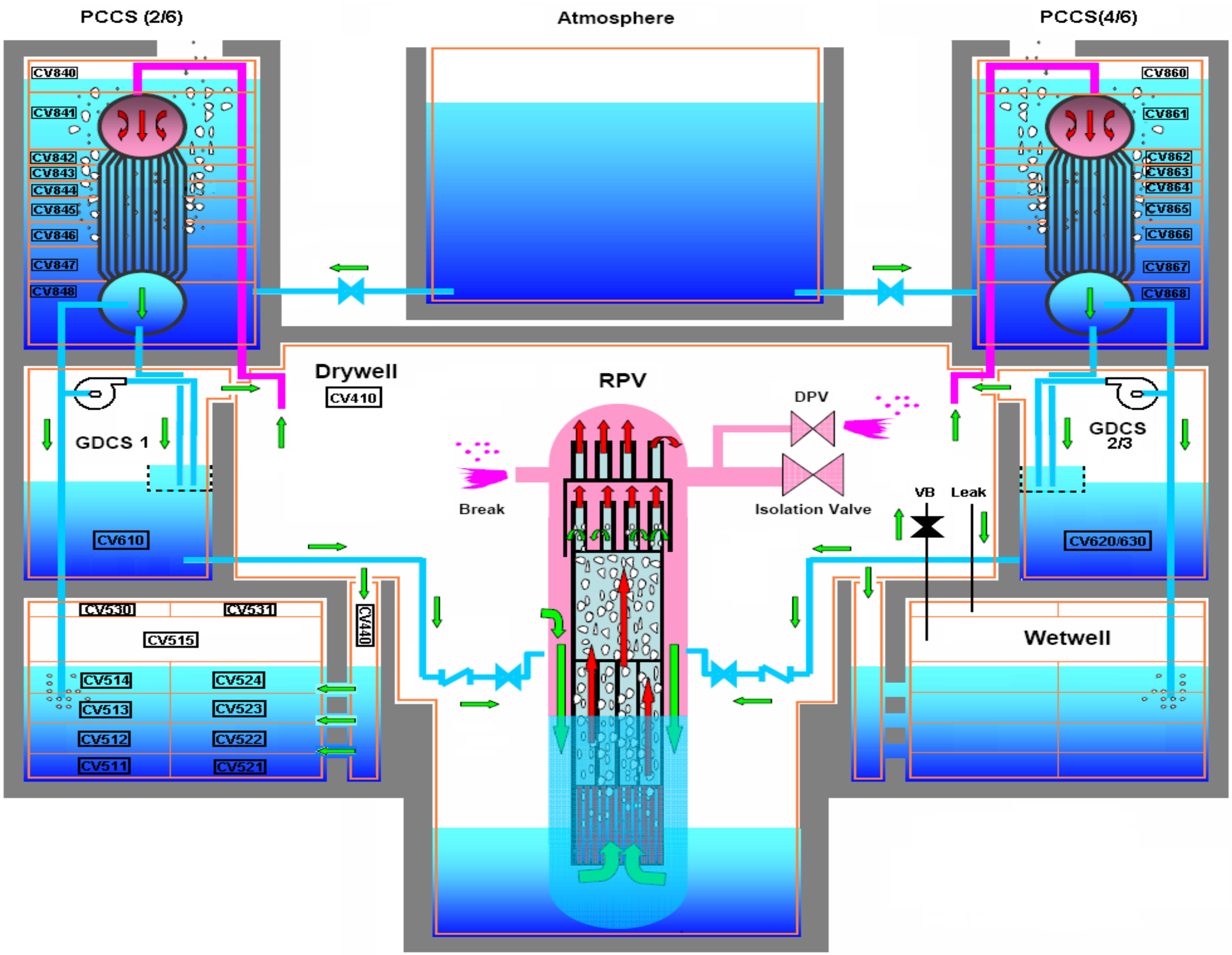
Event: Phenomena/Process Modeling	Validation type (Code-to-Code) (Integral Effects Test – IET) (Separate Effects Test – SET)	MELCOR References [Related]
Blowdown:		
Break & Main vent clearing Wetwell pressurization	Code-to-Code GE TRACG (ESBWR break discharge)/GE Analytical Model (Grand Gulf licensing)	ESBWR Performance Study Report(1) Presentation to MCAP(2) on Mark III type blowdowns
GDCS:		
Drywell mixing/purging Vacuum breaker operation PCCS start-up GDCS draindown RPV Quenching and Steaming	IET – ISP-42: Phase A – PCCS start-up Phase B – GDCS Discharge IET – GE Tests, P-Series P1	PANDA Report (3) Presentation to CSARP (4) on PANDA Modeling and Calculations for ISP42
Long-term:		
PCCS degradation/noncondensables	SET – PANTHERS PCC/MIT/UCB (Note: PANTHERS is a prototypical component test of PCC unit; whereas, MIT/UCB tests are single tube tests)	PANDA Report(3) PANTHERS Analysis Appendix (3) [CONTAIN MIT & UCB Single tube (5), CONTAIN PANTHERS Rpt (6)]
PCCS "bounding"	IET – ISP-42 Phase C – Long-term decay heat removal Phase D – Overloaded PCCS IET – P1	PANDA Report (3)
PCCS venting	IET – ISP-42/P8	
PCCS tank boil-down/reflooding	IET – P8 SET – PANTHERS	
DW trapping & distribution noncondensables	IET – ISP-42 Phase E – Release of hidden air IET -- P7 (helium)	
Wetwell Pool Interface HMT	IET – ISP-42: Phases A-E	
Wetwell wall heat and mass transfer (HMTA)	SET – Dehbi tests (MIT), IET – CVTR	MELCOR CVTR Report & Appendices (7)
Bypass leakage	Code-to-Code, analytic assess	---

MELCOR ESBWR Assessment (Intervention Period)

- **Early Transient**
  - **Fans on**
- **Stabilization**
  - **Upper pool**
- **Late Transient**
  - **Fan flow**

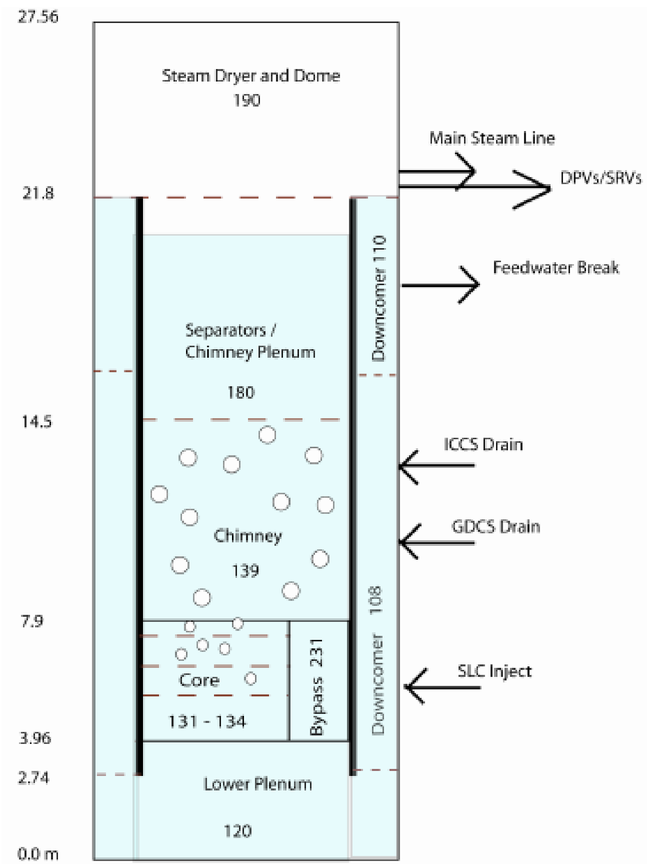
Event: Phenomena/Process Modeling	Validation type (Code-to-Code) (Integral Effects Test – IET) (Separate Effects Test – SET)	MELCOR References [Related]
Early Transient (72 – 76 hrs.):		
Fan head/flow variation	(TRACG Semiscale pump) TRACG/MELCOR comparison	Simulate TRACG input w fan curve (constant flow at present)
Vacuum breaker actuation PCC efficiency (low M_a) Gas mixing and transport in upper DW	IET – ISP-42 Phase A – PCCS start-up Phase B – GDCS Discharge Phase E – Air injection SET (PANTHERS) SET (UCB/MIT single tube)	PANDA Report (3) w Appendices (PANTHERS) PANTHERS IC Draft Report [CONTAIN PANTHERS Report; SBWR PCCS Assessment Report]
DW/WW reverse bypass flow	(TRACG/MELCOR analytic comparisons)	MELCOR Audit Report (passive period)
Gas trapping	IET – ISP-42 Phase A – PCCS start-up Phase E – Air injection P-series (P7 – He injection)	PANDA Report (3) MELCOR Interim Audit Report
Stabilization (3 – 7 days):		
PCC efficiency (intermediate M_a)	SET (PANTHERS) SET (UCB/MIT single tube)	PANDA Report (3) w Appendices (PANTHERS) [SBWR PCCS Assessment Report (1994)]
Re-circulation flow/conc. (DW – PCC – GDCS)	IET – T2.1/T2.2 PANDA (PCC – DW)	---
WW wall H&M transfer	Uchida/Dehbi	CVTR Report (SAND2008-1224)
WW pool H&M transfer	--	--
DW/WW reverse bypass flow	(TRACG/MELCOR analytic comparison)	MELCOR Audit Report (passive period)
PCC pool reflood	(TRACG/MELCOR analytic comparison)	MELCOR Intervention Report
Late Transient (Post 7 days):		
PCC efficiency (high M_a)	SET (PANTHERS) SET (UCB/MIT single tube)	Same as above
WW wall H&M transfer	Uchida/Dehbi	CVTR Report (SAND2008-1224)
WW pool H&M transfer	---	---
DW/WW reverse bypass flow	Same as above	Same as above

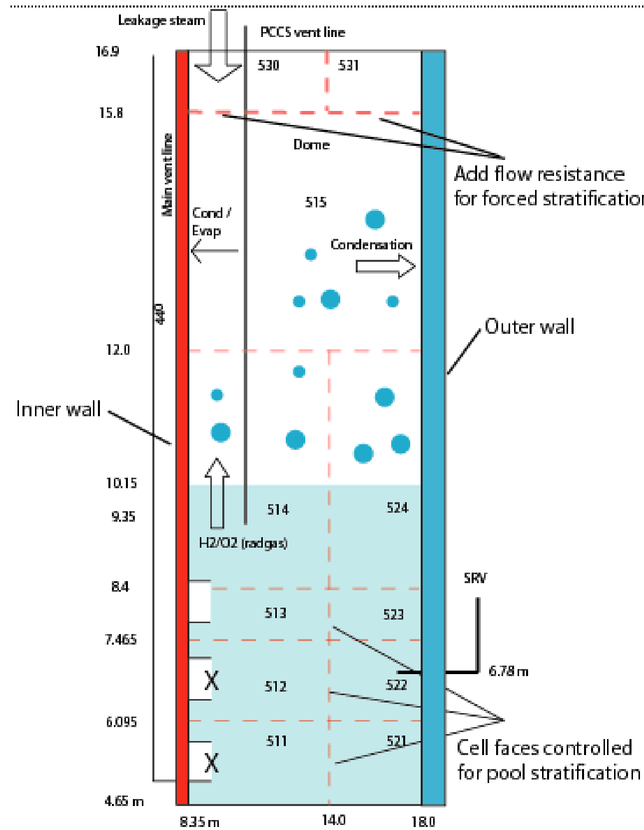
MELCOR ESBWR Plant Model



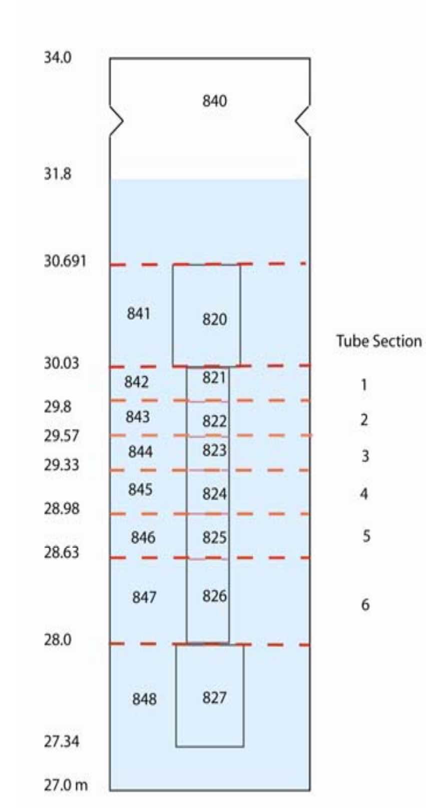
MELCOR ESBWR Plant Model (cont.)

RPV





PCCS (1 of 2)



2/4 Units

TRACG Plant Model

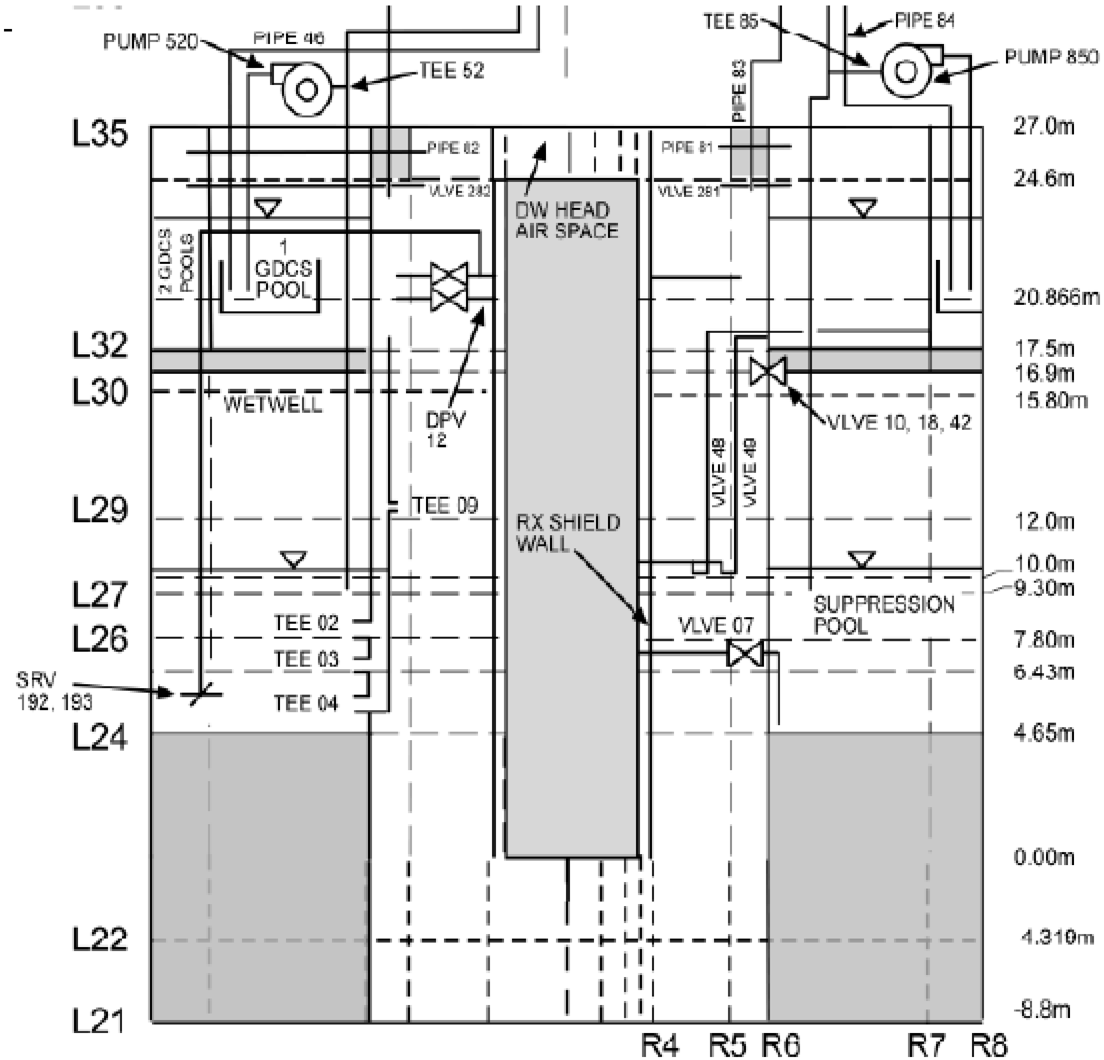


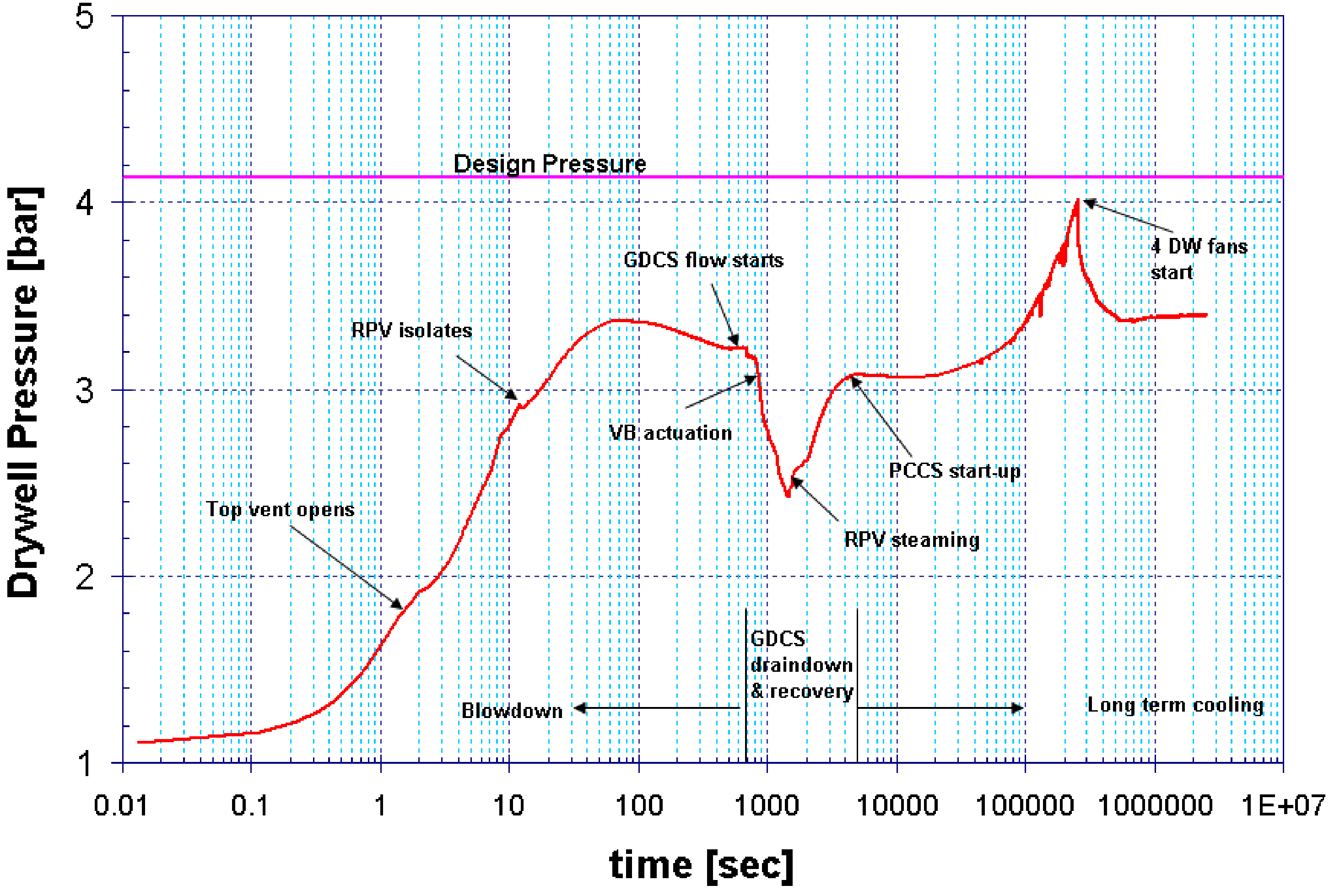
Figure 2. TRACG Nodalization of ESBWR Containment

Audit Modeling Specifications (Passive Period)

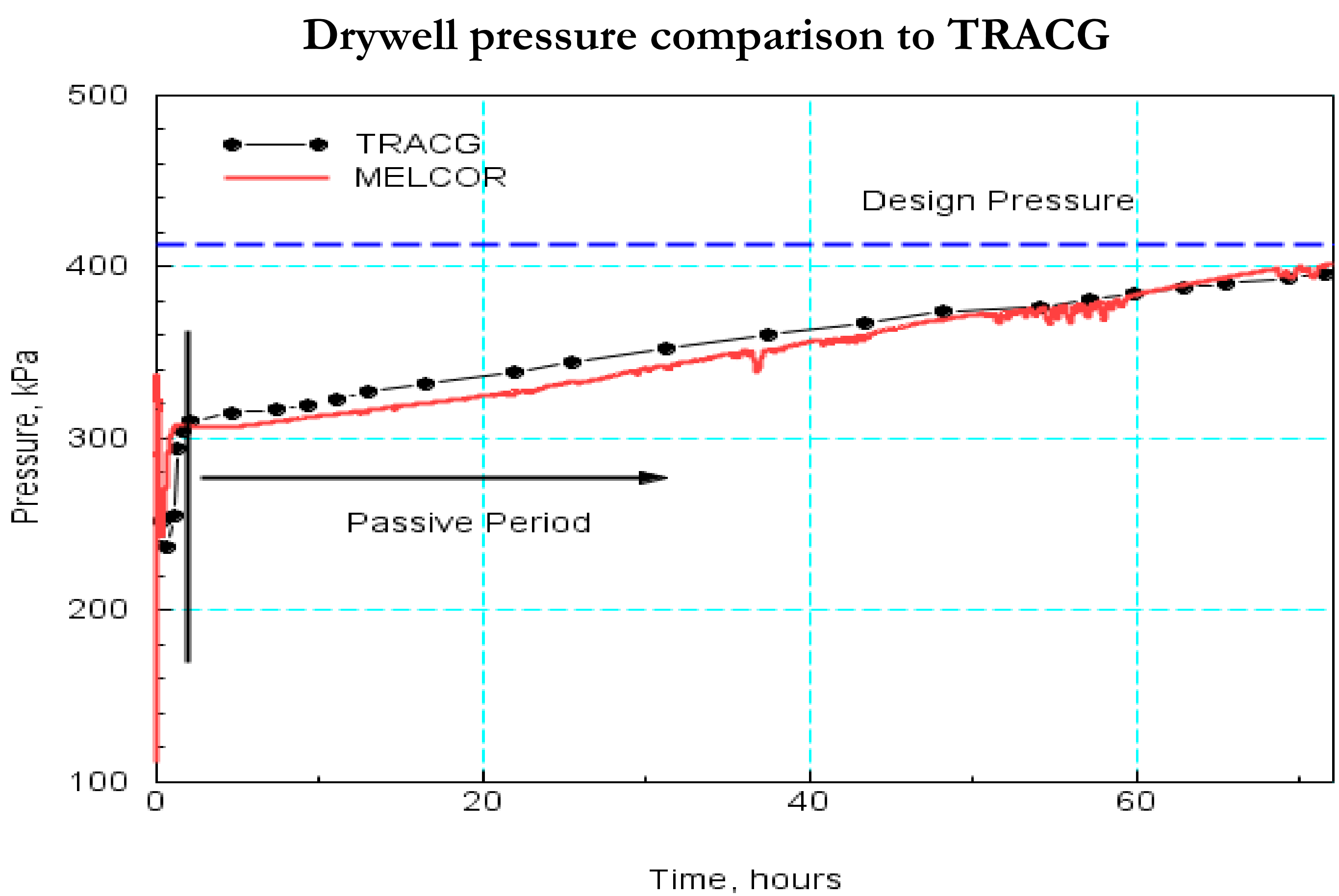
- Wetwell pressurization controls containment pressure
- Need to maximize gas transfer to Wetwell for max short and long-term pressure
- Need to account for DW-WW leakage (2 cm2)

Model Biases [ESBWR NEDC-33083P-A & DCD Rev 4, Table 6A-1]	
Process	**Bounding methodology**
Suppression pool stratification	Horizontal pool pathways below main top vent artificially closed after main vents close following blowdown
Wetwell gas space stratification	High resistance added to top level vertical pathways to restriction vertical circulation of bypass steam entering at the top of the wetwell gas space
Reduced heat sinks	All equipment/piping and drywell structures not connected to wetwell neglected; only wetwell concrete modeled
Circulation of GDCS/drywell gases	Dual pathway connection between GDCS/upper drywell
No PARs modeled	Include continuous radiolytic gas generation
Model Biases [MELCOR additions]	
No drywell trapping of gas	Single volume drywell
Main vent clearing	Conservative pathway inertia lengths*

MELCOR Audit Calculation (MSLB)



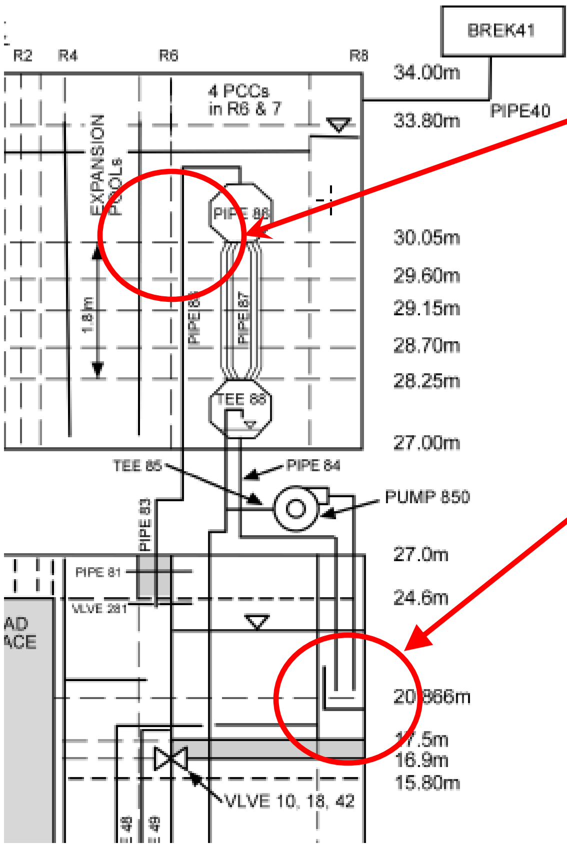
MELCOR Audit Calculation (MSLB)



MELCOR Audit Calculation (MSLB)

- Passive Period
  - Dominant phenomena – Core radiolysis causing PCCS NC gas bounding and bypass leakage of steam from DW to WW
- Intervention Period
  - PARs credited (shutting off radiolysis)
  - DW recirculation fans (4 of 6 functioning)
  - Upper pool refill (constant 200 gpm)

Intervention Period Audit Analysis



DCD Rev6 TRACG Plant Model

- **IC/PCC/Expansion pool refill**

  refill at fixed rate = 200 gpm

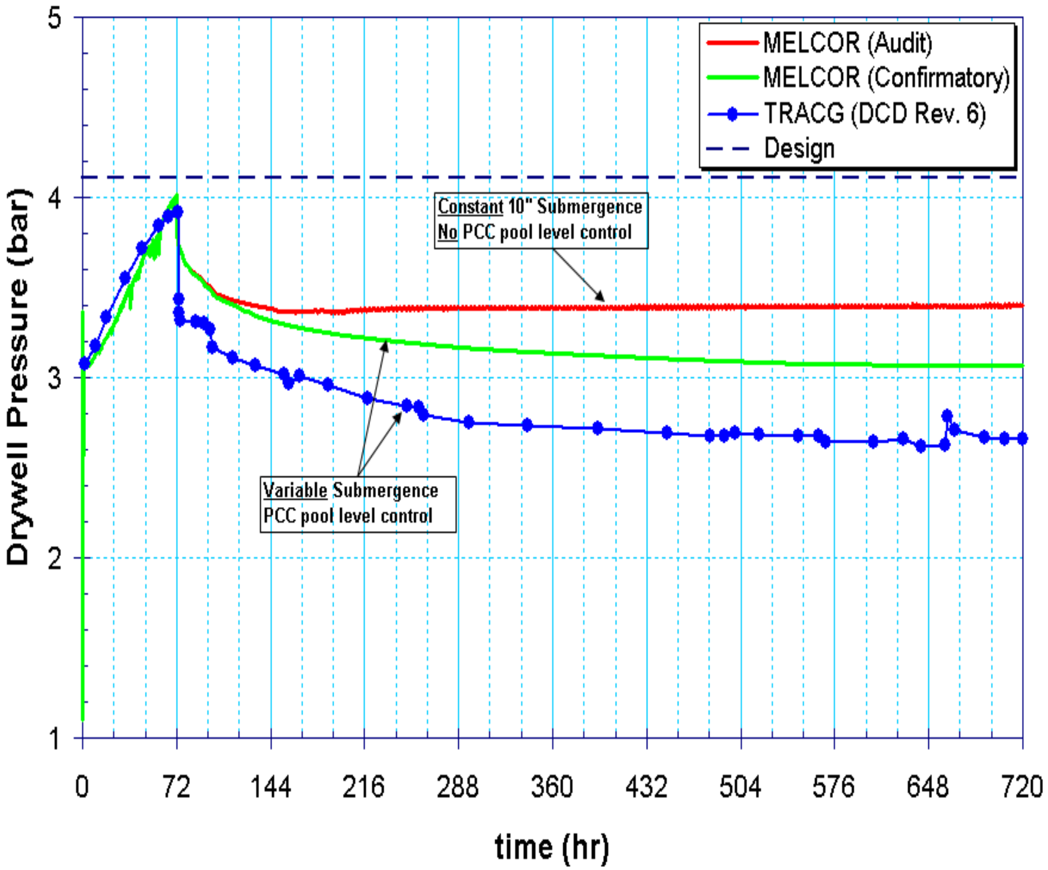
  (with no level control anticipated, except for over-flow situation)

- **Tray in GDCS**

  maintain vent submergence of 10 inches @ start of intervention period and throughout

	Level Control	Constant 10" submergence	Codes
Confirmatory (DCD rev. 6)	Yes	No	TRACG & MELCOR
Audit	No	Yes	MELCOR

Intervention Period Calculation



DCD Rev 6 (TRACG)

- pool level control (variant procedure)
- fan vent with varying submergence (variant design)

Confirmatory Calculation

MELCOR ESBWR plant with level control without GDCS pool tray

ESBWR Containment Audit Summary

- Maximum MELCOR containment pressure at end of passive period compares well with TRACG
- MELCOR predicted audit pressure, based on ESBWR design/operation, during the late intervention period (with GDCS pool tray function and without PCC/IC/Expansion pool refill management) is flat with ~ 24% margin at 30 days (720 hours)
- MELCOR and TRACG intervention period pressure trends are similar when design/operation parameters are similarly modeled

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Revision of RG 1.151
"Instrument Sensing Lines"

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Background

- Current regulatory guide (Revision 0) – has not been updated since July 1983
- Current standard reference – ANSI/ISA-S67.02-1980
- A number of reactor events occurring between 1973 and 1983 led to supplementary guidance in Revision 0 of RG 1.151 for concerns not addressed in ANSI/ISA S67.02-1980
- In the updated ANSI/ISA-67.02.01-1999, ISA combines ANSI/ISA S67.02-1980 with ANSI/ISA-67.10 (ISA standard for sample-line piping and tubing) and incorporates NRC guidance from RG 1.151 Rev. 0
- Public comment period for Draft Regulatory Guide DG-1178 ended on February 06, 2009

Summary of Changes

- Updates the endorsement to ANSI/ISA-67.02.01-1999 excluding the portions associated with sample lines.
- Updates reference to IEEE Std 603-1991.
- Endorses IEEE Std 622-1987 which contains requirements for the proper design of heat tracing systems used for freeze protection and to prevent crystallization of concentrated chemical solutions (such as boric acid).
- Removes supplemental guidance now covered by ANSI/ISA-67.02.01-1999 and IEEE Std 622-1987.

Changes to Regulatory Positions

- Position 1:
  - Removes the supplemental guidance (now covered by ANSI/ISA-67.02.01-1999_Clause 5.4).
  - Excludes the sample line portions of ANSI/ISA-67.02.01-1999 from the endorsement.
- Position 2:
  - Removes the supplemental guidance (now covered by ANSI/ISA-67.02.01-1999_Table 1 & Figure 1a).
  - Clarifies the isolation requirement (excluded from ANSI/ISA-67.02.01-1999) as it applies to sensing lines penetrating containment boundary.

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Changes to Regulatory Positions (Cont.)

Position 3:

- Removes the supplemental guidance (now covered by ANSI/ISA-67.02.01-1999_Table 1 & Figure 2a).
- endorses IEEE Std 622-1987 as an acceptable method for design of heat tracing systems used for freeze protection and to prevent crystallization of concentrated chemical solutions

Position 4:

- Removes the supplemental guidance (now covered by ANSI/ISA-67.02.01-1999_Clause 5.2.1 and IEEE Std 622-1987_Clause 4.1.3)
- Provides guidance not covered in ANSI/ISA-67.02.01-1999 for sensing lines taking into account lessons learned from measurement errors due to the evolution of dissolved non-condensable gases.

Changes to Regulatory Positions (Cont.)

- Position 5: deleted to remove the supplemental guidance (now covered by IEEE Std 622-1987_Clause 5.2.2.4)

- Position 6: deleted to remove the disclaimer associated with ANSI/ISA-S67.02-1980

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BENEFITS OF THE RG UPDATE

- Enhances reactor safety by
  - addressing the most current ANSI/ISA and IEEE standards on safety systems endorsed by the NRC and
  - addressing operational events in which evolved gases in sensing lines have affected measured water levels and provide guidance to prevent such events.

BACKUP

Indication inaccuracies covered by ANSI/ISA-S67.02.01-1999

- *ANSI/ISA-S67.02.01-1999* Section 5.2.1n states:

  "Potential inaccuracies in water level indication during and after rapid depressurization events have been identified as industry concerns and shall be considered. Inaccuracies result from noncondensable gases collecting in the condensate pot (chamber) of instrument reference legs and migrating down the reference leg."

- ANSI/ISA-S67.02.01-1999 recognizes the potential indication inaccuracies during and after rapid depressurization events but provides no specific guidance.

BACKUP (Cont.)

Proposed Changes to Position 4 Based on ACRS Subcommittee Comment

- <u>Current Regulatory Position 4:</u>

  Provisions should be made to mitigate the potential effects of trapped, evolved gases in sensing lines during or following depressurization events as long as the associated measurements are required for monitoring the plant or for operating the safety system. This position is based on GDC 13, GDC 21, GDC 22, and 10 CFR 50.55a(h).

- <u>Proposed Regulatory Position 4:</u>

  In addition to the design guidance provided by ANSI/ISA–67.02.01–1999 for instrument sensing lines, provisions should be made to (a) determine the potential impacts of trapped, evolved gases in instrument sensing lines during or following depressurization events and (b) to mitigate such impacts, as long as the associated measurements are required for monitoring the plant or for operating the safety system. This position is based on GDC 13, GDC 21, GDC 22, and 10 CFR 50.55a(h).

BACKUP (Cont.)
Highlights of Public Comments and Resolutions

- *Comment:* In the discussion section, Draft guide DG-1178 describes the potential for dissolved gas in water filled instrument sensing lines to come out of solution under certain circumstances, adversely affecting the accuracy and reliability of level measurements. It further notes that some actions taken to prevent the condition have been deficient. Regulatory position 4 directs that the provision shall be made to mitigate this problem, but DG-1178 does not include description of a method acceptable to the

  NRC to implement the directive.

  Resolution: A specific mitigation method depends on the sensing line design. For the group of BWR plants that have previously experienced this problem, reference to a particular resolution that was accepted by the staff is included in the discussion section. Other designs of sensing lines may require other approaches. As regulatory guides do not specify the design, the regulatory guidance should not dictate one approach over another.

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BACKUP (Cont.)
Highlights of Public Comments and Resolutions

- *Comment*: a separate Regulatory Guide is needed for dealing with the non-condensable gasses issue. The Regulatory Guide should incorporate the results of the analyses conducted by the BWROG as well as 15 years of BWR plants operating experience with the backfill modification in service. Combining guidance for two issues (design and non-condensable gas) into one Regulatory Guide will not serve as the best guidance.

  Resolution: The inclusion of design provisions for mitigating trapped gas in sensing lines is consistent with the objective of this regulatory guide to provide regulatory guidance on design and installation of safety-related instrument sensing lines. A separate regulatory guide is not required.

BACKUP (Cont.)
RWL Reference Leg Backfill